| | |
|---|---|
| Exhibit No.: | |
| Issues: | Hedging Prudence |
| Witness: | Dana E. Eaves |
| Sponsoring Party: | MoPSC Staff |
| Type of Exhibit: | Direct/Rebuttal Testimony |
| Case No. | EO-2011-0390 |
| Date Testimony Prepared: | March 21, 2012 |



## MISSOURI PUBLIC SERVICE COMMISSION

## REGULATORY REVIEW DIVISION

# DIRECT/REBUTTAL TESTIMONY

# OF

# DANA E. EAVES

# KCP&L GREATER MISSOURI OPERATIONS COMPANY

## CASE NO. EO-2011-0390

**Jefferson City, Missouri**
**February 2011**

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

Staff Ex 1



**NP**

## BEFORE THE PUBLIC SERVICE COMMISSION

## OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of the Third Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of KCP&L Greater Missouri Operations Company | ) ) ) ) ) | Case No. EO-2011-0390 |

### AFFIDAVIT OF DANA E. EAVES

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

Dana E. Eaves, of lawful age, on his oath states: that he has participated in the preparation of the following Direct/Rebuttal Testimony in question and answer form, consisting of 12 pages of Direct/Rebuttal Testimony to be presented in the above case, that the answers in the following Direct/Rebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Dana E. Eaves
Dana E. Eaves

Subscribed and sworn to before me this 21st day of March, 2012.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L Sundermeyer
Notary Public

**TABLE OF CONTENTS**

**DIRECT/REBUTTAL TESTIMONY**

**DANA E. EAVES**

**KCP&L GREATER MISSOURI OPERATIONS COMPANY**

**CASE NO. EO-2011-0390**

**STAFF'S PROPOSED DISSALLOWANCE ........................................................................ 3**

**NATURAL GAS HEDGING GAINS AND LOSSES FOR ON-PEAK SPOT MARKET POWER WERE NOT INCLUDED IN GMO'S FAC .................................................... 5**

**HEDGING ACTIVITIES BASED ON A FLAWED PREMISE ....................................... 11**

**TABLE OF CONTENTS**

**DIRECT/REBUTTAL TESTIMONY**

**DANA E. EAVES**

**KCP&L GREATER MISSOURI OPERATIONS COMPANY**

**CASE NO. EO-2011-0390**

Q. Please state your name and business address.

A. Dana E. Eaves, P.O. Box 360, Jefferson City, MO 65102.

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

A. I am a Utility Regulatory Auditor for the Missouri Public Service Commission ("Commission" or "PSC") in the Resource Analysis Section of the Energy Unit.

Q. Are you the same Dana E. Eaves who participated in the prudency review and preparation of the Public Service Commission Staff's ("Staff's") *Prudence Review of Costs Related to the Fuel Adjustment Clause for the Electric Operation of KCP&L, Greater Missouri Operations Company* ("Staff Report" or "Report") and the proposed recommendation in this case?

A. Yes, I am. On November 29, 2011, the Staff filed its Report, which is attached to this testimony as Schedule DEE-1 (NP) and DEE-2 (HC).

Q. What has been the nature of your duties while in the employment of this Commission?

A. I have conducted and assisted with cost of service reviews, FAC prudency reviews and other compliancy reviews of regulated investor owned utilities operating within the state of Missouri.

Q. Have you previously filed testimony before the Commission?

A. Yes. Please see Schedule DEE-3 and Schedule DEE-4, attached to this testimony, for the list of cases in which I have previously filed testimony or reports.

Q. What is the purpose of your direct/rebuttal testimony?

A. I present Staff's response to portions of the direct testimony of KCP&L Greater Missouri Operations Company's ("GMO" or "Company") witnesses WM. Edward Blunk, Scott H. Heidtbrink and Dr. C.K. Woo, and I present support for the following points:

- Staff's proposed disallowance of ** __________ ** related to losses associated with NYMEX natural gas futures GMO acquired to off-set, hedge, price volatility of electricity in the spot market (an hourly energy market) during peak demand periods;
- Staff's position that because GMO's fuel adjustment clause ("FAC") specifically included hedging costs in the FERC Account 547 fuel costs as recoverable through its FAC, but did not include hedging costs in the FERC Account 555 purchased power costs during the prudence review period then GMO's hedging gains and losses associated with on-peak spot market purchases of electricity[1] being related to purchased power were not a component of GMO's FAC during the prudence review period; and
- Staff's position that the average monthly prices of natural gas, upon which NYMEX natural gas futures contracts are settled, during the prudence review period are not sufficiently correlated with the spot market prices of electricity during the on-peak periods in that same review period for it to have been prudent for GMO to use

[1]On-peak spot market purchases are the energy utilities purchases from the market for the 16 peak hours of usage for weekdays.



NP

NYMEX natural gas futures contracts to hedge its on-peak spot market purchases of electricity. Since the spot market is hourly and the cost of gas in NYMEX natural gas futures contracts is an average monthly price it is difficult to see how there could be a strong correlation between the two sufficient enough to hedge the more time granular spot market prices with the less time granular gas cost of the NYMEX futures.

## STAFF'S PROPOSED DISSALLOWANCE

Q. Does GMO only use NYMEX natural gas futures contracts to hedge its spot market purchases of electricity?

A. No. GMO also uses NYMEX natural gas futures contracts to hedge against price volatility for the gas it uses to burn in its generating plants that produce electricity.

Q. Is Staff proposing a prudence adjustment related to that hedging?

A. No, Staff's adjustment is only related to GMO's use of NYMEX Natural Gas Futures Contracts to hedge its on-peak energy spot market purchases.

Q. Has GMO recovered through its FAC charges losses it incurred from cross hedging on-peak spot market purchases of electricity with NYMEX Natural Gas Futures Contracts?

A. Yes. However, it is Staff's position that it was imprudent for GMO to use natural gas futures contracts as a cross hedge in an effort to mitigate its exposure to price volatility in the spot market for electricity during periods of peak demand for electricity. GMO included these transactions in its Cost Adjustment Factor (CAF) calculations for accumulation periods five (5) (June 1, 2009 to November 30, 2009), six (6) (December 1, 2009 to May 31, 2010), and seven (7) (June 1, 2010 to November 30, 2010). The sum of these accumulation periods is the prudence review period—June 1, 2009 through November 30, 2010.

Q. If the Commission agrees with Staff that GMO's hedging was imprudent, what prudence disallowance is Staff recommending the Commission find in this case?

A. As presented in Schedule DEE-2, Staff is proposing a prudence disallowance of ** __________ **. Staff derived this amount from information GMO provided in response to Staff Data Request No. 0056.

Q. If the Commission agrees, what amount would it order be refunded to GMO's customers?

A. The full ** __________ **, plus interest at the Company's short-term borrowing rate through the time when the refund is made.

Q. When should the refund be made?

A. In GMO's next Cost Adjustment Factor ("CAF") filing after the Commission's decision in this case becomes effective.[2]

Q. Has GMO challenged how Staff calculated the amount of the disallowance it proposes?

A. Yes. In his direct testimony, page 33, lines 8-14, GMO witness Mr. Blunk states:

> Staff determined that number from values I provided in response Staff Data Request No. 56. Staff failed to adjust its claim to conform with the provisions of the Stipulation and Agreement as to Certain Issues in Case No. ER-2007-0004 and the 95 percent Customer's Responsibility adjustment in GMO's FAC tariff. Had Staff made those adjustments, the alleged over collection would have been ** __________ **. Schedule WEB-5 illustrates how I determined the properly adjusted number.

[2] When it filed its Report, the next CAF filing was due January 1, 2012. The Commission did not issue such an order



NP

Q. Did Staff intend to disallow hedging expenses associated with the previous Stipulation and Agreement to which Mr. Blunk refers?

A. No, it was not and is not Staff's intention to include the values associated with the prior stipulation and agreement in Staff's proposed adjustment.

Q. Does Staff agree with Mr. Blunk's revised number for Staff's disallowance that appears in his direct testimony you just quoted?

A. No. On March 7, 2012, Mr. Blunk filed with the Commission a corrected worksheet WEB-5 for his calculation of the prudence disallowance if the Commission agrees GMO's hedging was imprudent as Staff alleges. There Mr. Blunk asserts the correct amount is ** ________ **.

Q. Does Staff agree with his new number?

A. No, at least not yet. At this time Staff does not have sufficient information that it can rely upon to revise the value of its proposed prudency adjustment. Staff has submitted additional data requests to GMO and expects the responses it receives will provide the information it needs to make that determination.

**NATURAL GAS HEDGING GAINS AND LOSSES FOR ON-PEAK SPOT MARKET POWER WERE NOT INCLUDED IN GMO'S FAC**

Q. Would you explain why Staff is asserting GMO's Fuel Adjustment Clause did not include flow through of GMO's gains and losses on the NYMEX natural gas futures GMO acquired to hedge price volatility of on-peak spot market electricity for the prudence review period?

A. During the prudence review period GMO's FAC had the following formulas for FPA and TEC, the factors of which are defined in the FAC tariff sheets attached as Schedule DEE-5:

> FPA = 95% * ((TEC-B) * J) + C+I)
>
> Where FPA = Fuel and Purchased Power Adjustment
> 95% = Customer responsibility for fuel variance from base level.
> TEC = Total Energy Cost = (FC + EC + PP – OSSR)
> FC = Fuel Costs Incurred to Support Sales
> EC = Net Emission Costs
> PP = Purchased Power
> OSSR = Revenues from Off-System Sales
> B = Base energy costs
> J = Energy retail ratio
> C = Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications due to prudence reviews
> I = Interest on deferred electric energy costs calculated at a rate equal to the weighted average interest paid on short-term debt applied to the month-end balance of deferred electric energy costs

Q. What does these FPA and TEC formulas have to do with Staff's proposed prudency adjustment?

A. During the prudency review period GMO's FAC also provided:

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

GMO included the gains and losses from its NYMEX Natural Gas Futures Contracts hedges for its on-peak energy spot market purchases as purchased power "PP" which is used to calculate "TEC" which in turn is used to calculate "FPA." Therefore, Staff's prudency disallowance affects the "PP" (actual cost of purchased energy in FERC Account 555) component which in turn reduces TEC (total energy costs) and the FPA used in setting the CAF.

Q. You earlier stated GMO's FAC was modified during the prudence review period. Were the FAC tariff sheets changed during the prudence review period too?

A. Yes. The FAC tariff sheets that were in effect over the time period of the prudence review period are attached to this testimony in Schedules DEE-5 and DEE-6. The tariff sheets that were in effect from July 5, 2007 to August 31, 2009 are in Schedule DEE-5 and the tariff sheets that were in effect from September 1, 2009 to June 30, 2011 are in Schedule DEE-6.

Q. Do GMO's FAC tariff sheets in Schedule DEE-5 and DEE-6 define in detail what should or should not be included in the PP component of TEC?

A. Yes, on Original and Sheet No. 127.3 FAC tariff (DEE-6), PP is defined as follows:

> PP = Purchased Power Costs:
>
> Purchased power costs reflected in FERC Account Numbers 555, 565, and 575: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expense in Account 555, excluding SPP and MISO administration fees and excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

Q. Are hedging gains and losses associated with on-peak spot market purchases of electricity included in this definition?

A. No, they are not.

Q. Why not?

A. Hedging costs are not specifically listed in the definition of PP, but hedging costs associated with fuel burned for generation of power are specifically listed in the definition of "FC"—fuel costs incurred to support sales found in GMO's FAC in effect for the prudence audit period.

Q How was FC defined in GMO's FAC for the prudence audit period?

A. As follows:

> FC = Fuel Costs Incurred to Support Sales:
>
> - ☐ The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 502: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuel (i.e. tires and bio- fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost (hedging is defined as realized losses and cost minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, fuel used for fuel handling, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.
> - ☐ The following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, hedging costs, fuel additives, fuel used for fuel handling, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees in Account 547.

Q. Where did GMO record its natural gas hedging gains and/or losses, associated with on-peak spot market purchases of electricity?

A. In FERC account 547.

Q. Did it then include its natural gas hedging gains and/or losses, associated with on-peak spot market purchases of electricity in "FC" in its FAC?

A. Yes.

Q. But is not "FC" for fuel costs incurred to support sales, not for costs incurred for purchased power which is what "PP" is for?

A. Yes.

Q. In which FERC Account should GMO have recorded fuel costs?

A. FERC Account 547.

Q. Does it matter whether hedging costs are included in FERC Account 555 or Account 547?

A. For purposes of GMO's FAC it did during the audit review period.

Q. Why?

A. Because GMO recorded these transactions to account "547105 Hedging Settlements" Staff did not realize they were not hedges placed for natural gas used to generate electricity until this prudency review.

Q. How did Staff discover GMO had included in FERC Account 547 its natural gas hedging gains and/or losses, associated with on-peak spot market purchases of electricity?

A. During its prudence review Staff issued a data request to GMO, Staff Data Request No. 0056, in which it requested that GMO provide a detailed breakdown of its hedging costs for the period June 1, 2009 through November 31, 2010. In response the Company provided a worksheet which revealed it had included natural gas hedging gains and/or losses, associated with on-peak spot market purchases of electricity in FERC Account 547.

Q. Is this the same worksheet you referenced earlier in your testimony as Schedule WEB-5 that Mr. Blunk has revised?

A. Yes, it is.

Q. Is GMO's booking its hedging costs for spot market electricity a violation of a Commission Rule?

A. Yes, in Staff's opinion. Missouri regulated utility companies are required by Commission Rule 4 CSR 240-20.030 (Uniform System of Accounts—Electrical Corporations) to maintain their books and records in accordance with FERC's Uniform System of Accounts ("USOA") in effect as of 1994, with exceptions set out in that rule. The USOA definitions for accounts 547 and 555 the Commission adopted by Rule 4 CSR 240-20.030 follow:

> 547 Fuel:
>
> This account shall include the cost delivered at the station (see account 151, Fuel Stock, for Major utilities, and account 154, Plant Materials and Operating Supplies, for Nonmajor utilities) of all fuel, such as gas, oil, kerosene, and gasoline used in other power generation.
>
> 555 Purchased power:
>
> A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc. District purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.
>
> B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

Q. Are you claiming then that GMO did not account for the hedging gains and losses associated with on-peak purchased power properly?

A. Yes. For the review period GMO claims that ** __________ ** of losses associated with its hedging activities are related to on-peak purchased power. However, GMO is recording all natural gas hedging activities to FERC Account 547.

Q. GMO witness Tim M. Rush states in his direct testimony on page 9, lines 20-21, "The Staff of the Commission has reviewed four prior adjustment periods in two prudence audits and found no imprudence." Is that relevant in this case?

A. No, it is not. As I testified earlier, this issue was buried in FERC Account 547. It appears Mr. Rush would have Staff barred from proposing prudency disallowances simply because the Staff did not propose an adjustment or prudency disallowance in a prior case.

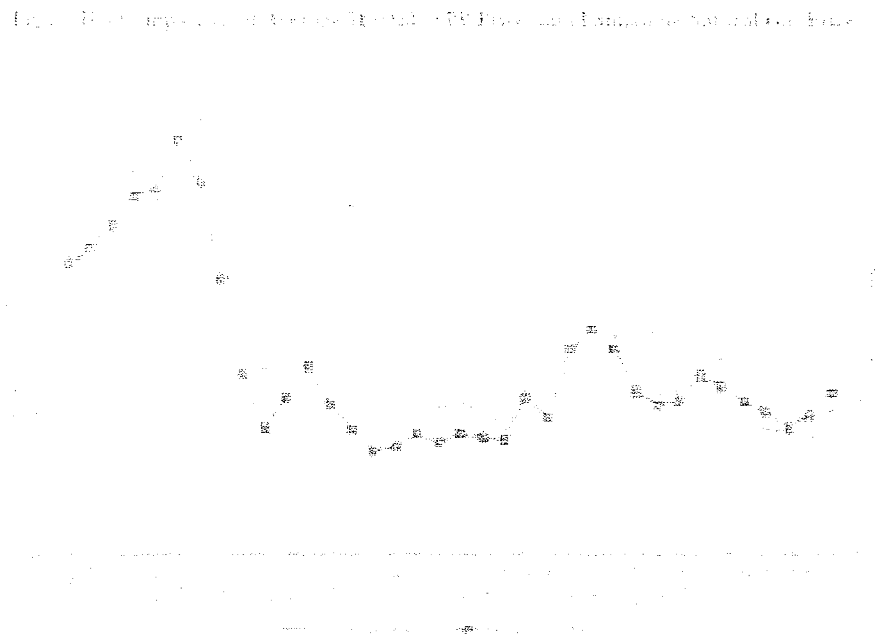
**HEDGING ACTIVITIES BASED ON A FLAWED PREMISE**

Q. Why is Staff asserting GMO's NYMEX natural gas futures GMO hedges against price volatility in the spot market for electricity is based on a flawed premise?

A. Staff's analysis shows there is not a sufficient correlation between the natural gas prices of NYMEX natural gas futures contracts and on-peak spot market prices for electricity to justify GMO's hedging program.

Q. Does GMO's witness Dr. C.K. Woo claim there is a high level of correlation between natural gas prices and on-peak spot market prices for electricity?

A. Yes. And in an effort to support that claim Dr. Woo presents at length in section IV, of his direct testimony, correlations of various regional energy markets to gas prices at various natural gas hubs. Dr. Woo illustrates the relationship of monthly average Panhandle hub gas prices and the Southwest Power Pool ("SPP") monthly average spot market energy prices for 2008-2010 and provides Figure II.6, in his direct testimony, which graphically represents this relationship.



Q. Does Dr. Woo give an opinion, in his direct testimony, that GMO's actual on-peak purchased power hedging activities are prudent?

A. Not that Staff could find. After reviewing Dr. Woo's testimony Staff found this statement on page 19, lines 20-22 and ending on page 20, line 2, that may support GMO's hedging activates:

> Q. When is cross hedging likely effective in this case?
>
> A. When E=1, cross hedging is perfectly effective. This occurs when Var(u)=0 and the electricity spot price and the Henry Hub natural gas spot price are perfectly correlated. Hence, cross hedging is likely to be highly effective when the two spot prices are highly correlated.

Q. Does Dr. Woo provide any analysis based on GMO's specific hedging activities which show they are prudent?

A. No, he does not.

Q. Does Dr. Woo provide a real world example of the correlation between the price of gas in NYMEX natural gas futures contracts and on-peak spot prices for electricity?

A. Yes. On page 26, lines 3-6, of his direct testimony, he states:

> ...the monthly correlation between the Mid-C[3] on-peak electricity spot price and Henry Hub natural gas spot price is about 0.8 for August-April. It is much lower for May-July due to the spring runoff when the marginal generation is primarily hydro power.

Q. What point do you think Dr. Woo is trying to make with this real world example?

A. That cross hedging on-peak spot prices for electricity with natural gas spot prices can be effective in the right circumstances.

Q. Does Dr. Woo explain what a utility's hedging policy should be during periods when the correlation between spot electricity prices and spot natural gas prices is low?

A. No, he does not.

Q. Does GMO operate in the MID-C region to which Dr. Woo refers?

A. No, it does not. In Dr. Woo's direct testimony he provides the following description of the Mid-C region, "The Mid-C hub is a major wholesale spot electricity market in the Pacific Northwest."

Q. Are the Pacific Northwest electric markets comparable with the Midwest electric markets?

A. I have no reason to think they are. Dr. Woo explains the Mid-C region is heavily reliant on hydro facilities while the Midwest region relies heavily on coal and nuclear generation.

---

[3] In Dr. Woo's direct testimony on page 25, line 10, he provides the following description of the Mid-C, "The Mid-C hub is a major wholesale spot electricity market in the Pacific Northwest."

Q. What do you understand correlation to be?

A. Correlation is a predictable and dependable association between two sets of events or sets of data. The most common measure of correlation is the Pearson Product Moment Correlation – called Pearson's correlation for short.

Pearson's Correlation is defined as:

> $r$, can take a range of values from +1 to -1. A value of 0 indicates that there is no association between the two variables. A value greater than 0 indicates a positive association, that is, as the value of one variable increases so does the value of the other variable. A value less than 0 indicates a negative association, that is, as the value of one variable increases the value of the other variable decreases.[4]

Q. Has Staff conducted any analyses regarding the correlation between natural gas prices and spot market electricity prices in the markets where GMO hedged and operated?

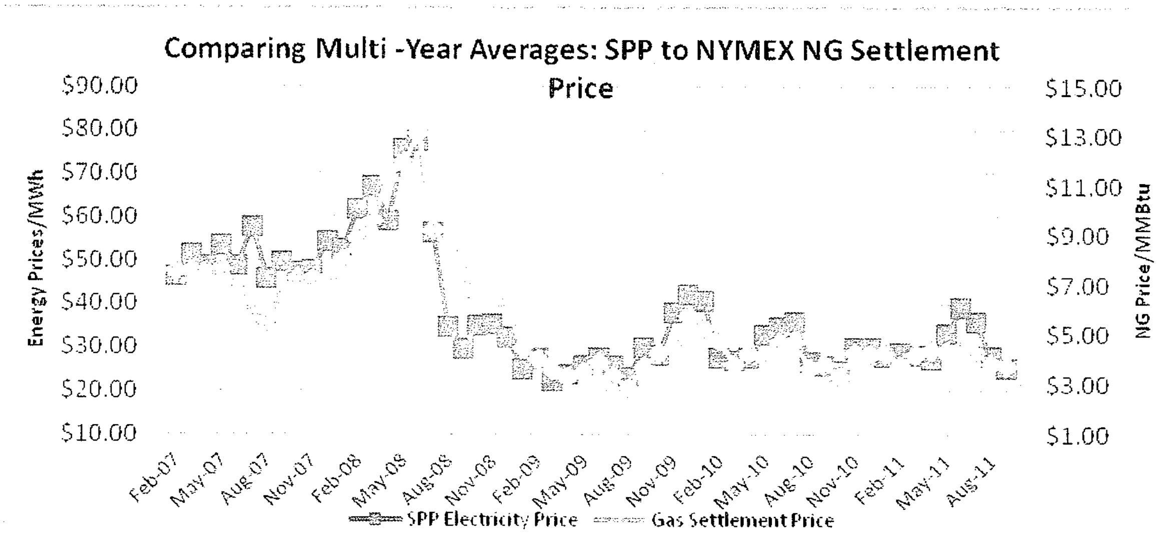
A. Yes. Staff thought it of great importance to provide the Commission with analyses it believes bear on GMO's use of NYMEX natural gas futures contracts to hedge its on-peak spot market purchases of electricity.

Q. What analyses has Staff prepared?

A. Staff prepared an analysis showing monthly NYMEX natural gas settlement prices at the Henry Hub[5] compared to monthly Southwest Power Pool (SPP)[6] spot market electricity prices over a multi-year period. The chart below shows graphically this relationship monthly for the period February 2007 thru December 2011.

[4] https://statistics.laerd.com/statistical-guides/pearson-correlation-coefficient-statistical-guide.php
[5] Staff chose to base its analysis on Henry Hub because NYMEX natural gas futures contracts are priced at this location and SPP and GMO is a member of SPP with would reflect GMO's spot electric prices more accurately.
[6] GMO is a member of the regional transmission organization Southwest Power Pool.

Figure 1




Q. Did Staff determine the correlation co-efficient for the data it used to create the preceding figure?

A. Yes. For the period February 2007 thru October 2011 the data has a correlation co-efficient of 0.8941.

Q. Then are NYMEX natural gas settlement prices and SPP energy prices highly correlated?

A. No. Staff would call this relationship as having a strong positive association for the data set in the analysis period.

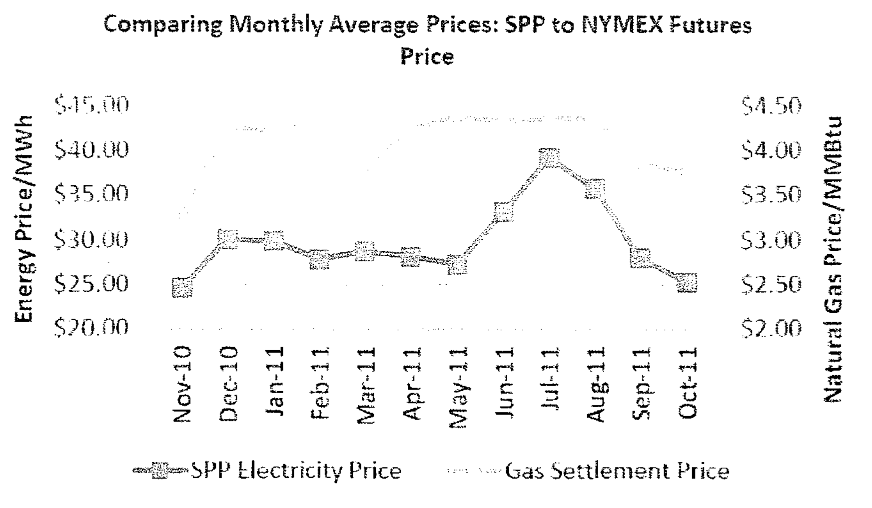
Q. Are there periods within this data set that are less correlated?

A. Yes there are. Just as there is in Dr. Woo's analyses of the Mid-C region, there are periods that are of weaker correlation between Henry Hub natural gas prices and SPP market prices as Figure 2 demonstrates.

Q. Did Staff prepare any other analysis?

A. Yes. Staff chose to use the 12 months ending October 2011 to compare average monthly NYMEX natural gas settlement prices at the Henry Hub with average monthly Southwest Power Pool (SPP) prices for a shorter period. That analysis is presented in the following figure.

Figure 2




Q. Did Staff determine the correlation co-efficient for the data it used to create the preceding figure?

A. Yes. For the period November 2010 thru October 2011 the data has a correlation co-efficient of 0.61755.

Q. Based upon the result of this analysis do you consider NYMEX natural gas settlement price to be highly correlated with SPP energy prices?

A. The strength of the correlation seems to decrease the shorter the increment of time over which the correlation is measured, i.e., the multi-year averages have a much stronger correlation than the monthly averages.

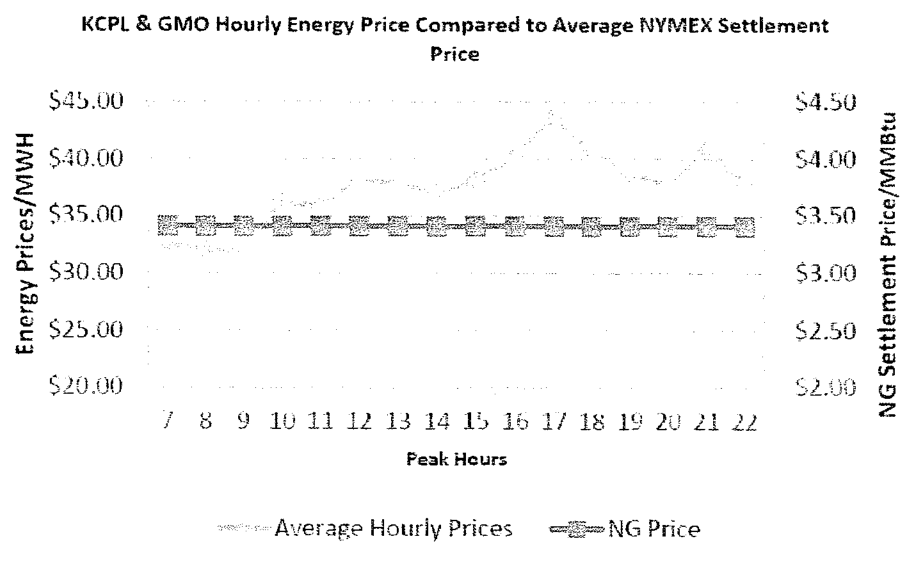
Q. Does that mean that over the long run it would be prudent to hedge NYMEX natural gas prices to offset the volatility of SPP energy prices?

A. Not necessarily. There are other factors to consider besides just a good correlation between data points. In addition, the SPP market is evolving and as a result the correlation observed in the past may not continue in the future.

Q. Did Staff prepare any other analysis?

A. Yes. Staff randomly chose August 3, 2009, and compared what GMO actually paid for peak spot market electricity to GMO's actual NYMEX monthly natural gas settlement price. The result is presented graphically in the following chart labeled Figure 3.

Figure 3




Q. What is the correlation co-efficient of the data set used in creating Figure 3?

A. It is almost 0 (-1E-15).

Q. Based upon that result, is it Staff's opinion monthly NYMEX natural gas settlement prices and the spot market prices GMO actually paid for electricity in August 2009 are highly correlated?

A. No. The analysis results show that the two data sets are not correlated.

Q. Would you explain Figure 3?

A. In this figure "NG Price" is the actual monthly NYMEX futures settled price GMO provided to Staff in response to Staff Data Request No. 0056.2. "MMBTU PP" is an average hourly price GMO and KCPL supplied to Staff in their monthly 3.190 data filings.

Q. Would the results change if Staff had chosen a different period for its analysis?

A. No.

Q. Why not?

A. The correlation of a flat set of data points (monthly gas price) against a set of data points that fluctuate (hourly on-peak prices) will show little or no correlation. If both sets of data points are flat (monthly gas price and monthly average hourly purchased power price) the correlation will be perfect for that month.

Q. How would you explain this data in context of Mr. Woo's statement, "Hence, cross hedging is likely to be highly effective when the two spot prices are highly correlated."?

A. After analyzing the data specifically related to GMO's hedging practice, Staff's opinion is that the data shows little or no correlation when placed in context of GMO's actual practices, which involve buying power at hourly market prices cross hedged with NYMEX futures. Staff points out that when actual daily on-peak energy prices are compared to the Last Day Settlement Price ("LDSP"), the method used in valuing the monthly NYMEX natural gas futures settlement price, it reveals this relationship is not correlated. Staff's analysis shown in Figure 3 dramatically demonstrates this lack of correlation when analyzing GMO's actual data and practices.

Q. Has GMO provided any studies to Staff performed before GMO implemented its cross hedging program that show its hedging policies were prudent?

A. GMO's response to Staff's Data Request No. 0085 provided an Excel spread sheet that purports to show a high level of correlation between NYMEX Henry Hub natural gas monthly settlement values and the monthly average day-ahead on-peak for SPP pricing points and the average of those SPP pricing points.

Q. Is this information similar to what Staff has provided in this testimony?

A. Yes, the results are similar.

Q. Is this the only analysis GMO provided Staff to show the prudency of it utilizing this hedging strategy?

A. Yes. Staff is not aware of any detailed studies or analysis performed prior to GMO implementing its cross hedging activities.

Q. In your opinion should GMO have performed comprehensive studies relating to its current cross hedging activities prior to implementing them?

A. Yes. Staff believes it would be imprudent for GMO to place so much of rate payer monies at risk without fully analyzing its cross hedging policies.

Q. Is the extent of GMO's reliance on spot market purchases to meet peak demands for electricity typical of regulated Missouri utilities?

A. No, as supported by GMO's response to Staff's Data Request No. 0058, where GMO stated the following:

> With over 40 percent of GMO's energy requirements being supplied through purchased power, GMO has a significant exposure to the volatility of the power market. . . . .
>
> * * **
>
> GMO is heavily reliant on purchased power to serve its load. In 2010 GMO purchased more power than KCP&L and Union Electric combined. With fewer "non-requirements sales for resale" GMO

> purchased about twice as many MWhs as Empire District Electric.....

Q. What are some of the factors, other than natural gas, which influence the price of on-peak spot market electricity?

A. Weather, system congestion, and unplanned outages are three major influences.

Q. In the past, has GMO ever provided testimony as to whether natural gas price is the only price driver for electric energy prices?

A. I am aware that in Case No. ER-2007-0004 Mr. Davis Rooney, a witness for Aquila, provided the following question and answer on page 22, lines 8-10, of his Direct Testimony in that case:

> Q. Is natural gas the only driver of spot purchased power prices?
> A. No. However, it certainly is one of the most volatile. As noted above, purchased power prices are impacted by more than just natural gas prices.

Q. Can Staff provide any quantification of the impact of natural gas prices on on-peak spot market electricity prices?

A. Yes. In Project No. 21409, Rulemaking Relating to Price to Beat, before The Public Utility Commission of Texas, on page 25, as attached as DEE-7, the Texas Commission reported:

> Reliant and other commenters[sic] asserted that natural gas prices have not historically been perfectly correlated with power prices. In fact, Reliant asserted that since power began trading in ERCOT gas price movements explain only 17% of the variance in electric price movements.

Q. Do GMO's hedging practices mitigate any risk associated with these other price drivers?

A. They do not. Since GMO has chosen not to closely match physical power quantities using negotiated heat rates and prices of power purchased from a third party, instead of purchasing from the spot market, GMO is susceptible to these same price risk drivers without hedging natural gas futures. In fact, the way GMO has structured its hedging plan appears to increase the risk it incurs when the market price for natural gas is trending lower and GMO continues to hedge. In that circumstance GMO is almost assured to only realize losses in its hedging activities and the risk GMO is exposed to for on-peak electricity spot market prices remains the same. That is clearly demonstrated by GMO's actual results.

Q. Mr. Blunk refers to training provided by PGS Energy Training in his direct testimony, does he not?

A. Yes, he does, on page 16, lines 6-12. There he refers to a webinar provided by PGS Energy Training titled; "How to Financially Hedge Natural Gas & Electricity Price Risk" and provides a copy of the webinar description as Schedule WEB-1.

Q. Has Staff attended this webinar?

A. Yes, in response to Company's Data Request No. 0083 the Staff provided a listing for all Staff that has attended this PGS training.

Q. Did you attend this webinar?

A. Yes, I attended this webinar Mr. Blunk refers to on January 18, 2008.

Q. Does the training in this webinar validate GMO's hedging practices?

A. No, it does not. On slide 16 of Mr. Adamiak's presentation for this webinar, attached as DEE-8, he makes the following statement:

**Hedging with Energy Futures Contracts**

- Remember, it's just a way to fix a forward price.
- Inappropriate hedging can actually increase a firm's risk.

Q. Does Mr. Heidtbrink on pages 9-10 in his direct testimony make characterizations about statements made by Chairman Jeff Davis in his Concurring Opinion in Case No. ER-2007-0004?

A. Yes. As I interpret Mr. Heidtbrink questions and answers he would have the reader believe Chairman Davis approved of GMO's hedging activities?

Q. Do you agree with that characterization of Chairman Jeff Davis' statements?

A. No, if Chairman Jeff Davis' Concurring Opinion, attached as DEE-9, is reviewed in its entirety, I find a different conclusion should be drawn. In my opinion, Chairman Jeff Davis is putting "Aquila" on notice regarding its prudency of its hedging practice and he provided the following statement:

> Aquila should be very mindful that the majority of this commission took a bold step in awarding Aquila a fuel adjustment mechanism. This commission and the General Assembly will be watching. If Aquila fails to adopt a proper hedging strategy, fails to follow its hedging strategy or abuses the discretion given to it by this commission in any other way, this commissioner will not hesitate to modify or reject Aquila's FAC application in a future proceeding.

Q. In your opinion, should the hedging gains and losses GMO incurred for the prudence review period that are related to it cross hedging on-peak spot market purchases of electricity with NYMEX Natural Gas Futures Contracts be recovered through GMO's FAC

A. No, they should not.

Q. Why not.

A. GMO's hedging activities that generated them were imprudent.

Q. Does this conclude your testimony?

A. Yes it does.

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

**June 1, 2009 through November 30, 2010**

**MISSOURI PUBLIC SERVICE COMMISSION**
**STAFF REPORT**

**FILE NO. EO-2011-0390**

*Jefferson City, Missouri*
*November 28, 2011*

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

**NP**

# Table of Contents

I. EXECUTIVE SUMMARY ..... 1

II. INTRODUCTION ..... 2

A. GENERAL DESCRIPTION OF GMO'S FAC ..... 2

B. PRUDENCE STANDARD ..... 5

III. FUEL AND PURCHASED POWER ..... 6

A. UTILIZATION OF GENERATION CAPACITY ..... 6

B. UTILIZATION OF PURCHASED POWER AGREEMENTS ..... 7

C. PURCHASED POWER COSTS ..... 8

D. PLANT OUTAGES ..... 11

E. HEDGING ACTIVITIES ..... 11

F. NATURAL GAS COSTS ..... 14

G. COAL COSTS ..... 14

H. FUEL OIL COSTS ..... 15

I. ALTERNATIVE FUELS ..... 16

J. $SO_2$ ALLOWANCES ..... 17

K. ENVIRONMENTAL WORK AT SIBLEY AND JEFFREY ..... 19

L. IATAN 2 FUEL AND PURCHASED POWER COSTS ..... 20

M. OFF-SYSTEM SALES REVENUE ..... 22

N. MPOWER RIDER/DEMAND RESPONSE PROGRAM ..... 23

O. C. W. MINING COST ..... 24

P. INTEREST COST ..... 25

# Prudence Review of Costs Report

## I. Executive Summary

The Missouri Public Service Commission ("Commission") first authorized a Fuel Adjustment Clause ("FAC") for Aquila, Inc. ("Aquila") in Case No. ER-2007-0004. The Commission approved the acquisition of Aquila, by Great Plains Energy, Inc. and subsequently Aquila was renamed KCP&L Greater Missouri Operations Company ("GMO" or "Company")[1]. This acquisition became effective July 14, 2007. Since then, the Commission has approved continuation of GMO's FAC with modifications in its orders in the Company's general rate cases, Case No. ER-2009-0090 and File No. ER-2010-0356.

Missouri statute and Commission rule, Section 386.266.4(4) RSMo (Supp. 2010), and 4 CSR 240-20.090(7), respectively, require prudence reviews of an electric utility's FAC no less frequently than at 18-month intervals. In this prudence review Staff analyzed items affecting GMO's cost of fuel, purchased power, net emissions allowances, and revenues from off-system sales for the fifth, sixth and seventh six-month accumulation periods of GMO's FAC ("prudence review period"). The fifth accumulation period started June 1, 2009 and ended November 30, 2009, the sixth accumulation period started December 1, 2009 and ended May 31, 2010, and the seventh accumulation period started June 1, 2010 and ended November 30, 2010. Thus, the 18-month prudence review period that is documented in this Prudence Review Report is from June 1, 2009 through November 30, 2010. This is Staff's third Prudence Review Report for GMO's FAC.

Staff filed its first Prudence Review Report in File No. EO-2009-0115. That report covered the first two six-month accumulation periods of GMO's FAC—the period June 1, 2007 through May 31, 2008. Staff filed its second Prudence Review Report in File No. EO-2010-0167. That report covered the third and fourth six-month accumulation periods of GMO'S FAC—the period June 1, 2008 through May 31, 2009.

[1] In Case No. EN-2009-0164 the Commission recognized, by order dated November 20, 2008 and made effective December 3, 2008, the name change of Aquila, Inc. d/b/a KCP&L Greater Missouri Operations Company to KCP&L Greater Missouri Operations Company. At different points in time the company now named KCP&L Greater Missouri Operation Company was known as, or did business in Missouri as, Aquila, Inc., Aquila Networks-MPS, Aquila Networks-L&P and KCP&L Greater Missouri Operations Company. For ease, in this report the Company will be uniformly referred to as "GMO" or "Company."

In evaluating prudence, Staff reviews whether a reasonable person making the same decision would find both the information the decision-maker relied on and the process the decision-maker employed was reasonable based on the circumstances at the time the decision was made, *i.e.*, without the benefit of hindsight. The decision actually made is disregarded and the review is an evaluation, instead, of the reasonableness of the information the decision-maker relied on and the decision-making process the decision-maker employed. If either the information relied upon or the decision-making process employed was imprudent, then Staff examines whether the imprudent decision caused any harm to ratepayers. Only if an imprudent decision resulted in harm to ratepayers, will Staff recommend a refund.

Staff analyzed a variety of items in examining whether GMO was prudent when making decisions related to costs and revenues associated with its FAC for the period June 1, 2009 to November 30, 2010.

Staff has found GMO was imprudent in its use of natural gas hedges to mitigate risk associated with its future purchases in the spot power market. Staff recommends the Commission order GMO to refund the amount of ** _______ **, plus interest at the Company's short-term borrowing rate through the time the refund is made, in the context of Cost Adjustment Factor ("CAF") filing number eight. CAF filing number eight is scheduled to be made January 1, 2012. It has an associated recovery period of March 1, 2012 to February 28, 2013.

## II. Introduction

### A. General Description of GMO's FAC

For each accumulation period, GMO's Commission-approved FAC allows GMO to recover (if the net costs exceed) or refund (if the net costs are less than) to its ratepayers ninety-five percent (95%) of the "net fuel cost" defined as the difference between its prudently incurred variable fuel, purchased power and net emissions costs plus off-system sales revenue, and the base energy cost amount. GMO accumulates variable fuel, purchased power and net emissions costs plus off-system sales revenue during six-month accumulation periods. Each six-month accumulation period is followed by a twelve-month recovery period where the over- or under-recovery during the previous six-month accumulation period relative to the base energy cost amount is flowed through to ratepayers by an increase or decrease in the

FAC CAF. An adjustment to the CAF is designed to offset that over- or under-recovery for a given accumulation period ("AP") by the end of the twelve-month recovery period ("RP"). Because the CAF rarely, if ever, will exactly match the required offset, GMO's FAC is designed to true-up the difference between the revenues billed and the revenues authorized for collection during recovery periods. Any disallowance the Commission orders as a result of a prudence review shall include interest at the Company's short-term interest rate[2] and will be accounted for as a true-up item.

The following three tables summarize the net fuel cost, true-up amounts and interest amounts for AP 5, AP 6 and AP 7 respectively. In general, revenues authorized for collection, but not billed, during a previous recovery period (true-up) are added to the net fuel costs of a future accumulation period. Interest is applied to net fuel costs, beginning with the month after the fuel costs occurred, and to the true-up for a recovery period, beginning with the month after the recovery period ends.

| Table 1 | | |
|---|---|---|
| Fuel Adjustment: AP5 File No. EO-2010-0191 | | |
| True-Up: RP2 Case No. EO-2008-0415 | | |
| Rate Cases: Case Nos. ER-2007-0004 and ER-2009-0090 | | |
| Calendar Period: June 1, 2009 - November 30, 2009 | | |
| | | |
| | Rate District | |
| Cost Component | MPS | L&P |
| 95% Net Fuel Cost | $8,448,250 | $177,607 |
| True-Up | $804,362 | $125,393 |
| Interest | $216,064 | $14,822 |
| Total | $9,468,676 | $317,822 |
| | | |

[2] Rule 4 CSR 240-20.090(7)(A).

| Table 2 | | |
|---|---|---|
| Fuel Adjustment: AP6 File No. ER-2010-0385 | | |
| True-Up: RP3 File No. ER-2010-0254 | | |
| Rate Case: Case No. ER-2009-0090 | | |
| Calendar Period: December 1, 2009 - May 31, 2010 | | |
| | | |
| | Rate District | |
| Cost Component | MPS | L&P |
| 95%Net Fuel Cost | $15,094,285 | $2,554,639 |
| True-Up | $768,873 | $377,151 |
| Interest | $421,355 | $41,847 |
| Total | $16,284,513 | $2,973,637 |
| | | |

| Table 3 | | |
|---|---|---|
| Fuel Adjustment: AP7 File No. ER-2011-0179 | | |
| True-Up: RP4 File No. ER-2011-0180 | | |
| Rate Case: Case No. ER-2009-0090 | | |
| Calendar Period: June 1, 2010 - November 30, 2010 | | |
| | | |
| | Rate District | |
| Cost Component | MPS | L&P |
| 95% Net Fuel Cost | $16,189,677 | $1,710,512 |
| True-Up | -$185,256 | $35,349 |
| Interest | $559,589 | $66,475 |
| Total | $16,564,010 | $1,812,336 |
| | | |

Each total is the fuel and purchased power adjustment ("FPA") amount for the accumulation period which is used to determine the current period CAF for each subsequent recovery period. A period CAF rate is calculated for each recovery period by dividing the FPA amount by forecasted retail net system input (kWh) during the recovery period, rounded to the nearest $0.0001. The annual CAF rate is the sum of the applicable current and previous period CAF rates. A separate line item appears on each retail customer's bill with the label "FAC." That line item represents the charge to that customer to recover from that customer, that customer's share of the FPA for the applicable periods plus interest. Tables 4 and 5 show

GMO's CAF rates per kWh for AP 5, AP 6 and AP 7 for the MPS and L&P customers, respectively.

| Table 4 : MPS | | | |
|---|---|---|---|
| Accumulation Period | AP 5 | AP 6 | AP 7 |
| CAF Primary and above | $0.0070 | $0.0065 | $0.0054 |
| CAF Secondary | $0.0071 | $0.0065 | $0.0055 |

| Table 5 : L&P | | | |
|---|---|---|---|
| Accumulation Period | AP 5 | AP 6 | AP 7 |
| CAF Primary and above | $0.0012 | $0.0022 | $0.0022 |
| CAF Secondary | $0.0012 | $0.0022 | $0.0023 |

**B. Prudence Standard**

In *State ex rel. Associated Natural Gas Co. v. Public Service Com'n of State of Mo.*, 954 S.W.2d 520, 528-29 (Mo. App. W.D., 1997) the Western District Court of Appeals stated the Commission's prudence standard as follows:

> The PSC has defined its prudence standard as follows:
>
> [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 an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent. (Citations omitted).
>
> *Union Electric*, 27 Mo. PSC (N.S.) 183, 193 (1985) (quoting ***529** *Anaheim, Riverside, Etc. v. Fed. Energy Reg. Com'n*, 669 F.2d 799, 809 (D.C.Cir.1981). 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.
>
> *Union* Electric, 27 Mo. P.S.C. at 194 (quoting *Consolidated Edison Company of New York, Inc.* 45 P.U.R. 4th 331 (1982)).

In reversing the Commission in that case, the Court did not criticize the Commission's definition of prudence, but held, in part, that to disallow a utility's recovery of costs from its ratepayers based on imprudence, the Commission must determine the detrimental impact of that imprudence on the utility's ratepayers. *Id.* at 529-30

This is the prudence standard Staff has followed in this review.

## III. Fuel and Purchased Power

The cost of fuel and purchased power for the purpose of GMO's FAC is comprised of four major components: Fuel Costs, Purchased Power Costs, Off-System Sales Revenue and Net Emission Allowances Costs.

### A. Utilization of Generation Capacity

#### 1. Description

GMO generates much of its own power. The following generating station units provided base load energy during the Prudence Review Period: Sibley 1, 2, and 3; Lake Road 4/6; Jeffrey Energy Center[3] 1, 2, and 3; and Iatan 1.[4] GMO's remaining units provided intermediate and peak energy. Those units are Greenwood 1, 2, 3 and 4; South Harper 1, 2, and 3; Ralph Green 3; Lake Road 1, 2, 3, 5 and 7; Nevada; and KCI 1 and 2. During 2010, Kansas City Power & Light Company was completing construction and startup of Iatan 2[5]. Iatan 2 began commercial operations in December 2010, which is one month beyond the period of this prudence review. A capacity balance sheet is included as Attachment 1.

#### 2. Summary of Cost Implications

Staff reviewed the generation assets of GMO, and how GMO met its required load and reserve margin during the audit period. If GMO had been imprudently managing its generation capacity, *e.g.*, using its peaking units to serve base load demand, ratepayers could be harmed by increased fuel costs recovered through GMO's FAC.

#### 3. Conclusion

Staff found no indication GMO imprudently dispatched its units during the Prudence Review Period.

#### 4. Documents Reviewed

a. Commission Report and Order in File No. ER-2010-0356;

---

[3] GMO is joint owner (8%) of the Jeffery Energy Center units.
[4] GMO is joint owner (18%) of Iatan 1.
[5] GMO is joint owner (18%) of Iatan 2.

b. GMO responses to Staff Data Request Nos. 0011, 0014, 0015, 0016, 0017, 0018, 0019, 0020, 0023, 0024, 0036, 0049 issued in this case; and
c. Monthly generation data GMO submitted in compliance with 4 CSR 240-3.190.

*Staff Expert: Leon C. Bender*

**B. Utilization of Purchased Power Agreements**

**1. Description**

In addition to obtaining power from the generating units it owns during the prudence review period, GMO received energy and capacity through three long-term purchased power agreements ("PPA"). GMO had two baseload PPAs with the Nebraska Public Power District and a wind energy PPA with Gray County Wind Farm. GMO also had a tolling agreement with Crossroads Energy Center ("Crossroads"). Crossroads is a four-unit generating station consisting of four combustion turbines ("CT") with a total capacity of approximately 300 MWs that is located in Clarksdale, Mississippi. It was originally built by Aquila Merchant Services Inc. as a merchant plant. GMO's tolling agreement entitled it to the capacity and the energy output of Crossroads in exchange for payments sufficient to cover the fixed and variable costs, "the toll", incurred to produce the energy output and maintain and operate Crossroads. In GMO's most recent general electric rate case, File No. ER-2010-0356, the Commission ordered the Crossroads station to be added to GMO's rate base in May 2011, well after the end of this prudence review period.

In addition to the three long-term PPAs, GMO had three short-term PPAs during the prudence review period for energy and capacity. These agreements were with Westar Energy for energy and capacity from the Dogwood combined cycle unit; Associated Electric Cooperative, Inc.; and Public Service Company of Colorado d/b/a Xcel Energy (both of which are system agreements).

**2. Summary of Cost Implications**

If GMO imprudently entered into one or more PPAs for additional energy to meet its demand, evidence of imprudence regarding the resulting purchased energy would only be found if the cost of the energy obtained through the PPA(s) exceeded the cost of generating the energy by GMO generating capacity or the cost of purchasing the energy on the spot market. If GMO imprudently entered into PPAs, ratepayer harm could result from an increase in costs to be collected through the FAC.

### 3. Conclusion

Staff found GMO's long-term, base-load agreements to be reasonable as they are below both the cost of generating power with its own peaking units and the cost of purchased power. Staff found GMO's short-term contracts to be reasonable as they were used to meet GMO's short-term peaking capacity requirements at a cost below the cost of generating power of GMO's highest cost peaking generating units. Staff found no indication of imprudence by GMO for entering into long-term and short-term purchased power contracts.

### 4. Documents Reviewed

a. GMO Responses to Staff Data Requests Nos., 0011, 0014, 0015, 0016, 0017, 0018, 0019, 0020, 0023, 0024 and 0049 in this case; and
b. Monthly purchases and sales data GMO submitted in compliance with 4 CSR 240-3.190.

*Staff Expert: Leon Bender*

## C. Purchased Power Costs

### 1. Description

Staff reviewed spot market purchases and the results of GMO's natural gas hedging activities linked to spot market purchases.

In addition to the PPAs discussed above, GMO also purchases hourly energy in the market from other electric suppliers to help meet GMO's load during times of forced or planned plant outages and during times when the market price is below both the marginal cost of providing that energy from GMO's generating units and purchased power contracts.

GMO's FAC tariff defines the Purchase Power Costs ("PP") components as:

PP = Purchased Power Costs:

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

In its review of GMO's spot market costs for the review period, Staff found that GMO included in its spot market costs, along with the spot market energy costs, hedging losses associated with natural gas future contracts that it incurred in an effort to mitigate risk associated with purchasing spot market power. In a response to Staff's Data Request No. 56

directed to GMO, Mr. Ed Blunk of GMO explains GMO's purpose for linking natural gas future contracts to on-peak purchases of power in the following answer:

** **

2. **Summary of Cost Implication**

Staff alleges GMO imprudently linked natural gas future contracts with spot market purchases for purchased power and sought recovery for the resulting hedging gains and/losses through the FAC. If GMO is allowed to recover these losses through the FAC, ratepayer harm will result from an increase in costs collected through the FAC.

3. **Conclusion**

The Staff does not find GMO's actions related to PPA costs to be imprudent; however, after reviewing the "PP" component of GMO's FAC, Staff does not find that the costs of hedging natural gas costs to mitigate risk associated with purchases of spot market power are recoverable as a component of "PP" in GMO's CAF calculation. As a result of reviewing GMO's FAC tariff sheets for this prudence review period, Staff finds that it was imprudent for GMO to include its hedging costs associated with purchases of natural gas futures contracts to mitigate risk associated with its on-peak spot market purchases in its fifth, sixth and seventh accumulation period CAFs. Staff knows of no formal organized market that allows for spot purchased power to be hedged which would aid GMO in mitigating the risk associated with buying spot market purchased power. It appears in the absence of such a formal market GMO has tried to create its own purchased power hedge market by purchasing NYMEX natural gas futures contracts to offset its risk in the spot market for purchased power. Staff concludes that purchasing natural gas futures contracts to mitigate risk associated with the purchase of spot purchase power is imprudent. The two markets (NYMEX Natural Gas and Purchase Power

Markets) are not directly linked sufficiently that a prudent person would use option purchases in the natural gas futures market to prudently offset the risk of price volatility in the spot purchased power market. Under GMO's concept, GMO's actions are akin to placing a bet in the stock market in hopes of generating enough cash to pay for a future variable expense. GMO's "hedging" practice actually increases GMO's risk exposure, to the detriment of GMO's ratepayers; GMO must guess right when placing the bet, otherwise the initial risk exposure to volatile spot purchase power market remains. GMO's linking of natural gas futures contracts with purchases it makes in the spot market for purchased power is imprudent.

Staff has determined GMO's total purchased power expense, that GMO is seeking to be recovered for the 18-month period reviewed, including hedging losses, is approximately ** ___________ **. In GMO's response to Staff's Data Request No. 0056, it reports the amount of hedging losses related to hedges placed to protect on-peak purchased power to be ** _______ ** for the period June 1, 2009 through November 30, 2010. GMO also reports, for the same period, its cost for purchases to be ** ___________ **.

Staff recommends the Commission find it was imprudent for GMO to link natural gas futures purchase contracts with spot market purchases for purchased power during the audit period of June 1, 2009 through November 30, 2010, and order GMO to refund the amount of ** _______ **, plus interest at the Company's short-term borrowing rate through the time the refund is made, in the context of CAF filing number eight. CAF filing number eight is scheduled to be made January 1, 2012. It has an associated recovery period number eight of March 1, 2012 to February 28, 2013

**4. Documents Reviewed**

a. GMO's responses to Staff Data Request Nos. 1, 2, 20, 55, 56, 58 & 59 in File No. EO-2011-0390 and GMO's responses to Staff Data Request No. 20 in File No. EO-2010-0167; and
b. GMO's filings in this case and FAC tariff sheets.

*Staff Expert: Dana Eaves*

## D. Plant Outages

### 1. Description

Outages occurring at any generating unit can have an impact on how much GMO will pay for fuel and purchased power, and could result in the Company incurring more fuel cost than necessary. Outages can be either planned or unplanned. Staff examined the outages and the timing of the outages to determine if the outages were prudent. An example of an imprudent outage would be planning an outage of a large coal unit during a peak demand period.

### 2. Summary of Cost Implications

An imprudent outage could result in GMO purchasing expensive spot market power or running its more expensive gas units to meet demand thereby causing the Company to incur higher fuel costs than it would otherwise have incurred. If GMO was imprudent in when it incurred its plant outages, ratepayer harm could result from an increase in the fuel costs that are collected through GMO's FAC.

### 3. Conclusion

Staff found no indication GMO's plant outages were imprudent during the time period examined in this prudence review.

### 4. Documents Reviewed

a. GMO responses to Staff Data Requests Nos. 0003, 0004, 0005, 0026, 0037 and 0050; and
b. Monthly Outage data submitted by GMO in compliance with 4 CSR 240-3.190.

*Staff Expert: Leon Bender*

## E. Hedging Activities

### 1. Description

GMO's natural gas hedging activities can be divided into two separate areas. The first can be described as a traditional natural gas price hedge plan. The second is best described as non-traditional hedging activities related to spot market purchased power.

In the first instance, through the use of financial hedges, GMO attempts to reduce the risk of operating natural gas generation plants by hedging against the fluctuations in price of natural gas used to generate electricity.

Hedging is defined as:

> **hedging,** method of reducing the risk of loss caused by price fluctuation. It consists of the purchase or sale of equal quantities of the same or very similar commodities, approximately simultaneously, in two different markets with the expectation that a future change in price in one market will be offset by an opposite change in the other market.[6]

**2. GMO's Natural Gas Hedging Practice**

In response to Staff's data request No. 0055 Ed Blunk describes changes to GMO's hedging practice:

> KCP&L GMO (formerly Aquila) has been employing a natural gas hedging strategy developed by Kase and Company, Inc. since July 2007. In December 2010, [Kansas City Power & Light Company] consolidated its and GMO's natural gas hedge strategies. The consolidated hedge strategy is not significantly different than Aquila's July 2007 strategy.

Kansas City Power & Light Company's (KCPL) and GMO's joint Natural Gas Price Hedge Plan describe how Kase and Company, Inc. (Kase) assists KCPL and GMO with price risk management as follows:

> Kase and Company, Inc. (Kase) assisted KCPL and GMO in establishing natural gas price risk management programs, which employ disciplined, methodical approaches to hedging, This Price Hedge Plan combines both the KCPL and GMO (formerly Aquila) programs into one program. It is to be executed with ongoing consultation from Kase to ensure the models are being correctly applied and actions are filtered by sound business judgment. The program is oriented toward finding a balance between the need to protect against high prices while not unreasonably limiting opportunities to purchase gas at low prices. This balanced approach is sought by apportioning the Hedge Volume between two different methodologies for evaluating current market prices. Those programs are Kase's HedgeModel and ezHedge.
>
> While both of Kase's models are effective there are differences between the two. HedgeModel is used to place hedges on any of the hedge strips using both fixed price instruments and options. HedgeModel also offers exit points that can be used to remove and restructure hedges. It offers the user some discretion in hedge placement and hedge instruments. ezHedge generates buy signals that can be embedded in physical purchases or executed via swaps or futures. It uses only one hedge length rather than the several used by HedgeModel. With ezHedge, positions are held to expiration, unless they are shifted to the HedgeModel positions.

---

[6] http://www.britannica.com/EBchecked/topic/259286/hedging.

**Objective**

The objective of this price risk management program is to reduce the price risk inherent with floating with the market without substantively degrading the Company's overall competitiveness. The program's goals are to 1) protect the Company and its customers from large upward fluctuations in the price of natural gas and 2) assure a reasonable probability that budgets are met in a cost-effective manner.

Staff reviewed GMO's natural gas hedging activities against the stated objectives contained within GMO's natural gas price hedge plan.

**3. Hedging activities for Purchased Power**

GMO utilizes the same price risk management strategies to purchase natural gas future contracts[7] in an effort to mitigate risk associated with purchasing spot power in the market when either GMO is unable to meet its native load with its own generation or when the market price is lower than the cost of GMO's own generation.

**4. Summary of Cost Implications**

As a result of its natural gas hedging activities, GMO had a net loss, *i.e.*, it purchased natural gas future contracts at a price higher than the market price, of approximately ** _______ ** for the June 1, 2009 to November 30, 2010, time period of this review. In response to Staff Data Request No. 58, GMO stated that approximately ** _______ ** of this amount is directly related to its hedging activities for its own generation of electricity. The remaining approximately ** _______ ** is directly related to its natural gas hedging activities associated with spot market purchases. Because the Company's financial hedging program is used to avoid market fluctuations in natural gas prices, there will be times when GMO benefits and times when it does not. If GMO has imprudently made financial hedges to mitigate risk in its spot market natural gas fuel purchases, ratepayer harm could result from an increase in the fuel costs GMO recovers through its FAC.

**5. Conclusion**

Staff found GMO's hedging activities related to natural gas used for electric generation to be in compliance with GMO's natural gas price hedge plan. However, Staff

[7] Natural gas future contracts are marketed thru New York Mercantile Exchange (NYMEX). These can be classified as financial hedges, only a financial transaction occurs and no physical gas commodity will change hands between the parties.

finds GMO's actions imprudent as related to the use of futures contracts to purchase natural gas as a means of mitigating risk associated with spot market purchased power. This issue was discussed previously in the Purchased Power Costs section of this report.

### 6. Documents Reviewed

a. GMO's responses to Staff Data Requests Nos. 1, 2, 55, 58, & 59; and
b. GMO's filings in this case and FAC tariff sheets.

*Staff Expert: Dana Eaves*

## F. Natural Gas Costs

### 1. Description

For the prudency review period approximately 6% of the electricity GMO generated to serve its customers came from natural gas. Staff concluded that approximately ** _______ ** of GMO's fuel cost was associated with the natural gas used in generating electricity. The cost of natural gas includes various miscellaneous charges such as firm transportation service charges and other fuel handling expenses.

### 2. Summary of Cost Implications

If GMO was imprudent in its purchasing decisions relating to natural gas, rate payer harm could result from increased FAC charges.

### 3. Conclusion

Staff found no indication GMO's purchases of natural gas for the fifth, sixth and seventh accumulation periods reviewed in this case were imprudent.

### 4. Documents Reviewed

a. GMO's responses to Staff Data Request Nos. 1, 2, and 31 related to GMO's hedging of natural gas prices from June 1, 2009 to November 30, 2010; and
b. GMO's General Ledger, cost adjustment factor calculation ("CAFC"), and other work papers from this case to determine the amount that GMO paid for natural gas as compared to the total cost of natural gas that GMO incurred during its fifth, sixth and seventh accumulation periods.

*Staff Expert: Dana Eaves*

## G. Coal Costs

### 1. Description

For the prudence review period approximately 90% of the electricity GMO generated to serve its customers came from coal. Staff concluded that approximatelv

** __________ ** of GMO's fuel cost was associated with the coal used in generating electricity. The cost of coal includes various miscellaneous charges such as rail and other ground transportation service charges, and other fuel handling expenses.

**2. Summary of Cost Implications**

If GMO was imprudent in its decisions relating to purchasing coal, rate payer harm could result from an increase in FAC charges.

**3. Conclusion**

Staff found no indication GMO's purchases of coal for the fifth, sixth and seventh accumulation periods of GMO's FAC from June 1, 2009 to November 30, 2010 were imprudent.

**4. Documents Reviewed**

a. GMO's fixed coal contracts in place for the delivery of coal to each of its generating units;
b. GMO's responses to Staff Data Request Nos. 1, 2 and 4; and
c. GMO's General Ledger, CAFC, and other work papers to determine the amount that GMO paid for coal as compared to the total cost of coal that GMO incurred during its fifth, sixth and seventh accumulation periods.

*Staff Expert: Dana Eaves*

**H. Fuel Oil Costs**

**1. Description**

For the prudency review period approximately 0.45% of the electricity GMO generated to serve its customers came from fuel oil. Staff concluded that approximately ** _______ ** of GMO's fuel cost was associated with the fuel oil used in generating electricity. The cost of fuel oil includes various miscellaneous charges, such as rail and/or ground transportation service charges and other miscellaneous fuel handling expenses.

**2. Summary of Cost Implications**

If GMO imprudently purchased fuel oil, rate payer harm could result from increased FAC charges.

### 3. Conclusion

Staff found no indication GMO's costs associated with its fuel oil contracts in place for June 1, 2009 to November 30, 2010, the prudence review period in this case, were imprudent.

### 4. Documents Reviewed

a. GMO's General Ledger;
b. GMO's responses to Staff Data Request Nos.1, 2, 4, and 30; and
c. CAFC and other supporting work papers in this case to determine the amount GMO paid for fuel oil as compared to the total cost of fuel oil GMO incurred during its fifth, sixth and seventh accumulation periods.

*Staff Expert: Dana Eaves*

## I. Alternative Fuels

### 1. Description

At GMO's Sibley Generating Station, which has cyclone-fired boilers, two types of alternative fuel were burned during the prudence review period—tire-derived fuel ("TDF") and biomass. Sibley Unit 3 has been burning TDF since 1997, and TDF is considered part of the normal fuel supply. TDF is a higher energy value fuel than the bituminous coal used at Sibley. TDF increases the overall heat input to the boiler. Cyclone-fired units require a certain amount of ash content in the fuel to maintain a slag layer in the cyclone unit. TDF is low in ash and therefore the amount of TDF that can be blended with coal is limited. Prior to the installation of the Selective Catalytic Reducer (SCR) to Sibley Unit 3 in late 2008, the maximum blend ratio was ** ________________ **. The maximum blend ratio was reduced to less than ** ____ ** after installation of the SCR. The cost of TDF includes material, transportation, labor and equipment for material handling at the plant, including personnel to manage and load TDF during normal weekday hours.

At Unit 4/6 at the Lake Road Generating Station, TDF is the only type of alternative fuel that was burned during the prudence review period. Lake Road Unit 4/6 has been burning TDF since 2004 and is currently using a maximum blend ratio of ** ____ **.

GMO conducted a biomass test burn at Sibley Unit 2 in December 2009. The purpose of the test burn was to determine the maximum amount of biomass that could be combusted without causing operational problems or a decrease in unit performance. Parameters that were evaluated at different amounts of biomass combustion included boiler efficiency, heat rate, boiler cleanliness, emissions, ash resistivity, ammonia in ash, and overall ash characteristics. The biomass used during the test burn was a pelletized fuel consisting of grass, weed seed, and a small amount of storm damaged wood. The test burn met all of the data gathering objectives for operating the unit with a biomass/coal fuel blend.

For the 18-month period ending November 30, 2010, used for the Staff review, GMO's alternate fuel expense used for generation was approximately ** _______ **.

**2. Summary of Cost Implications**

If GMO's use of alternative fuels was imprudent, ratepayer harm could result from an increase in FAC charges.

**3. Conclusion**

Staff found no indication GMO's use of alternate fuels for the time period June 1, 2009 through November 30, 2010, was imprudent.

**4. Documents Reviewed.**

a. Company response to Staff's Data Requests Nos. 0001, 0007 and 00047; and
b. Staff workpapers from Case No. ER-2009-0090.

*Staff Expert: David Roos*

**J. $SO_2$ Allowances**

**1. Description**

The U.S sulfur dioxide ($SO_2$) emission allowance trading program was established by Title IV of the 1990 Clean Air Act Amendments ("CAAA"). The program is intended to reduce environmental and human health impacts associated with the release of sulfur emissions from coal-fired electric power plants. CAAA requires electric utilities to reduce their $SO_2$ emissions by about 50% from 1980 levels, or purchase allowances to meet this standard.

Under CAAA power plants are allocated a 30-year stream of tradable allowances, each worth one ton of $SO_2$. The allocation of allowances is based on an average capacity factor from the period 1985 to 1987. Allowances are awarded by the Environmental Protection Agency ("EPA") every year, and are designated by vintage year. The vintage year denotes the first year the allowances may be used for compliance. Unused allowances can be sold or banked for use in subsequent years.

The US EPA's Clean Air Interstate Rule ("CAIR"), issued in 2005, was developed to address the transport of pollutants from upwind to downwind states. States in the eastern half of the country were required, over a six-year compliance period (2009-2015), to participate in a federal program intended to reduce emissions of $SO_2$ by 57% from 2003 levels and Nitrogen Oxide ($NO_X$) by 61% from 2003 levels.

However, a number of petitions for judicial review of CAIR were filed in the D.C. Circuit Court, and on July 11, 2008, the D.C. Circuit Court of Appeals vacated the CAIR. A December 2008 court decision temporarily kept the requirements of CAIR in place and directed EPA to issue a new rule to implement Clean Air Act requirements concerning the transport of air pollution across state boundaries. On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") that regulates power plant emissions of $SO_2$, $NO_X$, ozone and fine particulates. The requirements of CAIR were in effect during the prudence review period. The requirements of CSAPR were not in effect during the prudence review period; however, CSAPR requirements affect future accumulation periods.

The primary mechanism of CAIR is a cap-and-trade program that allows a major source of $NO_X$ and/or $SO_2$ to trade excess allowances when its emissions of a specific pollutant fall below its cap for that pollutant. EPA issued a model cap-and-trade program for power plants, which could have been used by states as the primary control mechanism under CAIR. Under CAIR, starting in 2010, owners of power plants are required to submit two $SO_2$ allowances for each ton of $SO_2$ emitted. This ratio is further tightened in 2015 to 2.86 allowances for each ton of $SO_2$ emitted.

Since the 1980's, the Sibley and Lake Road plant capacities have more than doubled; Iatan 1 had a slight increase in capacity, while the Jeffrey Energy Center had a slight decrease in capacity. In addition, GMO's purchased power contract with the Nebraska Public Power District's Gerald Gentleman power plant requires GMO to supply $SO_2$ allowances. The net effect is that GMO does not have enough allowances to cover its $SO_2$emissions requirements, and must purchase $SO_2$ allowances.

To comply with CAIR, GMO has established an $SO_2$ inventory. This inventory is tracked in Account 158100 Emissions Allowance Inventory. The cost for $SO_2$ allowances is tracked in FERC account 509. A true-up for account 509 coincides with the EPA yearly award of additional $SO_2$allowances.

For the 18 months of the prudence review period ending November 30, 2010, GMO's $SO_2$ allowance expense was approximately ** ________ **.

**2. Summary of Cost Implications**

If GMO imprudently used, purchased or banked it $SO_2$ allowances, ratepayer harm could result from an increase in GMO's FAC charges.

**3. Conclusion**

Staff found no indication GMO was imprudent in its purchases, banking or usage of $SO_2$ allowances. Based on the documents reviewed, it appears that the variations from the baseline set in the rate case are caused by changes in the price per $SO_2$ allowance and the number of allowances used during the accumulation periods. The number of allowances used is a function of the tons of coal burned during the accumulation periods and the sulfur content of the coal.

**4. Documents Reviewed**

a. Company response to Staff's Data Request Nos. 0001, 0012, 0038, 0040, 0041 and 0043; and
b. GMO monthly reports for the time period June 1, 2009 through November 30, 2010, required by 4 CSR 240-3.161(7).

*Staff Expert: David Roos*

**K. Environmental Work at Sibley and Jeffrey**

**1. Description**

Several regulatory-driven air pollution control projects were in various phases of construction and operation during the 18-month prudence review period ending November 30, 2010. These projects include:

| | |
|---|---|
| Sibley Unit 3: | Selective Catalytic Reducer (SCR) |
| Sibley Units 1 and 2: | Selective Non-Catalytic Reducer (SNCR) |
| Jeffrey Energy Center: | Replacing / rebuilding three scrubbers |

The SCR for Sibley Unit 3 and the SNCR for Sibley Units 1 and 2 became operational in late 2008. The three scrubbers at the Jeffery Energy Center were completed November 24, 2008, January 6, 2009, and July 22, 2010. GMO's FAC does not allow for the recovery of construction or operational costs for these environmental projects and no expenses from these projects have passed through GMO's FAC.

### 2. Summary of Cost Implications

If GMO had included the costs of environmental work at Sibley and Jeffrey in its FAC, ratepayer harm would result from an increase in GMO's FAC charges.

### 3. Conclusion

Staff found no indication GMO included in its FAC charges any costs for the air pollution control projects at Sibley and Jeffrey Energy Center during the three six-month accumulation periods from June 1, 2009 through November 30, 2010.

### 4. Documents Reviewed

a. GMO responses to Staff Data Request Nos. 001, 0012, 0047; and
b. GMO monthly reports for the time period June 1, 2009 through November 30, 2010, required by 4 CSR 240-3.161(7).

*Staff Expert: David Roos*

## L. Iatan 2 Fuel and Purchased Power Costs

### 1. Description

On August 18, 2010, the Commission approved the terms of a *Nonunanimous Stipulation and Agreement/Proposed Procedural Schedules* in File No. ER-2010-0356 in which GMO agreed to request an Accounting Authority Order to use construction accounting for Iatan 2 and Iatan Common Plant. Construction accounting is defined in the agreement as follows:

> The Signatory Parties agree that GMO should be allowed to treat the Iatan 2 project under "Construction Accounting" to the effective date of new rates in the 2010-11 Rate Case. Construction Accounting will be the same treatment for expenditures and credits consistent with the treatment for Iatan 2 prior to Iatan 2's commercial in service operation date. Construction Accounting will

include treatment for test power and its valuation consistent with the treatment of such power prior to Iatan 2's commercial in service operation date with the exception that such power valuation will include off-system sales.

As required by the agreement, GMO requested, in File No. EU-2011-0034, authority to use construction accounting from the in-service date of Iatan 2 until the effective date of the rates in File No. ER-2010-0356, and the Commission issued an Accounting Authority Order granting GMO's request on October 8, 2010.

**2. Summary of Cost Implications**

Iatan 2 was deemed "in-service" August 26, 2010, during Accumulation Period 7 (June 1, 2010 through November 30, 2010). Under "Construction Accounting" the fuel costs for Iatan 2 are deferred to a regulatory asset account until June 25, 2011, the effective date of the rates the Commission approved in File No. ER-2010-0356 by order issued May 4, 2011. For the period of this prudence review, GMO deferred approximately ** _______ ** of test fuel under "Construction Accounting" from July 2010 through November 2010; *i.e.* energy from Iatan 2 was valued at ** _______ ** in the fuel costs for the prudence review period. For the period December 1, 2010 through June 25, 2011, Staff will review the fuel and purchased power costs under "Construction Accounting" for Iatan 2 in its next prudence review. On June 25, 2011, and thereafter, the fuel and purchased power costs related to Iatan 2 will flow through GMO's FAC, and Staff will review those costs for Iatan 2 in its next prudence review.

**3. Conclusion**

Staff found no indication GMO was imprudent with regard to its fuel and purchased power associated with Iatan 2 for the fifth, six, and seventh accumulation periods of GMO's FAC which cover the period June 1, 2009 to November 30, 2010.

**4. Documents Reviewed**

Staff reviewed the following documents and its attachments in data request 0051:

a. Nonunanimous Stipulation and Agreement/Proposed Procedural Schedules in Case No. EO-2005-0329;
b. Report and Order issued July 28, 2005 in Case No. EO-2005-0329;
c. Application of KCP&L Greater Missouri Operations Company for Approval of An *Accounting Authority Order* in File No. EU-2011-0034;

d. Order Granting Accounting Authority Order issued September 28, 2010, in File No. EU-2011-0034;
e. Iatan Fuel Spreadsheet in response to Staff Data Request No. 0051;
f. Iatan 2 Test Energy White Paper authored by Roberta Hunter, with Great Plains Energy written June 15, 2010, in response to Staff Data Request 0051; and
g. Iatan 2 Test Energy White Paper Amendment authored by Roberta Hunter written November 17, 2010, in response to Staff Data Request 0051.

*Staff Expert: Matthew Barnes*

## M. Off-System Sales Revenue

### 1. Description

Off-system sales revenues ("OSSR") are a component in the calculation of GMO's FAC charges to its customers. They are defined in GMO's FAC Tariff Schedule No. 1 Original Sheet No. 127.3 as follows:

OSSR = Revenues from Off-System Sales:

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

For the prudence review period of June 1, 2009 to November 30, 2010, Staff found that GMO's level of off-system sales revenue was approximately ** _______ **.

Staff reviewed the off-system sales quantities and revenues over the prudence review period.

### 2. Summary of Cost Implications

GMO's revenues from off-system sales are offset against total fuel and purchased power costs. This is because GMO's ratepayers pay for the sources used for that energy that GMO sells off of its system.[8] If GMO was imprudent either because it made sales at a price less than the cost to generate the power sold or did not make off-system sales, ratepayers could be harmed by that imprudence by an increase in GMO's FAC charges.

### 3. Conclusion

Staff has not determined GMO acted imprudently in its actions relating to OSSR during the review period.

### 4. Documents Reviewed

a. GMO's responses to Staff Data Request Nos. 1, 2, 6, 21, & 28; and

[8] Serving those ratepayers (native load) is a higher priority than making an off-system sale.

b. GMO's filings in this case and FAC tariff sheets.

*Staff Expert: Dana Eaves*

## N. MPower Rider/Demand Response Program

### 1. Description

GMO offers a demand response program which is defined in GMO's MPower Rider Electric Tariff Schedule No. 1 Original Sheet No. 128 as follows:

> Purpose
> This voluntary rider (MPOWER Rider or Rider) is designed to reduce customer load during peak periods to help defer future generation capacity additions and provide for improvements in energy supply.

### 2. MPower Program

Staff has reviewed GMO's MPower tariff provisions and program details. Staff believes that demand response is a valuable resource and should be considered as such within GMO's portfolio of resources. In GMO's response to Staff's Data Request No. 0052 GMO states:

> The company is maintaining the existing contracts in the MPower program. As a result of market fundamentals in SPP, GMO can acquire capacity in the open market at a lower price than is available through the MPower program. GMO stopped promoting the program in August, 2009. The company established a waiting list for those customers interested in enrolling in the program.

### 3. Summary of Cost Implications

Although Staff understands the current economic conditions have generally depressed capacity prices and demand response may not be the least cost option currently, these conditions will surely change in the future. A robust MPower program would aid GMO in having all least-cost options available to the benefit of its customers.

### 4. Conclusion

Staff encourages GMO to pursue a robust MPower program that would provide adequate demand response resources for times when it would be the least cost resource. If the price that GMO is currently offering is higher than the market price, GMO can market the program to its customers on the waiting list at a lower rate and provide another option to meet demand at a lower cost.

### 5. Documents Reviewed

a. GMO's responses to Staff Data Requests No. 52, 53 & 54; and
b. GMO's filings in this case and FAC tariff sheets.

*Staff Expert: Dana Eaves*

## O. C. W. Mining Cost

### 1. Description

This issue involves any settlement payments for a breached coal contract between GMO and C.W. Mining, and the effect any settlement payments may have on FAC-related costs. A detailed description of this issue is provided in Staff's prudence review report for GMO in Case No. EO-2009-0115. The following is a brief summary of the events related to this issue.

GMO entered into a coal supply contract with C. W. Mining in January 2004 to supply coal for the Sibley and Lake Road generating stations. In the early portion of the contract, C.W. Mining was unable to supply the contracted quantity of coal, ultimately breaching the contract. This resulted in GMO having to burn higher cost coal at these two generating stations. GMO is currently involved in litigation to recover the higher costs that it incurred as a result of the termination of the C. W. Mining coal contract.

The Stipulation and Agreement as to Certain Issues the Commission approved by its *Order Approving Stipulation and Agreement as to Certain Issues* in Case No. ER-2007-0004 effective on April 22, 2007, stated that settlement payments, net of certain GMO costs, were to flow back to customers through GMO's FAC if the Commission granted GMO a FAC. Since the Commission approved GMO's FAC with its *Report and Order* in Case No. ER-2007-0004, customers are to receive 95% of the C. W. Mining litigation proceeds, net of applicable legal and collection fees and costs as agreed to in the Stipulation and Agreement as to Certain Issues.

No garnishments or settlements from C. W. Mining have flowed through GMO's FAC as of November 30, 2010. Once all legal expenses have been recovered, 95% of any future settlements received will be refunded to customers through GMO's FAC.

### 2. Summary of Cost Implications

There are no cost implications to GMO's FAC from the C. W. Mining litigation during the 18-month period ending November 30, 2010. Since the C.W. Mining contract was set up to provide coal to both the Sibley and Lake Road stations, in a previous FAC Prudence Review Report (Case No. EO-2009-0115), Staff recommended, and GMO concurred in its response to Staff Data Request 0055, that any net settlement payments be split: 81% for ratepayers in the MPS rate district and 19% for ratepayers in the L&P rate district. If GMO imprudently flowed the C. W. Mining settlements through its FAC, or did not flow them through it, ratepayer harm could result from the ratepayers not receiving any of the benefit from the net settlement payments.

### 3. Conclusion

Staff found no indication GMO has acted imprudently regarding the C. W. Mining settlements with respect to its FAC. Staff will continue to monitor this issue in future GMO FAC prudence audits. If GMO receives any future settlement proceeds, the appropriate allocation of the settlement amount between MPS and L&P rate districts will be reviewed at the time the settlement proceeds are flowed through GMO's FAC.

### 4. Documents Reviewed

a. Direct Testimony of Staff witness Cary Featherstone in Case No. ER-2007-0004;
b. *Stipulation and Agreement as to Certain Issues* filed April 4, 2007, in Case No. ER-2007-0004;
c. *Order Approving Stipulation and Agreement as to Certain Issues* entered in Case No. ER-2007-0004, effective April 27, 2007;
d. GMO Monthly and Quarterly Reports submitted in compliance to 4 CSR 240-3.161(5) and (6); and
e. GMO responses to Staff Data Request, No. 0046.

*Staff Expert: David Roos*

## P. Interest Cost

### 1. Description

During each accumulation period GMO is required to calculate a monthly interest amount based on GMO's short-term debt borrowing rate that is applied to the under-recovered or over-recovered fuel and purchased power costs. The short-term debt is GMO's $400 million revolving credit facility and the borrowing rate is based on the 1-month London Interbank Offered Rate (LIBOR) plus an investment grade margin. The investment grade margin is determined by the bank issuing the short-term debt and the Company's long-term credit rating. For the period in review, GMO's interest amount applied to the under-recovered or over-recovered fuel and purchased power costs were $1,400,932 and $154,846 for MPS and L&P respectively. The interest amount is component "I" of the CAFC.

2. **Summary of Interest Implications**

If GMO imprudently calculated the monthly interest amounts or used short-term debt borrowing rates that did not fairly represent the actual cost of GMO's short-term debt, ratepayers could be harmed by FAC charges that are too low or too high.

3. **Conclusion**

Staff found no evidence GMO imprudently determined the monthly interest amount that was applied to the under-recovered or over-recovered fuel and purchased power costs.

4. **Documents Reviewed**

   a. GMO's interest calculation work papers in support of the interest calculation amount on the under-recovered or over-recovered balance.

*Staff Expert: Matthew Barnes*

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of the Third Prudence<br>Review of Costs Subject to the<br>Commission-Approved Fuel Adjustment<br>Clause of KCP&L Greater Missouri<br>Operations Company | )<br>)<br>)<br>)<br>) | Case No. EO-2011-0390 |

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI )
) ss
COUNTY OF COLE )

Matthew J. Barnes, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages [illegible]; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

[illegible signature]
Matthew J. Barnes

Subscribed and sworn to before me this [illegible] day of November, 2011.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

[illegible signature]
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of the Third Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of KCP&L Greater Missouri Operations Company | ) ) ) ) ) | Case No. EO-2011-0390 |

AFFIDAVIT OF LEON C. BENDER

STATE OF MISSOURI )
) ss
COUNTY OF COLE )

Leon C. Bender, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages ______________; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Leon C. Bender

Subscribed and sworn to before me this ____ day of November, 2011.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of the Third Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of KCP&L Greater Missouri Operations Company | ) ) ) ) ) | Case No. EO-2011-0390 |

AFFIDAVIT OF DANA E. EAVES

STATE OF MISSOURI )
) ss
COUNTY OF COLE )

Dana E. Eaves, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages [illegible]; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Dana E. Eaves

Subscribed and sworn to before me this [illegible] day of November, 2011.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Notary Public

## BEFORE THE PUBLIC SERVICE COMMISSION

## OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of the Third Prudence<br>Review of Costs Subject to the<br>Commission-Approved Fuel Adjustment<br>Clause of KCP&L Greater Missouri<br>Operations Company | )<br>)<br>)<br>)<br>) | Case No. EO-2011-0390 |

### AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI )
) ss
COUNTY OF COLE )

David C. Roos, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages [illegible]; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David C. Roos

Subscribed and sworn to before me this [illegible] day of November, 2011.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Notary Public

# MATTHEW J. BARNES

## Educational and Employment Background and Credentials

I am a Regulatory Auditor IV in the Utility Operations Department, Energy Resource Analysis Section for the Missouri Public Service Commission. I accepted the position of Utility Regulatory Auditor I/II/III in June 2003. I was promoted to the position of Utility Regulatory Auditor IV in July 2008.

In December 2002, I earned a Bachelor of Science Degree in Business Administration with an Emphasis in Accounting from Columbia College. I earned a Masters in Business Administration with an Emphasis in Accounting from William Woods University in May 2005.

SUMMARY

OF

MATTHEW J. BARNES

CASE PARTICIPATION

SCHEDULE 1

| Date Filed | Issue | Case Number | Exhibit | Case Name |
|---|---|---|---|---|
| 09/08/2004 | Merger with TXU Gas | GM20040607 | Staff Recommendation | Atmos Energy Corporation |
| 10/15/2004 | Rate of Return | TC20021076 | Supplemental Direct | BPS Telephone Company |
| 06/28/2005 | Finance Recommendation | EF20050387 | Staff Recommendation | Kansas City Power and Light Company |
| 06/28/2005 | Finance Recommendation | EF20050388 | Staff Recommendation | Kansas City Power and Light Company |
| 08/31/2005 | Finance Recommendation | EF20050498 | Staff Recommendation | Kansas City Power and Light Company |
| 11/15/2005 | Spin-off of landline operations | IO20060086 | Rebuttal | Sprint Nextel Corporation |
| 03/08/2006 | Spin-off of landline operations | TM20060272 | Rebuttal | Alltel Missouri, Inc. |
| 08/08/2006 | Rate of Return | ER20060314 | Direct | Kansas City Power & Light Company |
| 09/08/2006 | Rate of Return | ER20060314 | Rebuttal | Kansas City Power & Light Company |
| 09/13/2006 | Rate of Return | GR20060387 | Direct | Atmos Energy Corporation |

SUMMARY

OF

MATTHEW J. BARNES

CASE PARTICIPATION

SCHEDULE 1

| Date Filed | Issue | Case Number | Exhibit | Case Name |
|---|---|---|---|---|
| 10/06/2006 | Rate of Return | ER20060314 | Surrebuttal | Kansas City Power & Light Company |
| 11/07/2006 | Rate of Return | ER20060314 | True-Up Direct | Kansas City Power & Light Company |
| 11/13/2006 | Rate of Return | GR20060387 | Rebuttal | Atmos Energy Corporation |
| 11/23/2006 | Rate of Return | GR20060387 | Surrebuttal | Atmos Energy Corporation |
| 12/01/2006 | Rate of Return | WR20060425 | Direct | Algonquin Water Resources of Missouri LLC |
| 12/28/2006 | Rate of Return | WR20060425 | Rebuttal | Algonquin Water Resources of Missouri LLC |
| 01/12/2007 | Rate of Return | WR20060425 | Surrebuttal | Algonquin Water Resources of Missouri LLC |
| 02/07/2007 | Finance Recommendation | GF20070220 | Staff Recommendation | Laclede Gas Company |
| 05/04/2007 | Rate of Return | GR20070208 | Direct | Laclede Gas Company |

SUMMARY

OF

MATTHEW J. BARNES

CASE PARTICIPATION

SCHEDULE 1

| Date Filed | Issue | Case Number | Exhibit | Case Name |
|---|---|---|---|---|
| 07/24/2007 | Rate of Return | ER20070291 | Direct | Kansas City Power and Light Company |
| 08/30/2007 | Rate of Return | ER20070291 | Rebuttal | Kansas City Power and Light Company |
| 09/20/2007 | Rate of Return | ER20070291 | Surrebuttal | Kansas City Power and Light Company |
| 11/02/2007 | Rate of Return | ER20070291 | True-up Direct | Kansas City Power and Light Company |
| 02/01/2008 | Finance Recommendation | EF20080214 | Staff Recommendation | Kansas City Power and Light Company |
| 02/22/2008 | Rate of Return | ER20080093 | Staff Report | The Empire District Electric Company |
| 04/04/2008 | Rate of Return | ER20080093 | Rebuttal Testimony | The Empire District Electric Company |
| 04/25/2008 | Rate of Return | ER20080093 | Surrebuttal Testimony | The Empire District Electric Company |
| 08/18/2008 | Rate of Return | WR20080311 | Staff Report | Missouri-American Water Company |
| 09/30/2008 | Rate of Return | WR20080311 | Rebuttal Testimony | Missouri-American Water Company |

SUMMARY

OF

MATTHEW J. BARNES

CASE PARTICIPATION

SCHEDULE 1

| Date Filed | Issue | Case Number | Exhibit | Case Name |
|---|---|---|---|---|
| 10 16/2008 | Rate of Return | WR2008031 | Surrebuttal Testimony | Missouri-American Water Company |
| 02 26/2010 | Fuel Adjustment Clause | ER20100130 | Staff Report | The Empire District Electric Company |
| 04 02/2010 | Fuel Adjustment Clause | ER20100130 | Rebuttal Testimony | The Empire District Electric Company |
| 04 23/2010 | Fuel Adjustment Clause | ER20100130 | Surrebuttal Testimony | The Empire District Electric Company |
| 02/23 11 | Fuel Adjustment Clause | ER20110004 | Staff Report | The Empire District Electric Company |
| 04/22 11 | Fuel Adjustment Clause | ER20110004 | Rebuttal Testimony | The Empire District Electric Company |
| 04/28 11 | Fuel Adjustment Clause | ER20110004 | Surrebuttal Testimony | The Empire District Electric Company |
| 05/06 11 | Fuel Adjustment Clause | ER20110004 | True-up Direct Testimony | The Empire District Electric Company |
| 10/21 11 | Costs for the Phase-In Tariffs | ER20120024 | Direct Testimony | KCP&L Greater Missouri Operations Company |
| 11/17 11 | Rate of Return | WR20110337 | Staff Report | Missouri-American Water Company |

Leon Bender's Creditials

I received a Bachelor of Science degree in Mechanical Engineering in August 1978 from Texas Tech University. I became employed by Southwestern Public Service Company (SPS) as a power generation plant design engineer in September 1978. While employed by SPS, I was lead engineer on many projects involving design and construction of new power generating stations and the upgrading of their older plants. In 1983, I became a registered Professional Engineer in the state of Texas. In 1986, I transferred to SPS's newly formed subsidiary company, Utility Engineering Corporation, and was responsible for various projects at various other clients' power generation plants. In June 1990, I accepted employment as a systems engineer with Entergy Operations, Inc. at the nuclear powered generating station, Arkansas Nuclear One. In December 1995, I joined the Missouri Public Service Commission (Commission). While employed by the Commission I have been responsible for determining variable fuel and purchased power cost using the production cost fuel model in numerous cases. In June 2008, I accepted employment with Kiewit Power Engineers but returned to the Commission in October 2008 where I now work in the Energy Resource Analysis section.

# List of Previously Filed Testimony for Leon Bender

| | | | |
|---|---|---|---|
| 1. | ER-2011-0317 | Union Electric Company d/b/a AmerenMissouri | FAC |
| 2. | ER-2011-0004 | The Empire District Electric Company | Rate Case |
| 3. | ER-2011-0419 | Kansas City Power & Light Company\GMO | FAC |
| 4. | EO-2011-0271 | Union Electric Company d/b/a AmerenMissouri | IRP |
| 5. | HT-2011-0343 | Kansas City Power & Light Company\GMO | QCA |
| 6. | ER-2011-0028 | Union Electric Company d/b/a AmerenMissouri | Rate Case |
| 7. | ER-2011-0095 | The Empire District Electric Company | FAC |
| 8. | ER-2011-0018 | Union Electric Company d/b/a AmerenUE | FAC |
| 9. | HT-2010-0288 | Kansas City Power & Light Company\GMO | QCA |
| 10. | ER-2010-0275 | The Empire District Electric Company | FAC |
| 11. | ER-2010-0264 | Union Electric Company d/b/a AmerenUE | FAC |
| 12. | ER-2010-0130 | The Empire District Electric Company | Rate Case |
| 13. | ER-2010-0105 | The Empire District Electric Company | FAC |
| 14. | EO-2011-0066 | The Empire District Electric Company | IRP |
| 15. | EO-2010-0255 | Union Electric Company d/b/a AmerenUE | FAC Prudence Review |
| 16. | EO-2010-0167 | Kansas City Power & Light Company\GMO | FAC Prudence Review |
| 17. | EO-2010-0167 | Kansas City Power & Light Company | FAC Prudence Review |
| 18. | EO-2010-0084 | The Empire District Electric Company | FAC Prudence Review |
| 19. | EO-2008-0915 | Kansas City Power & Light Company\GMO | FAC |
| 20. | EO-2008-0415 | Kansas City Power & Light Company\GMO | FAC |
| 21. | EE-2009-0237 | Kansas City Power & Light Company\GMO | IRP |
| 22. | EE-2008-0034 | Kansas City Power & Light Company | IRP |
| 23. | ER-2008-0093 | The Empire District Electric Company | Rate Case\Fuel Expense |
| 24. | ER-2008-089 | Kansas City Power & Light Company | Rate Case\Fuel Expense |
| 25. | ER-2007-0291 | Kansas City Power & Light Company | Rate Case\Fuel Expense |
| 26. | ER-2007-0004 | Aquila, Inc. | Rate Case\Fuel Expense |
| 27. | ER-2007-0002 | Union Electric Company d/b/a AmerenUE | Rate Case\Fuel Expense |
| 28. | ER-2006-0314 | Kansas City Power & Light Company | Rate Case\Fuel Expense |
| 29. | EA-2006-0309 | Aquila, Inc. | Rate Case\Fuel Expense |
| 30. | ER-2005-0436 | Aquila, Inc. | Rate Case\Fuel Expense |
| 31. | ER-2004-0570 | The Empire District Electric Company | Rate Case\Fuel Expense |
| 32. | ER-2004-0034 | Aquila, Inc. | Rate Case\Fuel Expense |
| 33. | EC-2002-0001 | Union Electric Company d/b/a AmerenUE | Complaint Case\Fuel Expense |
| 34. | ER-2001-0299 | The Empire District Electric Company | Rate Case\Fuel Expense |
| 35. | EM-97-0515 | Kansas City Power & Light Company | Merger Case\Fuel Expense |
| 36. | ER-97-0394 | Utilicorp United, Inc. | Rate Case\Fuel Expense |
| 37. | EC-97-0362 | Utilicorp United, Inc. | Complaint Case\Fuel Expense |

## DANA EAVES
### CAREER EXPERIENCE

**Missouri Public Service Commission, Jefferson City, Missouri**

**Utility Regulatory Auditor III** April 23, 2003– Present
**Utility Regulatory Auditor II** April, 2002 – April, 2003
**Utility Regulatory Auditor I** April, 2001 – April, 2002

Perform rate audits and prepare miscellaneous filings as ordered by the Commission. Review all exhibits and testimony on assigned issues from the most recent previous case and the current case. Develop accounting adjustments and issue positions which are supported by workpapers and written testimony. Prepare Staff Recommendation Memorandum for filings that do not require prepared testimony. Act as Lead Auditor for small to middle size rate cases and certificate cases as assigned by management. I have testified under cross-examination as an expert witness for litigated rate cases.

**Midwest Block and Brick, Jefferson City, Missouri**

**Accountant** December 2000 – March 2001
**CIS/Accounting Assistant** July 2000 – December 2000

**Practice Management Plus, Inc., Jefferson City, Missouri**

**Vice President Operations** October 1998 – May 2000

**Capital City Medical Associates (CCMA), Jefferson City, Missouri**

**Director of Finance** March, 1995-October, 1998

### ADDITIONAL EXPERIENCE

| | |
|---|---|
| Wright Camera Shop/Sales | 1987-1995 |
| Movies To Go, Inc/Store Manager | 1984-1987 |
| Butler Shoe Corp./Store Manager | 1982-1984 |
| Southeastern Illinois College/Student | 1979-1982 |
| Kassabaum's Bicycle Shop/Store Manager | 1977-1979 |

### EDUCATION

**Bachelor of Science, Business Administration; Emphasis Accounting** (1995)
COLUMBIA COLLEGE, JEFFERSON CITY, MO

## CASE PROCEEDING PARTICIPATION

### DANA E. EAVES

| PARTICIPATION | | TESTIMONY |
|---|---|---|
| COMPANY | CASE NO. | ISSUES |
| Empire District Electric Company | EO-2011-0285 | Prudency Review |
| AmerenUE | EO-2010-0255 | Prudency Review |
| Empire District Electric Company | EO-2010-0084 | Prudency Review |
| Missouri American Water Company | WR-2008-0311 | *Pension and Other Post-Retirement Employee Benefits Costs, Annual Incentive Plan Pay-out Based Upon Meeting Financial Goals and Customer Satisfaction Survey, Labor and Labor-Related Expenses, Rate Case Expenses, Insurance Other than Group, and Waste Disposal Expense* |
| Empire District Electric Company | ER-2008-0093 | Fuel and Purchased Power, Fuel Inventories, FAS 87 (pension), FAS 106 (OPEBS), Expenses and Regulatory Assets, Off System Sales, Transmission Revenue, SO2 Allowances, Maintenance Expense |
| Laclede Gas Company | GR-2007-0208 | Accounting Schedules Reconciliation |
| Empire District Electric Company | ER-2006-0315 | Direct - Jurisdictional Allocations Factors, Revenue, Uncollectible Expense, Pensions, Prepaid Pension Asset, Other Post-Employment Benefits<br>Rebuttal - Updated: Pension Expense, Updated Prepaid Pension Asset, OPEB's Tracker, Minimum Pension Liability |
| Missouri Gas Energy (Gas) | GR-2004-0209 | Direct – Cash Working Capital, Payroll, Payroll Taxes, Incentive Compensation, Bonuses, Materials and Supplies, Customer Deposits and Interest, Customer Advances and Employee Benefits<br>Surrebuttal – Incentive Compensation |

| PARTICIPATION | | TESTIMONY |
|---|---|---|
| COMPANY | CASE NO. | ISSUES |
| Aquila, Inc. d/b/a Aquila Networks-MPS & L&P (Natural Gas) | GR-2004-0072 | Direct - Payroll Expense, Employee Benefits, Payroll Taxes<br>Rebuttal – Payroll Expense, Incentive Compensation, Employer Health, Dental and Vision Expense |
| Aquila, Inc. d/b/a Aquila Networks-MPS (Electric) | ER-2004-0034 | Direct - Payroll Expense, Employee Benefits, Payroll Taxes<br>Rebuttal – Payroll Expense, Incentive Compensation, Employer Health, Dental and Vision Expense |
| Aquila, Inc. d/b/a Aquila Networks-L&P (Electric & Steam) | HR-2004-0024 | Direct - Payroll Expense, Employee Benefits, Payroll Taxes |
| Osage Water Company | ST-2003-0562<br>WT-2003-0563 | Direct - Plant Adjustment, Operating & Maintenance Expense Adjustments |
| Empire District Electric Company | ER-2002-0424 | Direct - Cash Working Capital, Property Tax, Tree Trimming, Injuries and Damages, Outside Services, Misc. Adjustments |
| Citizens Electric Corporation | ER-2002-0297 | Direct - Depreciation Expense, Accumulated Depreciation, Customer Deposits, Material & Supplies, Prepayments, Property Tax, Plant in Service, Customer Advances in Aid of Construction |
| UtiliCorp United Inc. d/b/a Missouri Public Service | ER-2001-672 | Direct - Advertising, Customer Advances, Customer Deposits, Customer Deposit Interest Expense, Dues and Donations, Material and Supply, Prepayments, PSC Assessment, Rate Case Expense |

## PROCEEDING PARTICIPATION

### DANA E. EAVES

### Schedule 2

| PARTICIPATION – No direct testimony filed or NON-Case (Informal) proceeding | | |
|---|---|---|
| **COMPANY** | **CASE or Tracking No.** | **ISSUES** |
| RDG Sanitation | SA-2010-0096 | Certificate Case |
| Mid Mo Sanitation | SR-2009-0153 | Informal General Rate Case |
| Highway H Utilities, Inc. | SR-2009-0392<br>and<br>WR-2009-0393 | Informal General Rate Case |
| Osage Water Company | SR-2009-0149<br>WR-2009-0152 | General Rate Case<br>Lead Auditor |
| Hickory Hills | SR-2009-0151<br>WR-2009-0154 | General Rate Case<br>Lead Auditor |
| Missouri Utilities | SR-2009-0153<br>WR-2009-0150 | General Rate Case<br>Lead Auditor |
| Roy L. Utilities | QS-2008-0001<br>and<br>QW-2008-0002 | General Informal Rate Case |
| III Utilities, Inc. | QW-2007-0003 | General Rate Case |
| W.P.C. Sewer Company | QS-2007-0005 | Rate Case<br>Lead Auditor |
| West 16th Street Sewer Company, Inc. | QS-2007-0004 | Rate Case<br>Lead Auditor |

| PARTICIPATION – No direct testimony filed or NON-Case (Informal) proceeding | | |
|---|---|---|
| COMPANY | CASE or Tracking No. | ISSUES |
| Gladlo Water & Sewer Company, Inc. | QS-2007-0001 and QW-2007-0002 | Rate Case<br>Lead Auditor<br>Supervised: Kofi Boateng |
| Taneycomo Highlands, Inc. | QS-2006-0004 | Rate Case<br>Lead Auditor |
| Empire District Electric | QW-2005-0013 | Informal General Rate Case |
| Cass County Telephone Company | TO-2005-0237 | Cash Flow Analysis, LEC Invoices, Bank Reconciliations, Expense Analysis |
| LTA Water Company | WM-2005-0058 | Merger Case with Missouri American<br>Main Issue: Plant Valuation<br>Lead Auditor |
| Noel Water Company, Inc. | QW-2005-0002 | Rate Case<br>Lead Auditor<br>Supervised: Kofi Boateng |
| Suburban Water and Sewer Company, Inc. | QW-2005-0001 | Rate Case<br>Lead Auditor<br>Supervised: Kofi Boateng |
| Osage Water Company | WC-2003-0134 | Customer Refund Review |
| Noel Water Company, Inc. | QW-2003-0022 | Rate Case<br>Lead Auditor<br>Supervised: Trisha Miller |
| AquaSource | WR-2003-0001 and SR-2003-0002 | Plant in Service, Construction Work in Progress, Payroll, Depreciation Expense |
| Warren County Water and Sewer Company | WC-2002-155 | General |
| Environmental Utilities, LLC | WA-2002-65 | General |
| Meadows Water Company | WR-2001-966 and SR-2001-967 | Expense Items |

David C. Roos

**Present Position:** I am a Regulatory Economist III in the Energy Resource Analysis Section, Energy Department, Operations Division of the Missouri Public Service Commission.

**Educational Background and Work Experience:**

In May 1983, I graduated from the University of Notre Dame, Notre Dame, Indiana, with a Bachelor of Science Degree in Chemical Engineering. I also graduated from the University of Missouri in December 2005, with a Master of Arts in Economics. I have been employed at the Missouri Public Service Commission as a Regulatory Economist III since March 2006. Prior to joining the Public Service Commission I taught introductory economics and conducted research as a graduate teaching assistant and graduate research assistant at the University of Missouri. Prior to the University of Missouri, I was employed by several private firms where I provided consulting, design, and construction oversight of environmental projects for private and public sector clients.

**Previous Cases**

| Company | Case No. |
|---|---|
| Empire District Electric Company | ER-2006-0315 |
| AmerenUE | ER-2007-0002 |
| Aquila Inc. | ER-2007-0004 |
| Kansas City Power and Light | ER-2007-0291 |
| AmerenUE | EO-2007-0409 |
| Empire District Electric Company | ER-2008-0093 |
| Kansas City Power and Light | ER-2008-0034 |
| Greater Missouri Operations | HR-2008-0340 |
| Greater Missouri Operations | ER-2009-0091 |
| Greater Missouri Operations | EO-2009-0115 |
| Greater Missouri Operations | EE-2009-0237 |
| Greater Missouri Operations | EO-2009-0431 |
| Empire District Electric Company | ER-2010-0105 |

| | |
|---|---|
| Greater Missouri Operations | EO-2010-0002 |
| AmerenUE | ER-2010-0036 |
| AmerenUE | ER-2010-0044 |
| Empire District Electric Company | EO-2010-0084 |
| Empire District Electric Company | ER-2010-0105 |
| AmerenUE | ER-2010-0165 |
| Greater Missouri Operations | EO-2010-0167 |
| AmerenUE | EO-2010-0255 |
| Greater Missouri Operations (Aquila) | EO-2008-0216 |
| Ameren Missouri | ER-2011-0028 |
| Empire District Electric Company | EO-2011-0066 |
| Empire District Electric Company | EO-2011-0285 |


Schedule 1-47

Attachment 1

Is Deemed

Highly Confidential

In Its Entirety

Schedule DEE-2

Is Deemed

Highly Confidential

In Its Entirety

## CASE PROCEEDING PARTICIPATION

### DANA E. EAVES

| PARTICIPATION | | TESTIMONY |
|---|---|---|
| **COMPANY** | **CASE NO.** | **ISSUES** |
| AmerenUE | EO-2010-0255 | Prudency Review |
| Empire District Electric Company | EO-2010-0084 | Prudency Review |
| Missouri American Water Company | WR-2008-0311 | *Pension and Other Post-Retirement Employee Benefits Costs, Annual Incentive Plan Pay-out Based Upon Meeting Financial Goals and Customer Satisfaction Survey, Labor and Labor-Related Expenses, Rate Case Expenses, Insurance Other than Group, and Waste Disposal Expense* |
| Empire District Electric Company | ER-2008-0093 | Fuel and Purchased Power, Fuel Inventories, FAS 87 (pension), FAS 106 (OPEBS), Expenses and Regulatory Assets, Off System Sales, Transmission Revenue, SO2 Allowances, Maintenance Expense |
| Laclede Gas Company | GR-2007-0208 | Accounting Schedules Reconciliation |
| Empire District Electric Company | ER-2006-0315 | Direct - Jurisdictional Allocations Factors, Revenue, Uncollectible Expense, Pensions, Prepaid Pension Asset, Other Post-Employment Benefits<br>Rebuttal - Updated: Pension Expense, Updated Prepaid Pension Asset, OPEB's Tracker, Minimum Pension Liability |
| Missouri Gas Energy (Gas) | GR-2004-0209 | Direct – Cash Working Capital, Payroll, Payroll Taxes, Incentive Compensation, Bonuses, Materials and Supplies, Customer Deposits and Interest, Customer Advances and Employee Benefits<br>Surrebuttal – Incentive Compensation |

| PARTICIPATION | | TESTIMONY |
|---|---|---|
| **COMPANY** | **CASE NO.** | **ISSUES** |
| Aquila, Inc. d/b/a Aquila Networks-MPS & L&P (Natural Gas) | GR-2004-0072 | Direct - Payroll Expense, Employee Benefits, Payroll Taxes<br>Rebuttal – Payroll Expense, Incentive Compensation, Employer Health, Dental and Vision Expense |
| Aquila, Inc. d/b/a Aquila Networks-MPS (Electric) | ER-2004-0034 | Direct - Payroll Expense, Employee Benefits, Payroll Taxes<br>Rebuttal – Payroll Expense, Incentive Compensation, Employer Health, Dental and Vision Expense |
| Aquila, Inc. d/b/a Aquila Networks-L&P (Electric & Steam) | HR-2004-0024 | Direct - Payroll Expense, Employee Benefits, Payroll Taxes |
| Osage Water Company | ST-2003-0562<br>WT-2003-0563 | Direct - Plant Adjustment, Operating & Maintenance Expense Adjustments |
| Empire District Electric Company | ER-2002-0424 | Direct - Cash Working Capital, Property Tax, Tree Trimming, Injuries and Damages, Outside Services, Misc. Adjustments |
| Citizens Electric Corporation | ER-2002-0297 | Direct - Depreciation Expense, Accumulated Depreciation, Customer Deposits, Material & Supplies, Prepayments, Property Tax, Plant in Service, Customer Advances in Aid of Construction |
| UtiliCorp United Inc. d/b/a Missouri Public Service | ER-2001-672 | Direct - Advertising, Customer Advances, Customer Deposits, Customer Deposit Interest Expense, Dues and Donations, Material and Supply, Prepayments, PSC Assessment, Rate Case Expense |
| Ameren Missouri | EO-2012-0074 | Prudency Review |

# PROCEEDING PARTICIPATION

## DANA E. EAVES

### Schedule 2

| PARTICIPATION – No direct testimony filed or NON Case (Informal) proceeding | | |
|---|---|---|
| COMPANY | CASE or Tracking No. | ISSUES |
| RDG Sanitation | SA-2010-0096 | Certificate Case |
| Mid Mo Sanitation | SR-2009-0153 | Informal General Rate Case |
| Highway H Utilities, Inc. | SR-2009-0392 and WR-2009-0393 | Informal General Rate Case |
| Osage Water Company | SR-2009-0149 WR-2009-0152 | General Rate Case Lead Auditor |
| Hickory Hills | SR-2009-0151 WR-2009-0154 | General Rate Case Lead Auditor |
| Missouri Utilities | SR-2009-0153 WR-2009-0150 | General Rate Case Lead Auditor |
| Roy L. Utilities | QS-2008-0001 and QW-2008-0002 | General Informal Rate Case |
| HI Utilities, Inc. | QW-2007-0003 | General Rate Case |
| W.P.C. Sewer Company | QS-2007-0005 | Rate Case Lead Auditor |
| West 16th Street Sewer Company, Inc. | QS-2007-0004 | Rate Case Lead Auditor |

| PARTICIPATION – No direct testimony filed or NON-Case (Informal) proceeding | | |
|---|---|---|
| **COMPANY** | **CASE or Tracking No.** | **ISSUES** |
| Gladlo Water & Sewer Company, Inc. | QS-2007-0001 and QW-2007-0002 | Rate Case<br>Lead Auditor<br>Supervised: Kofi Boateng |
| Taneycomo Highlands, Inc. | QS-2006-0004 | Rate Case<br>Lead Auditor |
| Empire District Electric | QW-2005-0013 | Informal General Rate Case |
| Cass County Telephone Company | TO-2005-0237 | Cash Flow Analysis, LEC Invoices, Bank Reconciliations, Expense Analysis |
| LTA Water Company | WM-2005-0058 | Merger Case with Missouri American<br>Main Issue: Plant Valuation<br>Lead Auditor |
| Noel Water Company, Inc. | QW-2005-0002 | Rate Case<br>Lead Auditor<br>Supervised: Kofi Boateng |
| Suburban Water and Sewer Company, Inc. | QW-2005-0001 | Rate Case<br>Lead Auditor<br>Supervised: Kofi Boateng |
| Osage Water Company | WC-2003-0134 | Customer Refund Review |
| Noel Water Company, Inc. | QW-2003-0022 | Rate Case<br>Lead Auditor<br>Supervised: Trisha Miller |
| AquaSource | WR-2003-0001 and SR-2003-0002 | Plant in Service, Construction Work in Progress, Payroll, Depreciation Expense |
| Warren County Water and Sewer Company | WC-2002-155 | General |
| Environmental Utilities, LLC | WA-2002-65 | General |
| Meadows Water Company | WR-2001-966 and SR-2001-967 | Expense Items |

FUEL ADJUSTMENT CLAUSE
ELECTRIC

## DEFINITIONS

ACCUMULATION PERIOD:

The two six-month accumulation periods each year through May 31, 2011, the two corresponding twelve-month recovery periods and filing dates will be as follows:

| Accumulation Period | Filing Date | Recovery Period |
|---|---|---|
| June – November | By January 1 | March – February |
| December – May | By July 1 | September – August |

RECOVERY PERIOD:

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

COSTS:

Costs eligible for Fuel Adjustment Clause (FAC) will be the Company's allocated variable Missouri Jurisdictional costs for the fuel component of the Company's generating units, purchased power energy charges, and emission allowance costs. Eligible costs do not include the purchased power demand costs associated with purchased power contracts.

## APPLICATION

The price per kWh of electricity sold will be adjusted subject to application of the FAC mechanism and approval by the Missouri Public Service Commission. The price will reflect accumulation period Missouri Jurisdictional costs above or below base costs for:

1. variable fuel components related to the Company's electric generating plants;
2. purchased power energy charges;
3. emission allowance costs;
4. an adjustment for recovery period sales variation. This is based on the difference between the values of the FAC as adjusted minus actual FAC revenue during the recovery period. This amount will be collected or refunded during a succeeding recovery period;
5. interest on deferred electric energy costs, which shall be determined monthly. Interest shall be calculated at a rate equal to the weighted average interest rate paid on short-term debt, applied to the month-end balance of deferred electric energy costs. The accumulated interest shall be included in the determination of the CAF.

The FAC will be the aggregation of (1), (2), (3), minus the base cost of fuel, all times 95%, plus or minus (4), plus (5), above.

The Cost Adjustment Factor is the result of dividing the FAC by estimated kWh sales during the recovery period, rounded to the nearest $.0001, and aggregating over two accumulation periods. The formula and components are displayed below.

Schedule DEE-5-1

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

P.S.C. MO. No. 1 Original Sheet No. 125

Canceling P.S.C. MO. No. Sheet No.

Aquila, Inc., dba

AQUILA NETWORKS For All Territory Served by Aquila Networks – L&P and Aquila Networks – MPS

KANSAS CITY, MO 64138

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC

$$FAC_{Sec} = \{[95\% * (F + P + E - B)] * \{(S_{ASec} * L_{Sec}) / [(S_{ASec} * L_{Sec}) + (S_{APrim} * L_{Prim})]\}\} + C_{Sec}$$

$$FAC_{Prim} = \{[95\% * (F + P + E - B)] * \{(S_{APrim} * L_{Prim}) / [(S_{ASec} * L_{Sec}) + (S_{APrim} * L_{Prim})]\}\} + C_{Prim}$$

The Cost Adjustment Factor (CAF) is as follows:

Single Accumulation Period Secondary Voltage CAF = $FAC_{Sec} / S_{RSec}$

Single Accumulation Period Primary Voltage CAF = $FAC_{Prim} / S_{RPrim}$

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

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

Where:

$FAC_{Sec}$ = Secondary Voltage FAC
$FAC_{Prim}$ = Primary Voltage FAC
95% = Customer responsibility for fuel variance from base level
F = Actual variable cost of fuel in FERC Accounts 501 & 547
P = Actual cost of purchased energy in FERC Account 555
E = Actual emission allowance cost in FERC Account 509
B = Base variable fuel costs, purchased energy, and emission allowances are calculated as shown below:
Aquila Networks – L&P $S_A$ x $0.01799
Aquila Networks – MPS $S_A$ x $0.02538
C = Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications due to prudence reviews
$C_{Sec}$ = Lower than Primary Voltage Customers
$C_{Prim}$ = Primary and Higher Voltage Customers
$S_A$ = Actual sales (kWh) for the accumulation period
$S_{ASec}$ = Lower than Primary Voltage Customers
$S_{APrim}$ = Primary and Higher Voltage Customers
$S_R$ = Estimated sales (kWh) for the recovery period
$S_{RSec}$ = Lower than Primary Voltage Customers
$S_{RPrim}$ = Primary and Higher Voltage Customers
L = Loss factor by voltage level
$L_{Sec}$ = Lower than Primary Customers
$L_{Prim}$ = Primary and Higher Customers

Schedule DEE-5-2

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC

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

APPLICABLE BASE ENERGY COST

Company base energy cost per kWh sold, $0.01799 for Aquila Networks – L&P, and $0.02538 for Aquila Networks – MPS.

TRUE-UPS AND PRUDENCE REVIEWS

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

Schedule DEE-5-3

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

| | | | |
|---|---|---|---|
| P.S.C. MO. No. 1 | 3rd | Revised Sheet No. | 127 |
| Canceling P.S.C. MO. No. 1 | 2nd | Revised Sheet No. | 127 |

**KCP&L Greater Missouri Operations Company**
**(for all territories formerly served by Aquila Networks, Inc. – L&P and MPS)**
KANSAS CITY, MO 64106

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC

COST ADJUSTMENT FACTOR

| Aquila Networks – L&P | | Total | | Secondary | | Primary |
|---|---|---|---|---|---|---|
| Accumulation Period Ending | | 11/30/08 | | | | |
| 1 Total energy cost (F, P, and E) | | $24,933,313 | | | | |
| 2 Base energy cost (B) | - | $18,498,700 | | | | |
| 3 First Interim Total | | $6,434,614 | | | | |
| 4 Base energy ($S_A$) by voltage level | | | | 877,271,542 | | 151,005,258 |
| 4.1 Loss factors (L) | | | * | 108.443% | * | 106.231% |
| 4.2 $S_A$ adjusted for losses | | | | 951,341,054 | | 160,414,874 |
| 4.3 Loss factor weights | | | * | 85.571% | * | 14.429% |
| 5 Customer Responsibility | * | 95% | | | | |
| 6 Second Interim Total by voltage level | | $6,112,883 | | $5,230,857 | | $882,026 |
| 7 Adjustment for Under / Over recovery for prior periods (C) | | | ± | $0 | ± | $0 |
| 8 Fuel Adjustment Clause | | | | $5,299,700 | | $893,876 |
| 9 Estimated recovery period sales kWh ($S_R$) | | | ÷ | 1,863,031,338 | ÷ | 320,684,662 |
| 10 Current period cost adjustment factor | | | | $0..0028 | | $0.0028 |
| 11 Previous period cost adjustment factor | | | + | $0.0008 | + | $0.0008 |
| 12 Current annual cost adjustment factor | | | | $0.0036 | | $0.0036 |

| Aquila Networks – MPS | | Total | | Secondary | | Primary |
|---|---|---|---|---|---|---|
| Accumulation Period Ending | | 11/30/08 | | | | |
| 1 Total energy cost (F, P, and E) | | $95,433,447 | | | | |
| 2 Base energy cost (B) | - | $76,374,769 | | | | |
| 3 First Interim Total | | $19,058,678 | | | | |
| 4 Base energy ($S_A$) by voltage level | | | | 2,589,516,360 | | 419,733,793 |
| 4.1 Loss factors (L) | | | * | 107.433% | * | 104.187% |
| 4.2 $S_A$ adjusted for losses | | | | 2,781,994,192 | | 437,307,885 |
| 4.3 Loss factor weights | | | * | 86.416% | * | 13.584% |
| 5 Customer Responsibility | * | 95% | | | | |
| 6 Second Interim Total by voltage level | | $18,105,744 | | $15,646,272 | | $2,459,472 |
| 7 Adjustment for Under / Over recovery for prior periods (C) | | | ± | $0 | ± | $0 |
| 8 Fuel Adjustment Clause | | | | $16,182,699 | | $2,546,422 |
| 9 Estimated recovery period sales kWh ($S_R$) | | | ÷ | 5,235,810,348 | ÷ | 848,670,652 |
| 10 Current period cost adjustment factor | | | | $0.0031 | | $0.0030 |
| 11 Previous period cost adjustment factor | | | + | $0.0023 | + | $0.0022 |
| 12 Current annual cost adjustment factor | | | | $0.0054 | | $0.0052 |



Schedule DEE-5-4

Issued: December 30, 2008 Effective: March 1, 2009
Issued by: Tim Rush, Regulatory Affairs

FUEL ADJUSTMENT CLAUSE ELECTRIC
(Applicable to Service Provided September 1, 2009 and Thereafter)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

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

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

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

COSTS AND REVENUES:

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

APPLICABILITY

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

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

Schedule DEE-6-1

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided September 1, 2009 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((TEC – B) * J) + C + I

CAF = FPA/RNSI

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

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

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

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

Where:

FPA = Fuel and Purchased Power Adjustment

CAF = Cost Adjustment Factor

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

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

FC = Fuel Costs Incurred to Support Sales:

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

Schedule DEE-6-2

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided September 1, 2009 and Thereafter)

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

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

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

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

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

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

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

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

Schedule DEE-6-3

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided September 1, 2009 and Thereafter)

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

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

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

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

APPLICABLE BASE ENERGY COST

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

TRUE-UPS AND PRUDENCE REVIEWS

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

Schedule DEE-6-4

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided September 1, 2009 and Thereafter)

COST ADJUSTMENT FACTOR

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

Expansion Factors (XF):

| Network: | Primary | Secondary |
|---|---|---|
| MPS | 1.0444 | 1.0679 |
| L&P | 1.0444 | 1.0700 |

CANCELLED
March 1, 2011
Missouri Public
Service Commission
ER-2010-0356; JE-2010-0410

Schedule DEE-6-5

Issued: July 8, 2009 Effective: September 1, 2009
Issued by: Curtis D. Blanc, Sr. Director

FILED
Missouri Public
Service Commission
ER-2009-0090; YE-2010-001(

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided September 1, 2009 and Thereafter)

COST ADJUSTMENT FACTOR

| | | MPS (1) | L&P (1) |
|---|---|---|---|
| Accumulation Period Ending | | 11/30/09 | 11/30/09 |
| 1 Total Energy Cost (TEC) | | | |
| 2 Base energy cost (B) | - | | |
| 3 First Interim Total | | | |
| 4 Jurisdictional Factor (J) | * | | |
| 5 Second Interim Total | | | |
| 6 Customer Responsibility | * | 95% | 95% |
| 7 Third Interim Total | | | |
| 8 Adjustment for Under / Over recovery for prior periods and Modifications due to prudence reviews (C) | + | | |
| 9 Interest (I) | + | | |
| 10 Fuel and Purchased Power Adjustment (FPA) | | | |
| 11 RNSI | ÷ | | |
| 12 Fourth Interim Total | | | |
| 13 Current period $CAF_{Prim}$ (= Line 12 * $XF_{Prim}$) | | $0.0038 | $0.0008 |
| 14 Previous period $CAF_{Prim}$ | + | $0.0032 | $0.0004 |
| 15 Current annual $CAF_{Prim}$ | | $0.0070 | $0.0012 |
| 16 Current period $CAF_{Sec}$ (= Line 12 * $XF_{Sec}$) | | $0.0038 | $0.0008 |
| 17 Previous period $CAF_{Sec}$ | + | $0.0033 | $0.0004 |
| 18 Current annual $CAF_{Sec}$ | | $0.0071 | $0.0012 |

Expansion Factors (XF):

| Network: | Primary | Secondary |
|---|---|---|
| MPS | 1.0444 | 1.0679 |
| L&P | 1.0444 | 1.0700 |

(1) The base rate and calculation to determine the CAF changed September 1, 2009 in Case No. ER-2009-0090. The current CAF calculation thus includes two different computations. The details of the calculations are included on supporting workpapers.

Schedule DEE-6-6

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided September 1, 2009 and Thereafter)

COST ADJUSTMENT FACTOR

| | | MPS | L&P |
|---|---|---|---|
| Accumulation Period Ending | | 5/31/10 | 5/31/10 |
| 1 Total Energy Cost (TEC) | | $90,226,379 | $22,334,031 |
| 2 Base energy cost (B) | - | $74,249,464 | $19,644,937 |
| 3 First Interim Total | | $15,976,915 | $2,689,094 |
| 4 Jurisdictional Factor (J) | * | 99.448% | 100% |
| 5 Second Interim Total | | $15,888,721 | $2,689,094 |
| 6 Customer Responsibility | * | 95% | 95% |
| 7 Third Interim Total | | $15,094,285 | $2,554,639 |
| 8 Adjustment for Under / Over recovery for prior periods and Modifications due to prudence reviews (C) | + | $768,873 | $377,151 |
| 9 Interest (I) | + | $421,355 | $41,847 |
| 10 Fuel and Purchased Power Adjustment (FPA) | | $16,284,513 | $2,973,638 |
| 11 RNSI | ÷ | 6,358,211,651 | 2,254,414,809 |
| 12 Fourth Interim Total | | $0.0026 | $0.0013 |
| 13 Current period $CAF_{Prim}$ (= Line 12 * $XF_{Prim}$) | | $0.0027 | $0.0014 |
| 14 Previous period $CAF_{Prim}$ | + | $0.0038 | $0.0008 |
| 15 Current annual $CAF_{Prim}$ | | $0.0065 | $0.0022 |
| 16 Current period $CAF_{Sec}$ (= Line 12 * $XF_{Sec}$) | | $0.0027 | $0.0014 |
| 17 Previous period $CAF_{Sec}$ | + | $0.0038 | $0.0008 |
| 18 Current annual $CAF_{Sec}$ | | $0.0065 | $0.0022 |

Expansion Factors (XF):

| Network: | Primary | Secondary |
|---|---|---|
| MPS | 1.0444 | 1.0679 |
| L&P | 1.0444 | 1.0700 |

Schedule DEE-6-7

**PROJECT NO. 21409**

| | | |
|---|---|---|
| **RULEMAKING RELATING TO PRICE TO BEAT** | § <br> § <br> § | **PUBLIC UTILITY COMMISSION <br><br> OF TEXAS** |

**ORDER ADOPTING §25.41 RELATING TO PRICE TO BEAT**

The Public Utility Commission of Texas (commission) adopts new §25.41 relating Price to Beat with changes to the proposed text as published in the November 10, 2000 *Texas Register* (25 TexReg 11213). This section implements the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §39.202 and §39.406 (Vernon 1998, Supplement 2001) as these sections of PURA relate to the regulation of the price to be offered by affiliated retail electric providers (REPs) for the five year period succeeding the implementation of retail choice. This section was adopted under Project Number 21409.

This section is necessary to establish the calculation methodology and other requirements under which the price to beat (PTB) will be established and administered by affiliated REPs. The commission believes that the 6.0% rate reduction embodied in Senate Bill 7, 76th Legislative Session, is an integral part of the restructuring process in Texas. However, the commission is cognizant of the experiences in other states. Where default services have not been reflective of the market prices of electricity for some or all of the months in a year, the development of a robust market has been largely stunted. Many retail customers who switched providers have returned to the default service during summer months, and in some cases, on a more permanent basis.

In the rule as adopted, the existing base rate structure will be maintained for price to beat rates and each rate component will be reduced by 6.0%. Affiliated REPs will be required to offer a price to beat for each rate and service rider for which a price to beat customer was taking service on January 1, 1999, unless otherwise approved by the commission.

The rule also prescribes how the initial fuel factor portion of the price to beat will be set in accordance with PURA §39.202(b) and permits an affiliated REP to request a seasonal fuel factor for small commercial customers. For residential customers, the rule retains the structure for the fuel factor that currently exists for the integrated utility. The commission finds that imparting seasonality to the fuel factor as provided in the rule should be the only remedy available for affiliated REPs to address potential gaming of the price to beat. The commission has determined that other suggested mechanisms to address the gaming potential such as minimum contract terms if a customer returns to the PTB, seasonal rates only upon return to the PTB, or tracking accounts that effectively pass through market prices to PTB customers (i.e., the TXU seasonal adjustment mechanism (SAM)) should not be adopted because they create significant disincentives for customers to test the competitive market.

The obligation to offer the price to beat expires at the end of 60 months after the beginning of competition. The affiliated REP may also not offer rates other than the price to beat rates for residential or small commercial customers until the earlier of 36 months after competition begins, or when 40% of the residential or small commercial load served by the affiliated transmission and distribution utility prior to customer choice is served by non-affiliated REPs. This section, as adopted, establishes the methodology for calculating the 40% threshold for each class.

This section also establishes procedures under which the fuel factor portion of the price to beat may be adjusted for changes in the prices of natural gas and electricity in the market, in accordance with PURA. The adjustment mechanism for natural gas prices is based on a percentage change in average forward gas prices from the gas prices used in setting the seasonal final fuel factors that will be effective beginning January 1, 2002. As adopted, this section provides for a minimum 4.0% materiality threshold before the fuel factors may be adjusted. Under this standard, if the percentage change in gas prices exceeds 4.0%, then the affiliated REP may petition to adjust the seasonal fuel factor by percentage equal to the change in gas prices. The rule also establishes a benchmark for "headroom" under the price to beat based on the average of the price of a three year contract for full requirements service for price to beat customers and the most recent average 12 month forward prices received for baseload capacity auction products required to be auctioned by Substantive Rule §25.381 of this title (relating to Capacity Auctions). An affiliated REP will also be allowed to adjust the fuel factor portion of the price to beat if the amount of headroom under the price to beat decreases. The combination of these two adjustments is intended to ensure that the price to beat does not become a below market rate where it is initially above market, or become further below market in the event that the price to beat is initially a below market rate in a particular area. The ability of the affiliated REP to make these adjustments will aid in the development of a robust retail market. Furthermore, the use of one and three year forward power prices is intended to strongly encourage REPs to manage wholesale price volatility through the use of longer term contracts and other hedging tools.

Additionally, the commission finds that it is appropriate, after a sufficiently liquid electricity commodity index has developed in an affiliated REP's power region and the power generation company (PGC) affiliated with the affiliated REP has finalized its stranded cost determination and non-bypassable charges or credits, as appropriate, to allow affiliated REPs to request a change to their fuel factor in order to reflect changes in the price of purchased energy indicated by this index. It is not appropriate to move to such an index until the stranded costs of the affiliated PGC are finalized as any stranded cost charges (or credits to return prior stranded cost collection) will not be finalized until stranded costs are finalized. At that time, if the price to beat for an affiliated REP is in danger of being below market because of high market prices for generation, the return of any excess mitigation, or negative stranded costs if the commission determines that it has the authority to require the return of negative stranded costs, can be used to address concerns about headroom and thereby mitigate the effects of high market prices on price to beat customers. Subsection (g)(1)(F) has been added to allow for this transition and prescribes these preconditions and the method by which an affiliated REP must transition to the use of an electricity index.

This section also establishes criteria for determining whether or not a customer is eligible for price to beat service. Under the rule, all residential customers and small commercial customers with a peak demand of less than 1,000 kilowatts are eligible for the price to beat. If a customer's peak demand exceeds 1,000 kilowatts, the customer is no longer eligible for price to beat service. However, a customer may be eligible again if the customer's peak demand does not exceed 1,000 kilowatts for a period of 12 consecutive months.

Public hearings on the proposed section were held at commission offices on January 11, 2001 at 9:30 a.m. and January 22, 2001 at 1:00 p.m. Representatives from the Alliance for Retail Markets (ARM) (whose members include Green Mountain Energy, AES New Energy, Inc., Exelon Corporation, Strategic Energy, Enron Energy Services and the New Power Company), American Association of Retired Persons (AARP), American Electric Power Company (AEP), the City of Amarillo (Amarillo), the City of Dallas (Dallas), Cities served by TXU (Cities), Consumers Union, Texas Legal Services Center (TLSC), and Texas Ratepayers to Save Energy (collectively referred to as Consumer Commenters), Office of Public Utility Counsel (OPC), Reliant Energy, Inc. (Reliant), Shell Energy Services Company, LLC (Shell), Spectrum Energy (Spectrum), the State of Texas (State), True North, and TXU Energy Services Company (TXU REP) attended the January 11 hearing and provided comments. To the extent that these comments differ from the submitted written comments, such comments are summarized herein.

Representatives from ARM, AEP, Consumers Union, Entergy Gulf States, Inc., on behalf of its retail business (Entergy REP), OPC, Reliant, Texas-New Mexico Power Company (TNMP), and TXU

REP attended the January 22 hearing and provided comments. To the extent that these comments differ from the submitted written comments, such comments are summarized herein.

Initial comments were filed on December 11, 2000, by ARM, AEP, Cities, City of Houston and Coalition of Cities (Coalition of Cities), Consumer Commenters, El Paso Electric Company (EPE), the Electric Reliability Council of Texas (ERCOT), Entergy REP, OPC, Reliant, Shell, Southwestern Public Service Company (SPS), TNMP, and TXU REP. CLECO ConnexUS also supported the ARM comments.

Reply comments were filed on January 2, 2001, by ARM, AEP, Cities, Coalition of Cities, Consumer Commenters, Entergy REP, OPC, Reliant, REP Coalition (whose members include Reliant Energy, TXU Energy Services and ARM), Shell, TNMP, and TXU REP.

Others commenting on the rule were AARP, Dallas, and Spectrum.

In the preamble to the proposed rule, the commission posed the following questions:

*Question 1: Is the use of the NYMEX natural gas price index referenced in subsection (f)(3) appropriate for the establishment of two seasonal fuel factors? If not, what mechanism should* *be included in the rule to appropriately reflect the different cost of power in summer and non-summer months?*

Several commenters, including Consumer Commenters, Cities, OPC and TXU REP were opposed to the establishment of seasonal fuel factors in general. The Consumer Commenters and TXU REP expressed concern that seasonal fuel factors will alter the existing rate structure of price to beat customers and that altering the rate structure of the price to beat violates PURA and is contrary to the intent of the legislature. TXU REP stated that Senate Bill 7, 76th Legislative Session (SB7) does not require that price to beat rates precisely track the affiliated REP's power costs or that affiliated REP's transfer variations between summer and winter wholesale power prices to retail customers. TXU REP asserted that the seasonal rates resulting from the proposed rule would punish customers, creating the kind of rate crisis that San Diego customers experienced in the summer of 2000.

Entergy REP disputed TXU REP's assertion that Texans will experience monthly market based prices akin to customers in San Diego. Under the proposed rule, Entergy REP stated that the initial seasonal fuel factors in Texas will be cost-based. Once set, the initial factors may be adjusted for changes in fuel prices. In contrast, according to Entergy REP, in San Diego, monthly electric power exchange prices were automatically passed through directly to customers.

Consumer Commenters opposed the seasonal fuel factors and the use of any index to establish the amount of those fuel factors. Additionally, Consumer Commenters argued that Senate SB 7 requires the commission to update utilities' current fuel factors, which do not contain a seasonal differential. Consumer Commenters asserted that PURA §39.202(b) requires the commission to determine the fuel factor for each utility as of December 1, 2001, and that this directive leaves no room for redefining the fuel factor. Consumer Commenters concluded that any change in the fuel factor should be applied as it is today and must be made in a commission fuel reconciliation proceeding. Consumer Commenters expressed concerns about deregulation in other states, including California, that the competitive providers have not been able to offer lower prices to the consumers as they had promised, and that in Texas the only way to raise the price to beat is through a fuel adjustment. Additionally, Consumer Commenters expressed concern over the possibility that while the affiliated REP may be losing money, its parent company would be making money on the sale of power or using its corporate structure in some way to disadvantage the affiliated REP's customers. As such, Consumer Commenters argued that affiliated REPs should be given strong incentives to hedge their risk, and that if they do not they should not be rewarded by getting an increase in the price to beat rate.

TXU REP stated that the commission should not set two or any number of seasonal fuel factors because this approach is punitive to customers, is not contemplated by the price to beat provisions in PURA and is unnecessary since residential and small commercial customers are unlikely to engage in gaming activities anyway. TXU REP commented that retail price to beat rates to customers were never intended to track costs by month or by season and that no compelling arguments in favor of such treatment have been advanced by other commenters. TXU REP noted that the advocates for seasonal factors are the new non-affiliated REPs like Shell and members of ARM who recognize that an artificial change in summer rates will drive customers away from the affiliated REPs which will benefit non-affiliated REPs.

Consumer Commenters contended that there is currently no summer-winter differential in the existing fuel factors of investor-owned utilities in Texas. Therefore, they concluded, that the most appropriate mechanism to reflect summer-winter differentials would be the opportunity for affiliated REPs to request appropriate adjustments to their fuel factors based on significant increases in the cost of fuel. Several commenters observed that the implementation of seasonal fuel factors where they are not currently in place may have the effect of increasing the total price per kilowatt hour (kWh) in the summer season, which would be inconsistent with the provisions of PURA Chapter 39. AEP stated that this effect is unlikely to result for the AEP companies, since they already have seasonal fuel factors that reflect the higher average cost of generation in the summer months. AEP suggested that concerns about the potential for monthly price increases should be addressed in the proposed rule by making the requirement for a seasonal differential optional. AEP also suggested that affiliated REPs be required to demonstrate that use of seasonal fuel factors would not result in total cost increases in each month.

ARM noted that for many investor-owned utilities, base rates may already reflect some seasonality. Because utilities' base rate structures vary in this regard, ARM concluded, it may be necessary to determine the customer impacts of incorporating different levels of seasonality into the fuel factors for each utility on a case-by-case basis. ARM stated that as a policy matter it may be unreasonable to use *any* kind of broad index reflecting the actual spread between summer and non-summer spot electricity prices for establishing seasonal differentials in the fuel factors, given the adverse impact on customers that may result.

OPC commented that the current price to beat rate structure includes a capacity cost seasonal differential in base rates. Therefore, OPC determined that in the absence of actual experience in the marketplace, there is no reason to conclude that the existing differential is inadequate. Spectrum expressed concern about the price to beat becoming a below market rate. Spectrum also commented that the 10% materiality threshold in the rule as proposed was too high given that affiliated REPs can only request changes in the fuel factor twice per year.

OPC stated that because the proposed fuel factor differentiation may squeeze headroom in the summer, when household electric bills are highest, they do not recommend any form of seasonal differentiation of the fuel factor. AARP also expressed opposition to the staff-proposed seasonality adjustment. Reliant commented that it does not necessarily advocate a seasonal fuel factor.

Entergy REP, Shell and TNMP disagreed with TXU REP and the Consumer Commenters' arguments that PURA does not permit seasonality. Entergy REP and Shell noted that PURA §39.202(b) does not limit the commission to one fuel factor applicable to all seasons. TNMP opposed the elimination of the seasonal factor as proposed in initial comments by TXU REP and Consumer Commenters. If the commission does not allow seasonal factors, TNMP commented, then the affiliated REP would not be able to raise the price to beat to meet higher costs in the proposed summer season which would eliminate headroom and therefore damage the competitive framework.

Shell urged the commission to include seasonal fuel factors in the rule to help insure that the PTB tracks the true cost of power as closely as possible, sending accurate price signals to customers and to the market as a whole. Shell contended that seasonal fuel factors should be mandatory, not optional as some commenters proposed. Shell reasoned that without accurate price signals customers would not be able to react rationally to changes in the cost of power and that competitors may not be able to serve the residential market.

Entergy REP also supported seasonal fuel factors and believes they should be optional, subject to the constraint that the PTB fuel factors would be designed such that the aggregate annual weather-normalized PTB billings with seasonal factors cannot exceed the aggregate annual PTB billings without seasonal factors for the average PTB customer of each rate class. Entergy REP pointed out several advantages to this approach. First, a PTB customer will pay no more, in the aggregate, than a customer without seasonal factors. Secondly, the affiliated REPs can mirror market prices more closely, enhancing headroom. Finally, the effects of gaming will be mitigated.

Shell, ARM, EPE, Entergy REP, Cities, SPS, AEP, and OPC were generally opposed to using the NYMEX natural gas price index for the establishment of two seasonal factors. ARM, SPS, TNMP, OPC, Shell and Cities expressed concern that gas prices are often significantly higher in the winter than in the summer, while the opposite is true for wholesale power costs. The Cities stated that this runs counter to the commission's apparent attempt to increase the summer price to beat to deflate incentives to game the price to beat. ARM further commented that the NYMEX natural gas index does not track either the price curves or the volatility of electricity prices. Other commenters, including AEP, noted that the seasonal differences in the price of natural gas and electricity have historically been inversely correlated. These commenters reasoned that the NYMEX natural gas price index might not be a reliable indicator of changes in the price of purchased energy.

The City of Dallas asserted that the risk of linking the price to beat solely to the cost of gas is that if the cost of other fuels decreases, then the price to beat would be artificially inflated to reflect the rising cost of gas. Subsequently, once the price to beat period expires, the affiliated REPs could then undercut other competitors and drive them away.

Several solutions were proposed in the event that the commission determines that seasonal fuel factors are necessary and appropriate. ARM stated that a differential of a cent ($ .01) between summer and non-summer fuel factors would be a reasonable starting point for addressing the issue of seasonality. ARM stated that at the opening of the retail market, a one-cent seasonal differential should minimize any potential adverse impact on customers, while giving appropriate signals with respect to electricity price.

Consumer Commenters stated that the staff-proposed seasonal one-cent seasonal differential is not about fuel, but about market prices, gaming, and capacity costs and would add between $10-14 to summer electric bills, which in turn would wipe out the 6.0% decrease under the price to beat. Consumer Commenters also stated that whatever the winter rates would be, a one-cent seasonality adjustment would always be approximately $10-14 more in the summer and as such customers would not see any savings in the summer months. Consumer Commenters did not provide any information to support this assertion.

TNMP also disagreed with the initial comments of OPC and ARM that argued in favor of a fixed seasonal differential, as this does not reflect the costs of each of the affiliated REPs. TNMP contended that these seasonal differentials would arbitrarily produce economic "winners" and "losers" out of the affiliated REPs and the non-affiliated REPs that seek to compete with them.

If the commission does include a seasonal fuel differential for headroom purposes, OPC suggested that the initial fuel factor be developed with an initial summer rate, which is five mills higher in the summer than in the winter. OPC stated that the five mill fuel factor seasonal differential would continue in any subsequent adjustment based upon 12-month average fuel prices. OPC also suggested that if the commission prefers a differential which is developed more precisely, it is possible that an alternative to the five mill value could be developed in each initial fuel factor proceeding based upon the utility's gas generating station weighted average heat rate for summer and winter seasons. OPC stated that ARM's one-cent differential was too high and compared it to their own one-half cent. OPC concluded that a half-cent differential would almost double the existing summer bill differential for some utilities. Therefore, OPC recommended that given the large electric bills experienced by air-conditioning users during hot summers, any seasonal differential should be conservatively selected in order to produce a more modest result.

TXU REP suggested that the commission seriously consider the effect that these proposed rate differentials would have on residential and small business customers. TXU REP's analysis indicated that a five mill per kWh increase in the summer months (OPC's compromise position) would increase a typical residential summer bill by 7.0%, and a one-cent per kWh increase as proposed by ARM would increase typical residential summer bills by 13.5%. TXU REP stated that the increase resulting from Shell's recommended use of the ERCOT-B profile would be 32%. TXU REP argued that the SB 7 model was designed to provide benefits for all customers while avoiding mistakes made in other states.

Seasonal factors applied to all customers, TXU REP concluded, are not consistent with these objectives. TXU REP particularly disagreed with Shell's proposal to establish seasonal fuel factors based on seasonal differences in wholesale power markets relying on the ERCOT-B index for example, to set seasonal fuel factors for markets within ERCOT. TXU REP contended that the proposals of Shell, OPC and others would produce a rate shock that would lead to a consumer outcry comparable to that recently experienced in California.

Cities' suggested amendments would require each utility filing for its seasonal fuel factors to identify all projected firm purchases of power and purchases of economy (non-firm) energy for which the price paid is determined by the price of natural gas or the cost of gas fired generation. Cities suggested this change is necessary to implement a price to beat adjustment mechanism that tracks the impact of changes in natural gas prices on the cost of purchased power as an affiliate should not be permitted to claim and recover hypothetical increases in cost that would not have been recoverable by the integrated utility. Cities also proposed changes to allow for adjustments to the seasonal fuel factors as a result of the gas generation component of current fuel factors. Cities contended that nuclear fuel, coal and lignite prices will not vary with natural gas prices and that SB 7 only allows for the recovery of increases that are the result of increases in natural gas and purchased power expense.

EPE, Reliant, Shell, SPS, and other commenters proposed that an electricity index be used instead of a natural gas index. EPE stated that the use of a power index will capture the effect of a change in gas prices as well as other power market drivers. Shell agreed and requested that seasonal fuel factors be established based on differences in wholesale power market prices. Shell suggested that the prices from the wholesale market could be obtained from *Megawatt Daily*'s Market Report for the regional hubs serving power markets in Texas.

Entergy REP agreed with the initial comments filed by SPS, Shell, and EPE that proposed that seasonal fuel factors be based on purchased energy prices rather than a natural gas index. Entergy REP stated that the fuel-based seasonal price differential as proposed would not be adequate to reflect the overall seasonal price differential that will occur in the wholesale electricity markets. Entergy REP claims that seasonality based solely on fuel costs ignores the seasonality impacts of non-fuel capacity costs that will be reflected in wholesale electricity prices. Entergy REP stated that setting seasonal fuel factors based on the fuel mix and fuel prices in each season will not accurately reflect the seasonal differences in electricity prices. According to Entergy REP, setting seasonal fuel factors in this way would result in seasonal fuel factors that are flat relative to electricity market prices and would likely induce gaming opportunities that the seasonal fuel factors are intended to prevent. Entergy REP supported the proposal by SPS, Shell and EPE to use an electricity index rather than a natural gas index to set the initial seasonal fuel factor. Entergy REP commented that the seasonal shape would most closely mirror the seasonality of the costs faced by competitive REPs thereby providing customers better economic price signals in each season. AEP agreed that a power index would be more beneficial for establishing seasonal fuel factors. AEP acknowledged that there is difficulty in selecting a forward-looking power index that is robust at the start of competition, although it is likely that one will develop over time. When that happens, AEP asserted, the commission should use this index because it will more closely track the expected seasonality of power prices.

Entergy REP proposed a slightly different alternative. Entergy REP stated that the total annual revenue to be recovered through the fuel factor should be based on the projected fuel and purchased power costs for 2002. To set the initial seasonal fuel factors, Entergy REP recommended that projected 2002 annual fuel and purchased power costs be allocated to summer and non-summer seasons based on a known historical relationship between load weighted electricity spot prices for the summer and non-summer periods (such as in the "Into Entergy" market as reported in a publicly available source) and then divided by the applicable summer and non-summer kilowatt-hours in 2002. This method, Entergy REP asserted, would ensure that the seasonal fuel factors more closely mirror the seasonality of the market costs faced by competitive REPs and would provide customers more accurate price signals in each season. In addition, Entergy REP commented that relying on a historical relationship between spot electricity prices that is objective and verifiable is preferable to determining the seasonality of the initial fuel factor based on a projected, unknown fuel mix. Entergy REP proposed changes in the rule to permit the calculation of separate seasonal rolling averages and the adjustment of seasonal factors based on the rate of change between separate seasonal rolling averages and the separate seasonal NYMEX baseline moving averages.

Reliant commented that if fuel factors are the only way to prevent seasonal gaming, then Implied Heat Rates (the price of a purchased energy block for a period divided by the price of natural gas for the same period) rather than natural gas prices, should be used to shape the seasonal fuel factors. Reliant contended that seasonal fuel factors should be used for all price to beat customers and that seasonal fuel factors must be initially shaped and subsequently adjusted using Implied Heat Rates. Reliant proposed that seasonal fuel factors be obtained by calculating one fuel factor, and then shaping the fuel factor for seasonality. Reliant assumed that this process would repeat for each fuel factor adjustment. In other words, under Reliant's proposal, a new single fuel factor would be calculated for each requested adjustment, using the mechanism detailed in the "PTB ADJUSTMENT" section in the Coalition Reply Comments. This formula is discussed in more detail in Question 2 below.

If the commission does not accept Reliant's proposal for seasonality, Reliant recommended that (1) no seasonal adjustment be used, and (2) that price to beat customers (residential and small commercial with demand less than 50 kW) who leave and then return to the affiliated REP be required to choose from one of the following requirements: (a) a seasonal price to beat rate rider equal to the incurred summer subsidy calculated using actual prices from the balancing energy market; or (b) balanced billing, with the affiliated REP having the ability to request a deposit to cover the initial balanced billing subsidy, in addition to the deposit allowed under the customer protection rule. Reliant also suggested that regardless of seasonality, all returning small commercial customers with a peak demand greater than 50 kW should be required to accept a minimum term of one year with a buyout equal to the incurred summer subsidy calculated using actual prices from the balancing energy market.

Cities urged the commission to refrain from instituting a seasonal fuel factor until evidence suggests that residential and small commercial customers are gaming the price to beat.

Upon further consideration, Reliant proposed that seasonality should not apply to residential customers under any circumstances. Restrictions on individual PTB customers should be limited to returning small commercial customers with a peak demand, either in the aggregate or on an individual meter basis, exceeding 50 kW. Reliant proposed that such returning customers be subject to one of two restrictions: (1) seasonal rates, or (2) a tracking mechanism that calculates a running account of the actual cost to serve such customers versus the actual charge to such customers based on allowed summer rates.

TNMP asserted in reply comments that the commission should use three seasons, rather than two, to more accurately reflect the changing energy prices. Entergy REP suggested that the seasonal factors be calculated for the periods of May through September and October through April to reflect the fact that summer load conditions begin in May. ARM agreed with Entergy REP that the summer season should include the month of May.

TNMP stated that the commission should clarify the language of the rule to ensure that the differential in the summer and winter NYMEX natural gas index does not equal the differential in the summer and winter fuel factors. If this change is not made, TNMP asserted it would result in an artificially low price to beat and the concomitant loss of headroom during the summer season, stifling competition and saddling the affiliated REP with a price to beat under which it will suffer losses.

Cities stated that the fuel factor adjustment as proposed is a one-way street in favor of the utilities. Cities suggested that the commission and other parties have the authority to request an adjustment to the PTB fuel factors. In the alternative, Cities suggested that any surcharge should be regarded by the commission as a temporary surcharge. Cities suggested that if gas prices fall 10% below a threshold the surcharge would expire.

Cities expressed concern that the proposed rule permits only the affiliated REP to request an adjustment to the fuel factor and that the one-sided request ensures that the fuel factor will never be lower than its initial level. Cities also objected that the proposed rule does not require any resulting over-recoveries to be flowed back to customers.

The commission finds that under the plain language of PURA §39.202(l), only the affiliated REP can request a change in the fuel factor portion of the price to beat. Furthermore, the commission finds that the combination of the ability to choose service from alternate providers, natural competitive forces, and the operation of the "clawback" under PURA §39.262(e) in the 2004 true-up provide compensation to ratepayers for the price to beat being an above market rate. Finally, one of the benefits of the implementation of retail choice is that there is a more efficient avenue for customers to receive lower prices than through commission rate proceedings.

The commission disagrees with TXU REP, Consumer Commenters, OPC and others that seasonal fuel factors are not contemplated under PURA. PURA §39.202 states that the commission shall determine the fuel factor for each electric utility as of December 31, 2001. PURA Chapter 36 contains the authority for the commission to establish rates. Fuel factors are specifically discussed in §36.203. Section 36.003 provides that rates must be just and reasonable, and rates may not be unreasonably preferential, prejudicial, or discriminatory. There is no specific grant of authority to set seasonal rates, but the commission has for some time set rates that include seasonal variation, including fuel factors, under the broad authority contained in Chapter 36. The commission notes that all investor-owned utilities currently have seasonal base rates, and that the AEP utilities (Central Power & Light Company, Southwestern Electric Power Company and West Texas Utilities Company) currently also have seasonally differentiated fuel factors. The commission concludes that it has the authority under PURA to establish seasonal fuel factors under the PTB.

The commission further disagrees with those commenters, including Consumer Commenters and AARP, who suggested that seasonal fuel factors will increase customer bills and eliminate the 6.0%

PTB decrease and send inappropriate price signals, comparable to those being experienced in the California electric market. First, unlike California, the statute expressly permits a portion of the price to beat (fuel factor) to be adjusted based on significant changes in the costs of natural gas and purchased energy. By contrast, as noted by Entergy REP, in San Diego, monthly electric power exchange prices were automatically passed through directly to customers. Additionally, under a one-cent seasonal differential, customers with average usage would still receive the 6.0% rate decrease contemplated under PURA §39.202(a) on an annual basis. A one-cent seasonal differential would likely eliminate the 6.0% decrease in the summer months (June-September) for customers with average usage. However, such seasonality would not increase a customer's bill over what it would otherwise have been under regulation for the summer months. Moreover, these customers would receive greater decreases in the non-summer months. On an annual basis, price to beat customers with average usage would receive the 6.0% rate decrease contemplated under PURA §39.202(a).

After consideration of the comments received by parties on the issue of seasonality and given the concerns voiced by some parties about the perceptions of the impact on high summer-usage customers and a recognition that residential customers are less likely to exhibit switching behavior that would take advantage of the fact that the PTB may be below market during the summer months, the commission finds that it is reasonable to allow the affiliated REP to request a seasonal fuel factor for small commercial price-to-beat customers (as defined in subsection (c) of the rule) only at this time. The commission does find that nothing in PURA prohibits the commission from setting seasonal fuel factors for all customers, as it currently does for the AEP companies. However, in order to provide continuity for residential customers during the initial transition to a competitive market, the commission declines, at this time as a matter of policy, to introduce seasonality into the residential fuel factor where it does not exist today. For utilities with existing seasonal fuel factors, the commission finds that it is appropriate to allow their affiliated REPs to retain the seasonality that exists in the current fuel factors for all customers, if they so desire.

The commission finds that imparting seasonality to the fuel factor is the only remedy that will be available for the affiliated REP to address gaming concerns. The commission believes that other mechanisms that have been proposed to address the gaming potential such as minimum contract terms if a customer returns to the PTB, seasonal rates only upon return to the PTB, or tracking accounts that effectively pass through market prices to PTB customers (i.e., the TXU seasonal adjustment mechanism (SAM)) should not be adopted because they create significant disincentives for customers to test the competitive market.

Subsection (f)(3)(C) of the rule has been revised accordingly.

*Question 2: Is the use of the NYMEX natural gas price index referenced in subsection (g)(1) the appropriate mechanism to use in adjusting the fuel factor for significant changes in the price of natural gas and purchased energy? If a purchased power index should be used instead of the* *gas price index, what index should the commission use? Are there other adjustment mechanisms that would more accurately reflect significant changes in the price of natural gas and purchased energy?*

This was by far the most controversial aspect of this rule. Virtually all commenters who filed comments and/or participated in the public hearings on this rule expressed an opinion on this issue. The commenters were sharply divided on this question. Some commenters, particularly Consumer Commenters, OPC and Cities, were generally opposed to the use of a purchased power or energy index. A number of other commenters, including most of the utilities and the REPs were strongly in favor of using some type of energy index to adjust the fuel factor portion of the price to beat. Numerous proposals, including gas-only, a combination of gas and purchased energy and purchased energy-only were suggested in comments and at the public hearings. The commission carefully considered all of these proposals before making its decision on this issue.

ARM and Shell commented that the index used in adjusting the fuel factor was not as important as insuring that the initial price to beat fuel factors are set at the proper level. These commenters noted that a competitive market will not develop if the PTB is set at a level below the price that new market entrants must pay to purchase power and ancillary services.

No commenter supported a natural gas price index as the sole mechanism to adjust the price to beat throughout the entire price to beat period. Reliant commented that natural gas by itself is not an adequate means for adjusting the fuel factor. Reliant stated that the old regulatory regime of reconcilable fuel, energy and capacity will be gone on January 1, 2002. After the choice date REPs will buy power, not natural gas or any other generation fuel. Reliant stated that market forces of power supply and demand will affect the price of power and natural gas will be only one component in the market. Reliant and other commenters asserted that natural gas prices have not historically been perfectly correlated with power prices. In fact, Reliant asserted that since power began trading in ERCOT gas price movements explain only 17% of the variance in electric price movements.

TNMP and Entergy REP did not oppose the use of the NYMEX natural gas index if it applied only to the natural gas portion of the utility's current fuel mix. Entergy REP proposed to track changes in the forecasted price of natural gas and apply the changes to the gas portion of the fuel mix rather than applying the changes to the entire fuel factor as proposed in the rule. Under this scenario, Entergy REP proposed to keep the cost components fixed, for example, coal and nuclear, since the prices for those inputs are not as volatile and the costs are generally fixed under the fuel factor rules today. Entergy REP stated that its proposal to adjust the fuel factor would maintain stability in the way that rates are set and adjusted and that it would be relatively straightforward to implement, while also avoiding the problems associated with relying on illiquid electricity forward prices.

TNMP stated that it did not oppose the proposed rule's reliance on the NYMEX gas index because it agrees that the commission should use a transparent index of electricity market prices. TNMP did not believe such an index currently exists. However, TNMP suggested that the commission also consider the impact of the NYMEX on the affiliated REP by applying the NYMEX to a formula that incorporates the affiliated REP's resource mix. Therefore, TNMP concluded, the commission should allow for two types of adjustment mechanisms; one would entail a simple change in the price of the NYMEX and the second would entail a more detailed analysis of the affiliated REP's projected resources similar to the fuel factor proceedings that occur today. TNMP provided sample formulae for these scenarios.

TXU REP stated that the energy purchases the affiliated REP will make beginning in 2002 are unlikely to be fuel-specific and will be based on highly confidential, highly competitive business agreements. According to TXU REP and others, it would be wholly contrary to the intention of SB 7 for the commission to continue to apply traditional fuel factor regulation to an affiliated REP's energy purchases, much less make a prudence determination regarding them.

AEP proposed that a forward looking NYMEX natural gas strip that matches the adjustment period should be used because it would allow the affiliated REP to appropriately hedge and would reflect changes in competitive retail electricity prices vis-à-vis the price to beat. AEP stated that since natural gas is the fuel on the margin in Texas, and since the initial fuel factor already reflects the current fuel mix of each utility, it is more appropriate initially to adjust the fuel factor by the changes in the marginal fuel -- natural gas. AEP reasoned that when a robust forward-looking purchased power index is available, it should be utilized, since it will better track the changes in prices paid by affiliated REPs for supply and the prices that affiliated REPs will use to compete. AEP concluded that adjusting the fuel factor by fuel mix, as some parties have suggested, will not accurately reflect the market conditions for purchasing electricity faced by the affiliated REP and will serve to artificially lower an affiliated REP's fuel factor adjustment.

Other parties contended that an electricity index would be a more appropriate tool for adjustment. TXU REP, ARM, EPE, Entergy REP, SPS and Shell, stated that a purchased power index is a more appropriate way to track changes in the price to beat fuel factor. Shell emphasized that this is an electricity market -- not a natural gas market, therefore changes in the price of purchased power should be the key determinant in adjusting the fuel factor to calculate the price to beat. Shell urged the commission to base changes in the fuel factor on changes in regional power prices as published in *Megawatt Daily*'s Market Report.

EPE stated that relying solely on the use of a gas index to control the fuel factor component fails to adequately take into consideration other key drivers that affect the price of power. EPE also stated that since it is the only Texas utility in the Western Systems Coordinating Council, the use of the NYMEX Palo Verde power price index is the most appropriate indicator of the price of power that is available for delivery to the El Paso region. EPE reasoned that realizing that non-affiliated REPs will have the ability to pass power costs through to their customers, the commission should consider using a single index for affiliated REPs that is comparable so that customers can make an apples-to-apples comparison in choosing a REP. EPE concluded that if a single mechanism is to be used to control the fuel factor component of the price to beat, it should be a power index since that is the commodity that all REPs will trade. SPS stated that an electricity price index should be used to establish the seasonal fuel factors since the REP is not directly exposed to gas prices because it does not own generation.

TXU REP suggested that an electricity index is consistent with the statutory language and superior to a natural gas index for several reasons. The legislature used the terminology "natural gas and purchased energy" with the knowledge that an affiliated REP was prohibited from owning generation and therefore, would not have gas costs that change over time. While a natural gas index captures changing market conditions in the natural gas market, it is not indicative of changes in the electricity market. Conversely, changes in the natural gas market will be subsumed in an electricity index.

Cities maintained that if the PTB is indexed to market prices, the appropriate base for the index is the cost of generation embedded in the PTB. Cities also stated that any changes in the price to beat fuel factor should be temporary, expiring on the first day of the month following a decrease in natural gas prices below the 10% benchmark established in subsection (g)(1)(C). Cities asserted that this adjustment was consistent with its belief that a transitory spike in gas prices should not permanently enrich the affiliated REP.

TNMP argued that the commission should reject proposals to have fuel factor adjustments expire after a certain period of time. TNMP asserted that this proposal is prohibited by PURA which provides for changes to fuel factors only to reflect changes in natural gas and energy prices or where the affiliated REP's financial integrity is threatened.

Reliant concluded that in order to assure adequate headroom, and thus, robust competition, it is critical that the price to beat accurately track the actual price of power, and since the fuel factor is the only mechanism to adjust the price to beat it should be based not only on the price of gas but on the prices of purchased energy as well.

TXU REP stated that the natural gas price index referenced in subsection (g)(1)(A) of the proposed rule would not adequately reflect changes in the cost of electric energy purchased for consumption by customers. TXU REP noted that this is problematic because in all cases affiliated REPs will be purchasing electric energy, but in no case will they be purchasing natural gas for consumption in generating facilities. TXU REP also expressed concern that capacity auctioned and sold will not be available to the affiliated REP from its affiliated PGC. TXU REP asserted that in addition to the purchased power that the affiliated PGC already acquires to meet the customer requirements of the integrated utility today, it will also have to acquire power to replace capacity auctioned and sold. TXU REP contended that the cost of this additional capacity is not reflected in existing purchased power contracts, but will have to be reflected to track the affiliated REP's cost changes during the price to beat period since use of the NYMEX index would not capture these costs. TXU REP stated that a number of factors ranging from generation capacity shortages to transmission constraints and major outages could have a significant impact on the cost of purchased power. TXU REP concluded that the best method to track and adjust for those variations in fuel and purchased power costs is to set and index the fuel factor against a tradable power index. Unfortunately, TXU REP pointed out, a power index equivalent to the NYMEX Henry Hub gas index does not exist within ERCOT at this time, although it is reasonable to assume that an ERCOT futures market will develop during the first five years of the price to beat. Therefore, TXU REP proposed that the rule utilize the NYMEX Henry Hub gas index to adjust the initial fuel factor established under the proposed rule. TXU REP concluded that after a futures market has been developed for ERCOT power and an index is developed that more accurately reflects the affiliated REP's cost of purchasing energy, then future adjustments of the REP's fuel factor should be based on this index.

OPC disagreed with TXU REP on use of an electricity index. OPC stated that even as future indices are developed, it is uncertain whether the transactions will reflect a liquid, fully competitive market. More importantly, OPC stated it is unlikely that such indices will reflect the bulk of bilateral contracts that would comprise the market structure in Texas.

Consumer Commenters also disagreed with proposals to use a purchased power index for adjustments to the price to beat fuel factor. Consumer Commenters stated that a purchased power index, or any index which includes capacity costs should not be substituted for the fuel factor in the price to beat. Consumer Commenters stated that the commission's current rules permit the recovery of purchased "energy" costs through the fuel factor, but prohibit the recovery of purchased "power" capacity or demand charges. Consumer Commenters and Coalition of Cities pointed out that PURA §39.202(l) uses the term "purchased energy", not "purchased power" with regard to fuel adjustments under the price to beat. They also stated that an index will not account for discontinued contracts and other factors that would lower fuel costs. Therefore, they reasoned, it is inappropriate to use any automatic cost adjustment process because it will likely overcharge residential customers. Consumer Commenters also objected to use of an ERCOT wholesale index. Because the ERCOT generation market is designed as a bilateral contract market the price of most power purchases will not be publicly available and thus, Consumer Commenters concluded, the only type of index that could be developed would be based on spot purchases or balancing energy -- both high price products.

The Coalition of Cities stated that the price to beat is intended to guarantee residential and small commercial customers a 6.0% rate reduction and to protect such customers from potential rate increases caused by competition. The Coalition of Cities noted that the Legislature limited adjustments to two scenarios. First, the price to beat can be adjusted to reflect significant changes in the price of natural gas and purchased energy. Secondly, an adjustment can be made to protect the financial integrity of the affiliated REP. The Coalition of Cities contended that the term "purchased energy" is not synonymous with the term "purchased power." According to the Coalition of Cities, the term purchased power is much broader than purchased energy and includes things such as the charges for capacity costs that are not included in purchased energy. The Coalition of Cities concluded that if affiliated REPs are allowed to adjust the price to beat for differences in the price of power, the price to beat would be rendered meaningless. Cities also commented that an index based on firm purchased power cost would not accurately measure the change in the price that price to beat customers would have paid with continued regulation. OPC was also skeptical that an index could be developed for purchased power transactions that will be compatible with adjustments to the fuel factor.

TNMP clarified at the January 22, 2001, workshop that more recent contracts typically do not have capacity components. Since TNMP has no purchased cost recovery factor (PCRF), it recovers its purchased energy costs through its fuel factor.

AEP urged the commission to consider the implementation of a quarterly adjustment mechanism to more accurately reflect PTB fuel and purchased power costs.

Since there is no reliable energy index at this time, several commenters proposed methods to solve this problem. Reliant stated in its initial comments that the new purchased energy product could be determined in a number of ways, although the joint comments with the Coalition detail Reliant's preference. Reliant expressed confidence that public indices will be developed for purchased energy. In the interim and until such indices develop, Reliant committed to working with the Intercontinental Exchange to develop such a product for market opening. Alternatively, Reliant suggested that pricing for a 5 x 16 product could be crafted from the existing capacity auction product by: (1) dividing the premium for the baseload capacity auction product by the on-peak hours in the delivery period and then adding the strike price; and then (2) dividing that result by the average gas price over the delivery period. Finally, Reliant stated that the new purchased energy product could be determined from *Power Markets Weekly* reports 5 x 16 and 5 x 8 (overnight) data, but not weekends. In order to directly use the baseload capacity auction product price (premium divided by capacity factor plus strike), Reliant concluded weekend data could be extrapolated from the weekday data by using a 50% weighting of the 5 x 16 data and a 50% weighting of the 5 x 8 data.

Reliant proposed a solution based on the Implied Heat Rates (price of purchased energy/price of natural gas) that Reliant stated would introduce the concept of purchased energy into the fuel factor adjustment calculations and make them more meaningful and accurate. Reliant proposed the following formula for fuel factor adjustments and the Coalition adopted this formula for the adjustment of the fuel portion of the price to beat:

$$\text{Fuel Factor}_{new} = \text{Fuel Factor}_{base} * (1+((\text{Gas}_{new}-\text{Gas}_{base})/\text{Gas}_{base})) * (1+((\text{Heat Rate}_{new}-\text{Heat Rate}_{base})/\text{Heat Rate}_{base}))$$

Where:

Fuel $Factor_{base}$ = The fuel factor at the time an adjustment is requested. After the fuel factor has been adjusted the first time, it would be the fuel factor currently in use at the time an adjustment is requested.

$Gas_{new}$ = NYMEX futures price calculated under §25.41(g)(1)(A)-(B). The Coalition recommended that the 60-day average contained in the proposed rule be shortened to any one day between the date of the last energy auction and the scheduled date of the next energy auction.

$Gas_{base}$ = NYMEX futures price calculated under as proposed. For the first fuel factor adjustment, it would be the NYMEX futures price calculated under proposed §25.41(f)(3)(D). For all subsequent adjustments, it would be the $Gas_{new}$ from the immediately preceding fuel factor adjustment.

Heat $Rate_{base}$ = the Implied Heat Rate calculated from the last fuel factor adjustment request. The Implied Heat Rate would be calculated by dividing the power prices for any given period by natural gas prices from the same trading day for the same delivery period. For the initial adjustment request, this number would be calculated by dividing the daily Peak ERCOT Index

Power Price data from *Power Markets Weekly* by the daily gas price data from Gas Daily's Houston Ship Channel index, averaged over the entire calendar year 2000. For all subsequent adjustment requests, this number would be the Heat $Rate_{new}$ calculated in the immediately preceding fuel factor adjustment.

Heat $Rate_{new}$ = the Implied Heat Rate from the purchased energy product, which is sold as an annual forward. This value would be calculated by dividing the forward power price from a purchased energy product by the NYMEX futures gas price from the same trading day for the same delivery period covered by that product.

Ideally, the Coalition stated, the Implied Heat Rate should be calculated from a publicly traded product. Until such a product trades in ERCOT the Coalition recommended that auctions should occur on September 1 (covering energy delivered the following January through December), March 15 (covering energy delivered the following June through May) and July 15 (covering energy delivered the following November through October) of each year. According to the Coalition's recommendation, each auction would involve 1.0% of the Texas jurisdictional installed capacity of the affiliated PGC. To ensure compatibility with true market prices, auctions should be conducted under standard terms and conditions. As part of the Coalition's proposal, auction products would be sold pursuant to a standard agreement such as the Edison Electric Institutes' Master Power Purchase & Sale Agreement and credit terms should generally follow the capacity auction rule. The Coalition stated that these auctions would generate individual monthly prices for 5 x 16 firm energy to be delivered in the time period covered by the auction.

At the same time the auction occurs (i.e., September 1, March 15 and July 15), the Coalition stated, the NYMEX gas futures price for gas delivered in each month of the same time period covered by the auction would be calculated. The monthly 5 x 16 firm energy price would then be divided by the monthly gas price to obtain a monthly Implied Heat Rate for each of the 12 months covered in the auction. Finally, these monthly Implied Heat Rates would be averaged to obtain the Heat $Rate_{new}$. Until the Heat $Rate_{new}$ value is calculated based on a publicly traded product instead of an auction, all affiliated REPs requesting a fuel factor adjustment would use the same Heat $Rate_{new}$ in the fuel factor adjustment formula (i.e., all affiliated REPs would conduct the auctions described in this paragraph on the same day, and these auctions would generate one Heat $Rate_{new}$ for all affiliated REPs).

The Coalition recommended that, at the affiliated PGC's option, the auctioned capacity would count toward the 15% total statutory requirement in PURA §39.153. Ideally, the Coalition commented, a commodity product for ERCOT future energy price will develop and once trading volumes reach significant levels, that product should be used in place of the auction prices explained above.

This proposal is not a pass-through of purchase power costs, the Coalition noted. The Coalition pointed out that this is a critical distinction because it means that this proposal would not result in the same market problems that San Diego experienced, because this proposal encourages all REPs to hedge on a forward basis rather than to purchase on a daily spot basis and then pass on the volatile costs or to accrue those costs for future collection. This divergence from the traditional fuel factor model is necessary because the prices of natural gas and purchased energy are not adequately correlated to allow natural gas to serve as a proxy for both the REP Coalition concluded.

Reliant noted that in general there is a pricing continuum with two pricing alternatives (fixed and spot) and two purchase contracting alternatives (fixed and spot). Some alternatives leave the REP more at risk while others leave the customers more at risk. Reliant contended that at one extreme for example there is a fixed retail price and a spot purchase contract price that would result in a situation similar to the one experienced in California by Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) while a spot purchase contract price and a spot retail price would bring about a situation similar to the San Diego situation. Reliant commented that the Coalition Proposal falls somewhere in between, where there is a small margin for exposure to volatile prices by either the REP or the customer.

AEP stated that the Reliant and the Coalition proposals have some merit in that they attempt to make use of forward electricity and natural gas prices by incorporating an Implied Heat Rate mechanism. AEP's primary concern with using power prices to adjust the seasonality of fuel factors is that there is currently not an existing robust forward-looking power index. AEP also proposed that the timing should be adjusted to reflect forward-looking natural gas prices rather than lagging prices in order to prevent a timing problem. AEP also expressed concerns with the heat rate proposed by Reliant and the Coalition. AEP noted the inherent dichotomy between the $Gas_{new}$ portion of the formula (which is a 60-day moving average of NYMEX futures prices) and Heat $Rate_{new}$ (which is an Implied Heat Rate from the purchased energy product sold as an annual forward). Specifically, AEP questioned whether the power price used to incorporate the Heat $Rate_{new}$ would be taken at one point in time and then compared against future forward looking gas prices taken at another point in time. AEP stated that such a mismatch could result in fuel factor adjustments that bear no resemblance to actual changes in market prices of electricity.

OPC claimed that Reliant's fuel adjustment mechanism proposal is apparently intended as a revision to the mechanism Reliant suggested in its business separation plan (BSP) filing. The difference is only semantic, making the adjustment mechanism appear to be a fuel price adjustment. In fact, the proposal for an "implied heat rate adjustment" to the change in NYMEX gas prices, OPC deduced, is a thinly disguised power cost index. By applying changes in the gas-cost-to power-cost ratios to the gas price index, the proposed adjustment is mathematically the same as a power cost index. OPC stated that it is subject to the same criticism discussed in OPC's initial comments.

ARM suggested that the fuel factors should be shaped to reflect the different load factors for the PTB customer classes, since the 5 x 16 energy auction products described in the Coalition's reply comments would not be appropriate for serving all classes. While load factors have not typically been taken into account in establishing fuel factors in Texas, this is common in other states, according to ARM, and nothing in PURA prevents the commission from doing this on a going-forward basis. ARM recommended that such shaping could be preformed by the parties in connection with the technical conferences recommended by Entergy REP in its initial comments.

If the commission declines to adopt the Coalition proposal, ARM suggested that the commission allow the fuel factor to adjust for changes in the price of natural gas, using the NYMEX Henry Hub as an indicator of change, until a reliable, liquid energy index develops. ARM proposed that the following factors could be used to determine whether a market is sufficiently liquid:

1. The index should be published, verifiable, and independent (e.g., an exchange);
2. The index should exhibit significant trading volume;
3. The index should exhibit small bid/asks spread; and
4. The index should have at least a couple of years of published price history.

For instance, a good index would have two to three years of price history, several million megawatts' (MWh) of volume trading every day, daily trading of contracts at least three years out, and prompt-month bid/ask spreads of less than $0.25. ARM suggested that the commission should solicit public comment on whether a proposed index meets these criteria prior to effecting this change. The entire fuel factor should be adjusted by the change in price.

AEP was unclear how Reliant's proposed formula for the adjustment of the fuel factor would affect Central Power and Light (CPL) and Southwestern Electric Power Company (SWEPCO). AEP stated that CPL is only required to auction capacity for one year as a result of their merger agreement and that SWEPCO will be auctioning capacity in a different market.

Reliant, responding to a request for a plan with a phase-in approach presented a compromise proposal (Compromise Proposal) at the January 22 workshop. Although this was not Reliant's preferred approach, Reliant could support it.

The Compromise Proposal would be a phase-in over five years although Reliant stated that different phase-in periods could also be implemented. In 2002 there would be a 100% historical based price to beat. The natural gas price index would be used to adjust the price to beat and the materiality threshold used to make adjustments to the fuel portion of the price to beat would be reduced from 10% to 4.0%. In 2003, 50% of the fuel factor could be adjusted for changes in the natural gas prices according to the Compromise Proposal, and 50% would be adjusted for changes in electricity prices based on the ratio of the premium price in the most recent one-year or aggregated 12 months of baseload capacity auctioned to the premium price in the September 2001 baseload capacity auction. In 2003, the materiality threshold would remain at 4.0%.

In the period between 2004 through 2006, under the Compromise Proposal, 100% of the price to beat adjustment would be based on the electricity price index that would be indicative of the current market prices of baseload power. The fuel factor would be multiplied by the ratio of the current electricity price index to the price of power paid in the September 2001 capacity auction or the most recent baseload capacity auction price or index used to adjust the price to beat. If an appropriate price index develops that is representative of different types of product than the baseload capacity product, 100% of the price to beat adjustment would be based on the ratio of such index to the September 2001 capacity auction price paid for auction products that correspond to the index product.

During 2004-2006 the materiality threshold would be 2.0%. The Compromise Proposal would also reduce the period that closing forward 12-month gas prices are averaged from 60 days to 5 business days and revise subsection (g)(1) as proposed to state that a REP may file a fuel factor adjustment request that is based upon the results of a full requirements request for proposal (RFP) to provide service to at least 10% its expected price to beat load for three years. The adjustment, in \$/MWh would be the difference between the low bid offered by suppliers and the current price to beat minus all non-bypassable charges, losses, ERCOT fees, commission assessments and gross receipt taxes, minus \$5/MWh.

Reliant stated that given the size of its price to beat loads there would be only one entity from which it could purchase sufficient power to serve its price to beat load -- its PGC. Reliant expressed concern over being required to enter into a below market contract with its PGC without some safety guarantee from the commission regarding its treatment of the affiliated PGC in the excess cost over market (ECOM) true up. Therefore, an important aspect of the Compromise Proposal would be that the affiliated REP would enter into three to five year contracts with the affiliated PGC for a declining portion of its price to beat load. The contract prices would equal the regulated cost in the ECOM model for baseload units and ECOM market price for gas units. Reliant noted if the ECOM model provides that a baseload unit is valued at $43 in 2002 but under the buy back contract they have to sell at a lower cost of service price, i.e., $36, the issue is how the $7.00 differential is treated? Again, Reliant sought assurances that it would not be required to bear the risk for not recovering this differential in the ECOM true-up.

AEP agreed with Reliant that if the commission decided that an adequate fuel portfolio must include buyback contracts between the affiliated REP and the affiliated PGC, the affiliated PGC should not be penalized in the PURA §39.262 true-up valuation of ECOM for entering into long-term contracts with its affiliated REP. AEP stated that power contracts between the affiliated REP and the affiliated PGC should be allowed at either (1) market prices, or (2) prices equal to or greater than the PTB less the sum of transmission and distribution charges (T&D), other non-bypassable charges (NBCs), and the ERCOT administrative fee (EF). If the affiliated REP has conducted a Request for Proposals for its power needs and receives no price equal to or less than PTB less (T&D+NBCs+EF), then, by definition, the PTB has been set at less than the market price. If this is the case, AEP contends that the contract between the affiliated REP and the affiliated PGC should be deemed to be equivalent to a market-based contract for purposes of the ECOM valuation in the PURA §39.262 true-up proceeding. Given such a determination, the ECOM of the PGC should not be reduced or otherwise adjusted as a result of such a contract.

Entergy REP agreed that using long-term contracts between a PGC and the affiliated REP in order to hedge the risks associated with its PTB obligations would help to protect the financial integrity of the affiliated REP and provide a more stable transition to competition. However, there are other ways that an affiliate REP can hedge, including buying power and fuel products such as forward strips and options from the market, financial instruments, or auctioning full requirements service through an RFP. Entergy REP commented that each REP should have the flexibility to pursue the hedging strategy that best meets its needs.

AEP responded to the PGC buy-back issue by stating that it was concerned that if the REP is prohibited from contracting with the affiliated PGC whether at market or some other price then the REP could end up in a similar situation similar to California. AEP expressed concern about a situation where output has been sold to a third party. Knowing that the REP has to buy at that location, AEP contended that the price could be driven up as the REP is caught in a short squeeze.

OPC commented that to the extent that the commission believes it is necessary to modify the PTB in order to insulate the financial health of the affiliated REP, approval of such buy back contracts is the lesser of evils. The impact of such buy backs upon the market- based valuation of the generation assets during the true-up could be minimized through strict limitation on the duration of such contracts and in reality may have no adverse impact upon the valuation. The utilities' choice of market valuation methods (i.e., complete divestiture versus sale of minority ownership in the capacity) is likely to have a more significant impact upon the robustness of the market valuations. OPC did not agree with Reliant's view that buy back contracts should alter the reconciliation procedure for the 2002-2005 period specified in PURA. According to OPC, the law contemplates that the affiliated REP will undertake the risk of offering the PTB and does not contemplate that the cost of the utilities' efforts to shield the REP from such risk should be added to the ultimate amount of stranded cost.

Cities stated that if a utility chooses to hedge affiliated REP risks through contracts with the affiliated generating company, the mix of baseload and gas capacity purchased should match the PTB load shape.

Shell opposed a delay or phase-in of PTB rates that reflect the true market cost of power, believing that under Reliant's proposal, non-affiliated REPs will not be able to compete until after 2006. Shell believed that until then the PTB will be below market and competitors will only be able to enter the market by selling at a loss.

At the January 22 workshop, TXU REP proposed its own phase-in compromise position. It proposed this approach for commission consideration to accommodate future fuel factor adjustments, as needed, based on changes in the market price of natural gas until a viable purchased energy index develops.

Among other provisions, the TXU REP phase-in compromise would use an initial 4.0% materiality threshold before fuel factor adjustments could be made, with the threshold being reduced to 2.0% in 2004. TXU REP noted that a threshold requirement is unnecessary because affiliated REPs will be limited to two fuel factor adjustments each year. If the purpose of a threshold is to prevent frequent and confusing rate changes for customers, the two-adjustment limitation will accomplish that objective without leaving the affiliated REP exposed for unrecoverable changes in market prices. Nonetheless, in order to develop a mechanism acceptable to as many interested parties as possible, TXU REP proposed an initial threshold starting at 4.0% and moving to 2.0% in 2004.

In 2003, TXU REP proposed to adjust 50% of the fuel factor based on the ratio of the premium price in the most recent one-year or aggregated 12 months of baseload capacity auctioned to the premium price in the September 2001 baseload capacity auction. For the years 2004 through 2007, the entire adjustment to the fuel factor would be based on one of the following:

1. The ratio of the current electricity price index (indicative of current market prices for baseload power) to the price of power paid in the September 2001 baseload capacity auction (or the most recent baseload capacity auction price or index price used to adjust the fuel factor).
2. If an appropriate price index develops that is representative of a different type of product than a baseload capacity product, the ratio of such an index to the September 2001 capacity auction price paid for auction products corresponding to the index product.
3. If no appropriate index is available, then the same as the electric price ratio in 2003, but using the most recent capacity auction price used to adjust the fuel factor as the denominator.

The commission requested TXU REP to work with other interested parties on the concepts contained in its proposal and to clarify the "fail safe" language that would insure that the price to beat is always an above market rate. In comments subsequent to the January 22 workshop, TXU REP reported that a modified version of the phase-in compromise supported by certain other interested parties had been developed. TXU REP supported the newest version, but also supported the version presented at the January 22 workshop as well as the original Coalition proposal detailed in reply comments filed on January 2, 2001.

AEP supported several aspects of TXU REP's phase-in-proposal. First, AEP agreed that it is appropriate to apply the fuel and purchased energy adjustment to all of the costs of the utility as opposed to some portion of the costs of the utility. AEP stated that linking the adjustment to the current mix does not allow the market to open effectively. AEP also supported the fact that this proposal would utilizes fewer days for the initial gas index, which would provide utilities a better ability to hedge. Finally AEP supported the move from a natural gas index to an electric power index. AEP noted that there was a variation of this proposal that could accommodate SWEPCO.

ARM also supported reducing the period for averaging forward 12-month gas prices to five days rather than the 60-days originally proposed in the rule. AEP stated that the shorter time period would be more conducive to properly managing risk. Also, ARM stated that the materiality threshold should be significantly lower than 10%. Affiliated REPs are already collared by the fact that they may only request two adjustments per year. ARM agreed conceptually with TXU REP's "failsafe" provision although it suggested that the details of the provision need additional refinement. Specifically, ARM expressed concern about the "RFP process", the wholesale product that would be solicited, and whether $5/MWh would provide sufficient headroom.

Entergy REP condoned the use of the capacity auction as a proxy for electric prices during 2003, allowing for the flexibility to use the auction prices in 2004 if an appropriate electric index is not available at that time, and including a "fail-safe" provision. Entergy REP also supported a reduction in the materiality provision from 10% to 4.0% and the shortened trading period for calculating the natural gas index price.

AEP supported the fundamental structure of TXU REP's phase-in compromise. Until a working and reliable purchased power index is operating within ERCOT, AEP stated that it would support use of the natural gas price index for adjustment of the fuel factor. In the event that the fuel indexing mechanism does not properly reflect the market, a fail-safe mechanism should not only adjust the PTB but should also ensure that customers of utilities without stranded costs continue to receive the benefits of the 6.0% PTB rate reduction and ensure that customers of these utilities are not harmed by competition. AEP proposed to adjust the PTB when market prices increase at a rate greater than the natural gas price index or future wholesale energy price index. AEP's concern was that such increases would prevent competition from taking place and prevent the affiliated REP from recovering its wholesale energy costs.

Consumer Commenters did not agree with TXU REP's proposal. Consumer Commenters objected to a pass through of some type of market-based electricity price. They stated that the legislation was passed with the assumption that the price to beat would be above the retail price, that the market price would be much lower. Therefore, Consumer Commenters stated that the legislation does not really give the commission the tools it needs to deal with a different type of market. If there is a problem that needs to be addressed about the market not turning out the way it was expected, then Consumer Commenters suggested such problems be addressed openly and perhaps even through legislation rather than trying to patch something together under the price to beat rule.

OPC commented that it is unreasonable for the commission to state in advance that a price index will be adopted, without any knowledge of the markets or publicly available market indices that may exist in the future. Stating in advance that an index will be adopted, even though considerable debate may arise over the adequacy of the market index, seems to predispose the commission to adopting some type of power cost index even if it is potentially subject to manipulation. OPC argued that the commission should defer the decision on whether it will change the PTB adjustment mechanism until 2004.

OPC stated that it would be willing to support a reasonable "fail-safe" proposal but objected to TXU REP's PTB "headroom" calculation because it doesn't examine the actual financial integrity of the REP, violates PURA §39.202(p), and brings the other parts of the price to beat, such as T&D rates and competition transition charges (CTCs) into the calculation. OPC expressed concern over other problems including the multiple price to beat rates each REP has and the resulting possibility of inter-class subsidies, as well as the failure to link the $5/Mwh target for a REP's margin to actual costs. If a headroom standard is to be used, it should be based on the adequacy of the generation component of the PTB plus the fuel adjustment relative to alternative measures of power costs.

OPC's alternative proposal developed very general standards for an affiliated REP to request a "fail safe" exception with the applicant bearing the burden of proof. The affiliated REP would have to show that its actual incurred power costs were reasonably incurred, reflected prudent diversification and hedging and that, despite the affiliate REP's best efforts, the level of such costs continue to exceed the generation component of the price to beat, as adjusted by the fuel factor.

Cities stated that TXU REP's proposals to phase in market-based indexing are likely to result in the erosion of PTB protection and in excess profits for utilities. Initially, an excess of capacity would hold down prices but the utilities will be protected from fuel cost increases and insulated from the low capacity utilization. Cities stated that the PTB already protects utilities from the risk of low capacity charges, since it includes recovery of costs that might otherwise be stranded as a result of transitory excess capacity. If initial capacity charges are low, stranded cost associated with sales to customers not taking PTB service will be recovered in the true up. Cities added if the true up of ECOM produces stranded cost, PTB customers are subject to possible double recovery.

Cities commented that TXU REP's proposed transitioning of the fuel factor adjustment from gas prices to market prices would maximize the potential for profit. During the first years, the natural gas price index would protect utilities from cost increases while low capacity utilization raises potential stranded costs. Later, the market-price based changes would protect the affiliated REP from higher power prices while the affiliated PGC is reaping the profits from those higher prices, Cities concluded.

Cities' stated that if the Legislature had intended a $5 per MWh floor on headroom, SB 7 could have been written to provide such a floor. Cities recommended that if any headroom floor is approved, it should be designated as both a ceiling and a floor. However, Cities' argued that creation of headroom should not be used to undermine the price reductions that SB 7 and PURA §39.202 provide. Cities noted that to the extent a headroom problem is expected to exist at market opening, the origin of the problem is inflated utility claims regarding T&D revenue requirements, transition costs and stranded costs. The lack of headroom demonstrates that the economics of serving PTB customers make it unlikely that these customers will benefit from competition. It is illogical to remedy this problem by increasing the PTB to a level that exceeds the rate that these customers would have paid with continued regulation in order that they can "benefit" from competition.

Several parties stated that the liquidity of the market index should also be an issue. Reliant offered the following working definition of liquidity: when transactions by a single party do not result in a change in market conditions such as price or bid/ask spread. Unfortunately, liquidity remains a subjective measure, notwithstanding this working definition, because there is no directly observable measure of liquidity. Therefore Reliant suggested that the better question is whether a given index is indicative of true market prices. Reliant argued that indicativeness can be assumed if the product underlying the index is accessible by any interested party, the product underlying the index can be arbitraged by those parties, and the market for the product underlying the index is broad enough to interest both buyers and sellers.

Reliant concluded if these conditions exist, it would be too costly for any participant to manipulate the market index. Both the 5 x 16 purchased energy auction originally proposed by Reliant Energy as well as the capacity auction for the 7 x 24 product meet these requirements for market indicators, according to Reliant. The volume of trades that will be generated through the capacity auctions, the inability of affiliates to participate, and the use of the auction for the ECOM true-up all argue against the possibility of manipulation of an index based on these capacity auctions.

Entergy REP expressed concern about using the NYMEX electricity forward market to index the PTB because of the potential immaturity and illiquid nature of the NYMEX electricity forward market. This concern arises due to the current low, even zero, volume of the NYMEX "Into Energy" index and the large spread between bid and ask prices in over-the-counter trading. Entergy REP stated that there is no single quantitative measure sufficient to determine the existence of a competitive, well-functioning, and liquid electricity market. Rather, according to Entergy REP, there are a number of qualitative characteristics that should be examined including, but not limited to, the following: trading volumes on a NYMEX-type forward market; volume of trading; bid-ask spreads in over-the-counter trading as reported in sources such as *Power Markets Weekly*, and consistency between the capacity auction prices and the forward markets.

Affiliated REPs expressed concern over their ability to hedge properly under certain proposals. TXU REP also stated that it had concerns about its hedging ability when there was a 60-day period over which it would be required to average gas prices. The TXU traders reportedly believe that the rule should move to something more near term to allow the traders and all the various companies the ability to hedge gas prices. TXU REP suggested five days, although it admitted that five days might not be the perfect number.

AEP responded that its central issue was the importance of the ability to hedge. An expert from AEP stated that all of the proposed models of the price to beat do not propose hedging for the price to beat because the company will not have knowledge of what the customer base is. AEP was concerned that they currently manage the system day to day and that there are considerable vagaries that the company has come to live with. For example, the load may be higher due to weather, the loss of units effectively changes the average or marginal costs, and what goes on outside of Texas affects the cost of power in Texas. AEP stated that it currently tries to mitigate these on a daily basis and as long as the costs are shown to be prudent, they have been protected. AEP proposed that the commission provide some type of safety net for the affiliated REP that would allow it to hedge a percentage that would be protected by the commission up to that point.

Reliant pointed out that there is no fundamental value created by longer-term purchases versus spot purchases. Financial theory holds that forward electric prices represent the expected value of future spot price distributions, with each price discounted appropriately for risk. Thus, according to Reliant, hedging cannot create value in isolation. However, since REPs will operate with low margins, some level of hedging is likely in order to prevent excessive earnings volatility. On the other hand, hedging is also costly. Even with forward purchases the REP is likely to lose margin due to the bid/ask spread. Purchasing options to account for the unknown number of customers and their volumes would also be expensive, particularly for summer volumes, according to Reliant. In summary, Reliant contended that it is unlikely that long-term contracting will lead to lower costs to customers. It would, however, limit price volatility to customers and lower earnings volatility for the REP.

Reliant asserted that use of a one-day price would not increase volatility significantly, but would allow commercial hedging to take place. TXU REP stated that the company is putting rules in place to employ short, medium, and long-term contracts to keep costs low.

TNMP pointed out that regardless of the index used to track changes in energy costs, it will not account for changes in energy prices attributable to ERCOT assessed fees. TNMP argued that the rule should incorporate an adjustment mechanism to reflect significant changes in the ERCOT assessed fees including independent system operator (ISO) transaction fees, unaccounted for energy fees, congestion management fees, and others. Consumer Commenters expressed concern about the levels of these fees and concluded that the fees should not be automatically included in the fuel factor, but be subject to review and approval by the commission.

Those parties who argued for power cost indices, OPC commented, ignore the legislative policy for creating the price to beat. OPC explained that the legislative policy for the price to beat is to provide a safe haven for residential and small commercial customers from any adverse impacts of competition that might arise during the transition period. The use of a fuel factor mechanism for adjustments, OPC explained, indicates that PTB customers would not face any consequences greater than under a regulated cost of service rate. OPC reasoned that the Legislature was aware that this provision placed risks on the affiliated REP, which no longer owned generation. OPC contended that the affiliated REP is required to absorb that risk unless it becomes so onerous that an adjustment to the PTB needs to be requested on financial integrity grounds.

The commission first notes that notwithstanding the comments of certain parties in this rulemaking, none of the proposals considered by the commission should result in Texas experiencing the problems experienced in California over the past 12 months. Even if the fuel factor adjustments were tied to a 12 month forward electricity price, the fact remains that it is only the fuel factor portion of the price to beat that can be adjusted, and even that portion can be adjusted no more than twice per year. As a result, the monthly pass-through of average spot market prices (as occurred for San Diego Gas and Electric customers) cannot occur in Texas while there is price to beat protection. Conversely, under no circumstance is the price to beat the "hard" rate cap under which PG&E and Southern California Electric were forced to operate. Even the sole use of a gas price index would allow the price to beat to be adjusted for changing market conditions. Additionally, while the commission hopes the provision is never needed, the ability to raise the price to beat for financial integrity reasons under PURA §39.202(p) also provides protection against a significant divergence in wholesale and retail prices.

The commission concludes that it is appropriate to ensure that headroom under an affiliated REP's price to beat remains no worse than where it initially exists, positive or negative. In other words, to the extent an affiliated REP's price to beat is initially above market, a determination should be made for the headroom that exists on January 1, 2002, and if that headroom were to shrink, the affiliated REP would be able to request a change in the fuel factor sufficient to restore the initial headroom. Alternatively, if the price to beat were initially below market, if market prices of electricity rose such that the price to beat became further below market, the affiliated REP could request an increase in the fuel factor sufficient to return the price to beat to where it started. In both cases, headroom could of course increase if market prices fell, but an affiliated REP could keep headroom from becoming worse. However, to the extent that the price to beat remains significantly below market for a sustained period of time, competition will likely not develop before the expiration of the price to beat period, and it may be likely that an affiliated REP will need to also request a change in the price to beat due to financial integrity issues.

Under this approach, the commission concludes that the market price of electricity to be used for determining the initial/benchmark level of headroom and to permit adjustments should be as follows an average of the prices resulting from a three-year RFP and one year capacity entitlement strips. Under this proposal, affiliated REPs would file the results of a three-year RFP at the end of 2001, near the time of the setting of the initial price to beat fuel factors. Affiliated REPs would then be able to subsequently file RFP results to justify an adjustment to the price to beat to restore the initial amounts of headroom. The capacity auction prices used will be from the initial capacity auctions that will be conducted in September 2001. The commission concludes that it is most appropriate to use the prices for the baseload products that would be needed to serve PTB load. This is similar to the TXU REP proposal and reflects the fact that the capacity auctions will occur frequently during the course of the price to beat period, and that the baseload product will have the largest number of entitlements auctioned. Affiliated REPs will then be able to use the most recent auction of one year-forward strips of auction products, or the most recent aggregated forward 12 months of products to justify a change to the fuel factor.

Use of an average of a three year RFP and the capacity auction prices will allow changes in the PTB due to the average change in wholesale market prices over two different terms. Therefore, to the extent the prices of three-year terms are less volatile than the prices of one-year forwards, use of the average will reflect the commission's belief that it is appropriate for REPs to contract for a variety of different terms of power in order to hedge against market volatility. This approach will require affiliated REPs filing the results of a three-year RFP in late 2001 to calculate the benchmark/initial headroom figure.

The commission concludes that this approach provides the most consistency with the statutory language of PURA §39.202(l), which allows for adjustments to the fuel factor upon a showing that the fuel factor does not reflect significant changes in market prices. The commission shares the concerns raised by a number of commenters that recent increases in the price of natural gas and purchased power may make it difficult for non-affiliated REPs to compete during 2002, even at the levels of shopping credits anticipated by staff. The commission agrees that it is critical that the initial price to beat fuel factor be set as accurately as possible, but disagrees with any assertions that the fuel factor should reflect anything other than the historic fuel mix of the integrated utility, as this is how the fuel factor would have been set under continuing regulation (with allowance for that fuel mix to change as the utility's portfolio changes).

However, the commission also recognizes the undeniable fact that REPs, affiliated or not, will not incur costs after 2002 based on a historic fuel mix; rather, all REPs will be purchasing power in the market. As such, using a measure of the forward market price for electricity at or near the time of the final setting of the initial price to beat fuel factor to establish a benchmark for headroom appropriately reflects the fact that the price to beat may initially be above market in some areas, and below market in others. To the extent that any subsequent changes in market prices cause that headroom to shrink, disappear, or become even more negative, such changes represent significant changes in market conditions that will not be reflected in the setting of the initial fuel factor. Therefore, in accordance with PURA §39.202(l), a change to that fuel factor is warranted. To the extent headroom is initially insufficient to allow non-affiliated REPs to compete for price to beat customers in a particular area, competition will clearly not take hold until the market price of generation falls. However, the commission concludes that maintaining at least the initial level of headroom is fully consistent with the intent of SB 7 that the price to beat serve as a protection for customers while still fostering the growth of a robust competitive retail market.

The rule has been revised to incorporate the changes discussed above. Specifically, two new terms, "headroom" and "representative power price", have been added to the definitions section of the rule. Headroom is defined in the rule as the difference between the average price to beat and the sum of the non-bypassable charges approved by the commission in the pending unbundled cost of service (UCOS) cases. This definition requires a headroom calculation for an average residential and small commercial customer. The term "representative power price" is defined as the simple average of the RFP for 10% of the PTB load for three years and the price resulting from the baseload capacity entitlements in the capacity auctions, using the most recent auction of a 12-month forward strip or the most recent aggregated forward 12-month entitlement. It should be noted that the "representative power price" is not indicative of the true cost to serve a price to beat customer, but instead is simply the blend of power prices that are to be used to gauge how prices are changing in the marketplace.

Subsection (f)(3)(D) has been revised to require affiliated REPs to file information in October 2001 to establish the initial headroom that exists as a result of the initial fuel factor established in October 2001.

Subsection (g)(1)(E) has been revised to permit the affiliated REP to request an adjustment to the fuel factor if the representative power price has changed such that headroom under the PTB has decreased and the adjustment is necessary to restore the amount of headroom established by the commission in the initial fuel factor.

Language has also been added in subsection (g)(1)(C) and (g)(1)(E) to ensure that each subsequent adjustment to the fuel factor is based on the gas prices used at the time of the previous adjustment, if the adjustment is made due to changes in the averaged forward gas price.

The commission further disagrees with Consumer Commenters and others who suggest that the establishment and subsequent adjustment of fuel factors under PURA §39.202 must be applied as it is today and that any change in the fuel factor may only be made in a fuel reconciliation proceeding. PURA §39.202 does not contain any such limitation. Section 39.202 provides that the fuel factor may only be changed twice a year and only in order to reflect significant changes in the price of natural gas and purchased energy. The rule as adopted includes reasonable procedures for adjusting the fuel factor.

The commission also disagrees with the Cities' suggestion to make fuel surcharges temporary. While PURA apparently does not prohibit the commission from imposing this requirement, the commission concludes that such a limitation is unreasonable and unnecessary. The fact that affiliated REPs may only request fuel factor changes twice per year together with the materiality threshold of §25.41(g)(1) should guard against unnecessary fuel factor adjustments. Section 39.202(l) clearly provides for adjustments to the fuel factor based on significant changes in the price of natural gas and purchased energy and affiliated REPs. It is reasonable to allow such adjustments to remain in effect until the next commission approved adjustment. Additionally, this proposal would introduce an added layer of price uncertainty into the market. Finally, the commission concludes that the fuel factor under the price to beat may be adjusted up or down, which should provide a measure of protection for price to beat customers. If affiliated REPs fail to timely request a downward adjustment in the fuel factor, affected customers will presumably seek service from another provider. Additionally, PURA §39.262(e) recognizes the reality that the price to beat may be an above market rate, and requires an offset to the final stranded cost determination to reconcile the amount above market that price to beat customers will pay if they remain with the affiliated REP.

The commission disagrees with Cities and others that the fuel factor adjustment should be only applied to the portion of the historical fuel factor that consists of gas-fired generation or purchased energy. Beyond 2002, the market price of generation will likely be set by gas-fired generation, and as such, it is appropriate to apply the changes in the market price of natural gas and purchased energy to the entire fuel factor in order to maintain the level of headroom in the price to beat.

Furthermore, the commission finds that it is appropriate, after a sufficiently liquid electricity commodity index has developed in an affiliated REP's power region, and the power generation company affiliated with the affiliated REP has finalized their stranded cost determination and non-bypassable charges or credits, as appropriate, to allow affiliated REPs to request a change to its fuel factor in order to reflect changes in the price of purchased energy indicated by this index. The commission finds that it is not appropriate to move to such an index until the stranded costs of the affiliated PGC are finalized as any stranded cost charges (or credits to return prior stranded cost collection) will not be finalized until stranded costs are finalized. At that time, if the price to beat for an affiliated REP is in danger of being below market because of high market prices for generation, the return of any excess mitigation, or negative stranded costs if the commission determines that it has the authority to require the return of negative stranded costs, can be used to address concerns about headroom, and thereby mitigate the effects of high market prices on price to beat customers. Subsection (g)(1)(F) has been added to allow for this transition and prescribes these preconditions and the method by which an affiliated REP must transition to the use of an electricity index.

*Question 3: In the provisions of paragraph (g)(1), is 10% the appropriate threshold for an adjustment to the fuel factors? If an index other than NYMEX natural gas prices is ultimately chosen by the commission, what threshold would be appropriate for that index?*

Entergy REP stated that in general, a 10% threshold that uses NYMEX gas prices is appropriate. Entergy REP recommended that the adjustment threshold be based on the rate of change of the NYMEX gas contract versus a baseline NYMEX gas contract price and that the gas portion of the baseline price to beat should be adjusted in cases where the threshold is reached and a requested change in the fuel factor is made. However, Entergy REP concluded that due to potential exposure to the affiliated REP at price to beat levels that are less than the 10% threshold, the affiliated REP should also have an opportunity to demonstrate to the commission that a change in the market price of purchased power/gas is significant even if the 10% threshold has not been met. In reply comments Entergy REP altered its position in favor of a 4.0% threshold.

Several affiliated REPs expressed concern that the 10% factor was too high or that a set factor was unnecessary. Reliant, TXU REP, and AEP concluded that a fuel factor adjustment threshold is unnecessary. TXU REP stated that the 10% threshold is too high, particularly since affiliated REPs are limited to only two opportunities per year to seek fuel adjustments. TXU REP stated that under current commission rules utilities are allowed to revise their fuel factors twice a year and are required to petition the commission to refund or surcharge if they have materially over or under-collected fuel expenses, with the materiality threshold being defined as 4.0% of annual estimated fuel costs. TXU REP pointed out that the significant difference between the proposed rule and existing fuel factor provisions is that the current process allows a utility to request a refund or surcharge if its fixed fuel factor has materially over or under-collected its fuel expenses. Since the proposed rule contains no surcharge mechanism, if fuel prices increase, an affiliated REP bears all the costs associated with the difference between its fixed fuel factor and the cost of the power it buys, because a fuel factor adjustment only provides a remedy going forward. Therefore TXU REP recommended that the proposed rule be amended to permit an affiliated REP to request no more than two fuel factor changes each year without any minimum materiality threshold. TXU REP argued that the commission should consider the rate shock that customers would experience if rates were held steady until a 10% or greater change in fuel prices occurred, at which time the entire increase would be added to the customers' bills. Reliant stated that the 10% threshold is far too large, especially when contrasted with the 4.0% threshold under the current fuel rule.

TNMP urged the commission to adopt a materiality threshold of 4.0%, stating that a materiality threshold of 10% is unnecessarily high and that the result of imposing this high materiality threshold would be to force affiliated REPs to maintain prices that are not warranted by the market cost of energy.

TNMP also expressed concern that the procedural schedule under this process could take as long as 135 days, which could result in additional disparities. SPS suggested that the appropriate threshold level to use in adjusting the fuel factors will be dependent on the level of headroom available in the final price to beat rates. However, the level of headroom won't be known until the unbundled delivery rates and final price to beat rates are established. SPS reasoned that if headroom is significantly squeezed, then the proposed 10% threshold is too high and a lower threshold may be more appropriate.

TNMP and Entergy REP both argued that 4.0% would be a more appropriate threshold. TNMP stated that some commenters incorrectly assumed that the affiliated REP would never seek to lower the price to beat. TNMP asserted that if market prices decrease significantly, the affiliated REP will either lower its prices or expose itself to competitive disadvantage.

The Coalition proposed a "safe harbor" where any affiliated REP meeting the criterion (lesser of 4.0% of the index or $40 million in lost headroom over an annualized period) should be automatically allowed an adjustment as calculated under Reliant's proposed adjustment.

OPC stated that reliance upon the 4.0% threshold is misplaced for two reasons. First, OPC argued that the 4.0% threshold in the existing fuel rule exists in a reconcilable fuel cost regime where over-recoveries will be returned to ratepayers. Secondly, OPC reasoned the denominator of the 4.0% threshold in the current fuel rule is based upon the total fuel balance including nuclear and coal.

Consumer Commenters and OPC both contended that if the commission adopts a materiality threshold it should be greater than 10%. Consumer Commenters stated that the rule should not specify a materiality threshold and should not allow an affiliated REP to change the fuel cost factor based on an index. All fuel costs must be reviewed Consumer Commenters stated, to assure that higher costs in one category are not offset by declining costs in another category. Consumer Commenters added that the rule should specifically state that the commission or other parties have the right to request to have the fuel factor lowered to reflect market prices. Consumer Commenters concluded that the materiality threshold for defining "significant" should be higher than 10%, and that "significant" changes should be substantial and long term, especially since they are not subject to reconciliation under the proposed rule. OPC did not believe that 10% would be an appropriate threshold if it is assumed that neither the commission nor any other interested party may request a downward adjustment. OPC concluded that in the absence of additional information about which index is chosen, a threshold of 15-20% would be more reasonable without regard to whether the index is based on gas or purchased power.

AEP suggested that in lieu of a threshold factor, the use of some combination of a more continual adjustment (i.e., quarterly) of the price to beat with market prices coupled with deferred accounting treatment of the losses or gains associated with the affiliated REP's changing supply costs.

ARM expressed concerned about whether non-affiliated REPs will have sufficient notice prior to a change in fuel factor. To the extent that non-affiliated REPs offer products that are a percentage discount off of the PTB, those REPs will need sufficient advance notice to make the corresponding change in their rates. ARM suggested two options for ensuring sufficient notice would be to establish a predetermined schedule for affiliated REPs to file for fuel factor changes, such as designated time periods in the spring and fall, as is being done to set the initial fuel factor. Another option would be to require a 30-day notice period prior to any change in fuel factor.

Based on the comments received, the commission concludes that a 4.0% materiality threshold is reasonable. The commission disagrees with those commenters suggesting that there be no materiality threshold. PURA §39.202(l) specifies that PTB fuel factors may be adjusted for "*significant* changes in the market price of natural gas and purchased energy...." (emphasis added). Use of the term "significant" indicates that some sort of threshold be demonstrated in order to justify an adjustment under §39.202(l). On the other end of the spectrum, the commission disagrees with OPC and Consumer Commenters who suggested a threshold in excess of 10%. While some materiality threshold is appropriate, it should not be excessive. If the threshold is set too high, affiliated REPs will be unable to meet it without first incurring significant losses. The commission believes such a result is contrary to the intent of PURA §39.202.

The commission concludes that a 4.0% materiality threshold is reasonable because such a threshold is analagous to the existing materiality threshold in the current fuel rule. While the commission recognizes that the current 4.0% threshold is based on the current solid fuel and gas mix of the integrated utility, in a competitive market, the market clearing price of purchased power will be set by the marginal unit in the market, which will most likely be a combined-cycle gas turbine.

*Question 4: In light of the seasonal fuel factors proposed by subsection (f)(3), is the minimum contract term established in proposed PUC Substantive Rule §25.477 (a)(8) (published in the September 1, 2000, Texas Register at 25 TexReg 8554) an appropriate or necessary mechanism to discourage customers from gaming the affiliate REP's price to beat rates?*

Although commenters acknowledged that the commission has rejected minimum term requirements in the customer protection rulemaking (see 26 TexReg 125 (January 5, 2001)), many addressed this issue again in this rule to support the use of minimum term requirements. Entergy REP offered comments about the importance of permitting affiliate REPs to require returning customers to agree to minimum term contracts. Entergy REP stated that anti-gaming provisions are necessary to ensure a robust, competitive market and to protect the price to beat supplier from undue risk. Entergy REP commented that the proposed rule's treatment of the fuel factor may not adequately allow the seasonal market value of wholesale electric energy to be reflected in the price to beat. Entergy REP commented that utility fuel factors are cost-based and do not necessarily track competitive market electricity prices. To mitigate risk to the price to beat provider, Entergy REP maintained that minimum contract terms of 12 months or other anti-gaming provisions are appropriate for price to beat customers who seek to return to price to beat service after receiving service from a competitive REP.

EPE stated that affiliated REPs are prohibited from including a term of service in agreements with residential and small commercial customers whereas non-affiliated REPs do not have this same prohibition. EPE recommended that all REPs be placed on equal footing in this regard and be given the discretion to use minimum contract terms in a non-discriminatory manner. SPS, TNMP and AEP also supported the use of minimum contract terms. SPS stated that a minimum contract term for price to beat customers returning to the affiliated REP was necessary because requiring the customer to remain for a minimum term helps the REP ensure that any monthly imbalances between volatile costs and non-volatile revenues will balance out over the year. AEP strongly supported a one-year minimum contract term regardless of the length/nature of past customer relationships.

AEP and Reliant argued that the prohibition on minimum contract terms for small commercial customers violates the cost allocation principles underlying commercial rates that have minimum terms. AEP supported the revision of this prohibition to take into account commercial rates that currently have minimum terms. TXU REP commented that large commercial customers should be required to fulfill any contractual service obligations they have to their existing retail electric provider before being able to return to the price to beat rates. Entergy REP concurred with TXU REP on this point.

Reliant proposed mechanisms to discourage customers from gaming the system. These proposals are addressed above in Question 1. Consumer Commenters opposed Reliant's plan that required a customer returning to the price to beat to choose either a seasonal rate rider or balanced billing with an additional deposit. Consumer Commenters suggested the proposal be rejected as it is inconsistent with SB 7 and punishes the consumer for exercising a right that is provided by law.

TXU REP stated that the commission in more than one rulemaking proceeding has acknowledged a need to develop mechanisms to prevent the kind of gaming that has occurred in other states where the retail markets have already opened to competition. TXU REP concluded that seasonal fuel factors should not be applied to all customers to prevent gaming because of the harsh rate impact they will have on customers, particularly residential customers, during the summer months. TXU REP also perceived that significant gaming by residential and small business customers appears less likely, in large part because of mechanisms employed in rules like those governing aggregation, provider of last resort (POLR) and customer protection.

TXU REP proposed a solution that focuses on commercial customers with peak demands greater than 50 kW but less than 1000 kW. TXU REP reported that its discussions with Pennsylvania market experts indicated this customer group has contributed to the gaming problems in Pennsylvania. TXU REP determined that these customers have the greatest ability to game the affiliated REP's price to beat, as they are able to assess available pricing options and to unfairly manipulate the system to choose the most favorable combination of market-based and semi-regulated rates. In lieu of the seasonal fuel factor mechanism, TXU REP proposed to give commercial customers over 50 kW two choices when they return to the affiliated REP: (1) accept service at the price to beat with a one-year term or (2) accept a price to beat rate under a seasonal adjustment mechanism (SAM) rider. Under TXU REP's proposal the SAM rider would be a market price curve, reflecting on a monthly basis, the difference between the price to beat and the affiliated REP's cost to purchase electricity. TXU REP contended that a provision should also be added to the rule to prohibit REPs, aggregators, and agents from gaming the price to beat by providing incentives or inducements for customers to switch to the affiliated REP and to provide penalties for violations.

AEP and Entergy REP commented that seasonal fuel factors alone are inadequate to prevent gaming. Entergy REP stated that TXU REP's claim that seasonal fuel factors are unnecessary for small commercial customers is unsupported. TXU REP fails to mention, Entergy REP reported, that the Pennsylvania Commission had to intervene when a competitive supplier publicly threatened to dump 48,000 residential customers back to price capped service due to high summer prices. The resulting rule in Pennsylvania required a returning residential customer to stay for a year at a fixed rate or choose a monthly market price rate. Entergy REP concluded that the actions in Pennsylvania suggest that anti-gaming concerns are valid as applied to small commercial customers and their suppliers, and emphasize the need for seasonal fuel factors to address these concerns.

AEP noted the problems in Pennsylvania and other states where gaming has occurred. AEP stated that while it believes that gaming provisions should be directed at larger, more sophisticated commercial customers, it believes that small commercial customers are equally capable of "gaming" with more serious consequences, as the profit margins are smaller. AEP stated its support for the adoption of each of the following methods as a legitimate means to prevent gaming: (1) requiring customers returning to the price to beat to remain for one year; (2) prohibiting competitive REPs from making offers that directly or indirectly seek to game short-term discrepancies; (3) seasonal price to beat rate riders for returning customers; and (4) the opportunity for an affiliated REP to require a deposit to cover a balanced billing subsidy.

Shell stated that TXU REP's initial comments on gaming missed the point, which is that accurate pricing of default service is necessary whether or not gaming occurs. Shell argued that if the price to beat is set artificially below the real cost of power, competitors would never be able to offer lower rates to induce customers to switch suppliers. While that result may serve TXU REP's interest in maintaining its role as a monopoly provider, Shell commented, it does not serve the legislative policy and purpose of SB 7.

Reliant pointed out that its proposal is slightly different from TXU REP's. Reliant stated that small commercial customers with a peak demand of less than or equal to 50 kW and all returning residential customers should be subject to no requirements other than those in the proposed rule. However, there should be a way to remove the incentive for aggregators and REPs to offer incentives or inducements for customers to switch. Reliant and the Coalition recommended that there be incentives to prohibit the REP and aggregator from serving as switching agents for the customers whereby they could effectuate a switch without further notice to the customer. The penalties, Reliant suggested should include a mandatory repayment to the affiliated REP of all additional costs as a result of improper gaming plus administrative penalties and the discretionary revocation of REP and aggregator certificates. Further

Reliant proposed that affiliated REPs have the right to investigate when they believe gaming by an aggregator or REP is occurring or has occurred.

TXU REP stated that residential and small commercial customers are unlikely to engage in gaming of the price to beat rates and that the imposition of seasonally adjusted prices on these customers is a solution for a problem that does not exist. The Cities and Consumer Commenters agreed. Consumer Commenters reiterated that residential customers practically cannot and do not game the system, and gaming in other states has been done by large customers and REPs who dump their customers.

TXU REP also proposed and supported another mechanism to minimize the risk of system gaming without preventing customers who wish to return to the status quo from doing so. TXU REP's alternative proposal stated that all non-residential customers with a peak demand greater than 50 kW that return to the affiliated REP on or after April 1 of any given year must agree to pay the net cost of service for the period of May through October of that year. The affiliated REP would track the amount of energy delivered to these customers, the price these customers actually pay the affiliated REP and the affiliated REP's cost to purchase energy for these customers (price in the balancing market). TXU REP stated that this information would be used to calculate a running account balance with these customers, if one of these customers switches away from the affiliated REP before the account balance becomes zero, then the customer must reimburse the affiliated REP for the account balance at the time of the switch. TXU REP argued that this proposal should eliminate the incentive for large customers to game the system and would allow other REPs to compete for these customers by paying the customer's exit fee themselves.

Consumer Commenters agreed with TXU REP that the actual "gamers" should be punished. While the Consumer Commenters agreed with TXU REP's proposal they clarified that they wanted to ensure that small customers who might succumb to inducement by REPs or aggregators should not be punished.

TNMP stated that absent a protective mechanism, a competing REP could undercut the affiliated REP's higher summer seasonal price to beat and drain off the affiliated REP's customers during the more lucrative summer season. TNMP further noted that by simply holding its price constant, the competing REP could shed those same customers back to the affiliated REP during the less lucrative winter period, when the price to beat drops below the competing REP's price, as dictated by the seasonal adjustment. TNMP proposed two mechanisms to address the potential for gaming. First, TNMP stated that the proposed rule should allow the affiliated REP to respond to the appearance of gaming by quickly changing the seasonal differentiation in the factors without changing the overall revenues received under the factors. TNMP argued that the affiliated REP should necessarily be able to implement this type of adjustment to the differential more quickly than the regular adjustments to the overall factors in order to impact the gaming in the season it occurs. Secondly, TNMP argued that the commission could lessen the problem in the first instance by using three seasonal factors instead of two. TNMP suggested the following three seasonal factors: December-March, April-July and August-

November. TNMP concluded that these three factors should provide a smaller differential change in each factor because the summer peak months are divided and combined with more moderate usage months which provides customers with less incentive to game the system.

Cities, Shell, ARM, OPC, and Consumer Commenters opposed use of a minimum contract term. Shell stated that forcing customers to accept a minimum term for statutory default service would discourage participation in the competitive market and would be inconsistent with the customer choice initiatives in PURA. Shell supported adjusting the fuel factor so that the price to beat would reflect significant changes in the cost of power. ARM echoed Shell by stating that allowing the affiliated REPs to tie up customers under annual contracts would significantly undermine competition. ARM stated that under the utilities' proposal of forcing returning price to beat customers to a one year term, not only would the affiliated REPs have all the customers who have not chosen another supplier at market opening, they would also be able to make returning price to beat customers unavailable to competing REPs for a year. ARM stated that a more preferable market based solution would be to incorporate seasonality in the price to beat.

Cities, Consumer Commenters and OPC commented that they do not foresee a propensity for residential and small commercial customers to game the system. Cities stated that unless and until the commission determines a prevalence of residential customers gaming the PTB for financial advantage during high cost months, that any term limits the commission may devise should only apply to industrial and commercial customers. OPC stated that the summer/winter gaming problem is more likely to arise in the context of non-PTB large commercial/industrial customers who have sophisticated metering and energy management strategies. Consumer Commenters added that if returning to the price to beat because a customer is dissatisfied with higher prices or poor service is "gaming" then that is exactly what the Legislature intended. OPC argued that the five-year offering of the price to beat by the affiliated REP was intended to provide a long term safety net for small customers. ARM agreed with the these commenters that it would be anti-competitive to require returning price to beat customers to accept a minimum term contract as no other deregulated industry such as banking or telecom has these requirements. Limiting customer's right to choose in this manner is contrary to the purpose of SB 7, ARM argued.

The commission disagrees with those commenters suggesting various penalties (i.e., minimum contract terms, seasonal rates applied only to returning to customers, and other monetary penalties) to be applied to returning price to beat customers as a means of preventing gaming. As discussed previously in response to preamble Question 1 above, the commission is concerned that imposition of such restrictions would discourage customers from ever leaving their incumbent providers and thereby thwart development of a competitive market. The commission seeks to discourage gaming of the price to beat by either customers or REPs. One way to address gaming is through the use of seasonal fuel factors. For reasons discussed previously in response to Question 1 above, the commission has concluded that use of seasonal fuel factors for small commercial customers should be the only remedy for affiliated

REPs who are concerned about gaming. The commission agrees with those commenters suggesting that REPs and aggregators be prohibited from serving as switching agents for the customers whereby they could effectuate a switch without further notice to the customer.

However, the commission notes that Substantive Rule §25.482 of this title (relating to Termination of Contract) provides that customers who have their contract terminated by their REP, or are abandoned by their REP, are required to be notified that they can select an alternate REP or be switched to the POLR. Furthermore, Substantive Rule §25.474 of this title (relating to Selection or Change of Retail Electric Provider) outlines the procedures for a REP to switch a customer to their service and addresses penalties for unauthorized switches. As such, the commission does not believe that the opportunity exists for REPs to serve as a switching agent for customers or to transfer a large number of customers to the affiliated REP without the affiliated REP's consent, unless the affiliated REP is serving as the POLR at the price to beat.

The commission has revised subsection (j) of the rule to place explicit prohibitions on non-affiliated REPs from providing incentives to encourage customers to return to the PTB. The commission also agrees with Reliant that affiliated REPs already possess the right to investigate gaming by aggregators and REPs and, if necessary, to file a complaint before the commission to address such problems. This should also reduce the potential for gaming.

*Question 5: Should the commission further define what showing should be required by an affiliated REP under subsection (g)(2) to demonstrate that the affiliated REP will not be able to maintain its financial integrity under the price to beat? If so, what standard should be used in this determination?*

AEP, SPS, Reliant, TXU REP, and Entergy REP commented that it is unnecessary for the commission to define what showing should be required by an affiliated REP under subsection (g)(2) to demonstrate that the affiliated REP will not be able to maintain its financial integrity under the price to beat. TXU REP and ARM commented that the definition of financial integrity has been well established by prior commission orders and appellate court decisions and that the commission can rely on these standards with respect to the issue of an affiliated REP's financial integrity in relation to its ability to provide service pursuant to the price to beat. TXU REP reasoned that it is very difficult to predict now what the market will look like in the next few years, much less what standards should be used to judge whether an affiliated REP's financial integrity is jeopardized under any particular market conditions. This is an assessment that will need to be made on a case-by-case basis, TXU REP reported, relying on information that may potentially be competitively sensitive.

Entergy REP and TNMP commented that the financial integrity standard should be a low one. TNMP urged that the standard for an adjustment to protect the affiliated REP's financial integrity be set relatively low because PURA severely limits the commission's ability to adjust the price to beat. If the threshold for the adjustment is set too high, TNMP asserted that an affiliated REP will be pushed to the brink of financial ruin before it can obtain an adjustment and would then operate prospectively on that brink. TNMP argued that no commenters offered a legal basis to require affiliated REPs disclose sensitive information. More importantly, TNMP stated that the imposition of a strict and exacting standard, while superficially pro-consumer, actually threatens long-term consumer harm, because while the affiliated REP is losing money the consumer is insulated from the market conditions.

Entergy REP stated that if the price to beat provider's financial integrity is impaired because the price to beat is set too low, then barriers to entry will be erected for prospective market entrants. Entergy REP commented that the financial integrity test should balance the affiliated REP's interest and the interest of fostering competition. AEP stated that affiliated REPs should have the flexibility to demonstrate to the commission why their particular facts and circumstances will result in their affiliate REP's inability to maintain their financial integrity under the price to beat.

OPC and Consumer Commenters commented that the standards should be strict. OPC stated that it is not necessary at this point to outline in detail the procedures that should govern such a process. However, OPC stated that regardless of when such a procedural rule is enacted, the standards and procedures for granting such requests should be very strict. OPC stated that a financial integrity criterion is meaningless unless the commission simultaneously reviews the reasonableness and efficiency of the affiliated REP's costs. OPC reasoned that because almost all of the affiliated REP's costs are likely to be payments to other affiliated entities, the affiliated transaction standards should be applied in these proceedings. For that reason, the proceedings will be extensive and time consuming and should not be undertaken except in instances of deep financial distress.

OPC suggested (and Consumer Commenters agreed) several criteria for proceedings under proposed subsection (g)(2). The first suggestion is that the relevant financial integrity test should hinge on the existence of negative cash flow, taking into account reasonable and necessary expenses. The second criteria is that the affiliated T&D utility should be required to justify its costs whenever the affiliated REP makes an application under this section. This would allow the commission to correct excessive delivery charges if that is the cause of the REP's financial distress, OPC suggested. Finally, OPC suggested that to the extent that the affiliated REP's access to capital is through the holding company, the overall impact of the REP's financial distress upon the holding company should be examined.

Consumer Commenters feared an affiliated REP may attempt to limit the financial information available to the commission and parties' to review based on claims that it is "competitively sensitive." Consumer Commenters stated that in California the utilities' claims of financial hardship fly in the face of the substantial profits earned by the utilities' generation affiliates during the same high market period.

Reliant reiterated that it is unnecessary at this time for the commission to set up objective standards for a showing of financial hardship. Reliant disagreed with the suggestion of OPC and others that the impact of the affiliated REPs financial distress on the holding company should be looked at when determining whether the REP is experiencing financial distress. Reliant stated that this should not be used when and if standards are adopted. Reliant claimed there is no basis in either past regulation or general logic for this assertion. Integrated utilities are independent entities; other entities are not required to subsidize the utilities and the entire holding company is not required to be in financial distress before the utility can receive a rate increase.

The commission concludes that the standard for an adjustment based on financial integrity should be high. The commission agrees with TXU REP, ARM and others that the definition of financial integrity has been established by prior commission orders and appellate case law and therefore does not believe further definition of this standard is necessary at this time.

*Question 6: Can the registration agent provide verification for small commercial customers similar to that described for residential customers in subsection (l)(4)(C)(i)?*

ERCOT stated that if ERCOT is designated as the registration agent, it would be able to provide the commission with verification reports regarding residential and small commercial customer migration to non-affiliated REPs. AEP and OPC supported ERCOT as the registration agent. TNMP stated that the registration agent should be able to provide the information for small commercial customers.

Entergy REP and SPS noted that ERCOT will not have the necessary load/use data for non-ERCOT customers.

Reliant questioned whether ERCOT, as the registration agent, could differentiate small commercial customers with peak demand below 20 kW. SPS stated that the registration agent may be able to provide verification for small commercial customers under 20 kW, but would not have the consumption data needed to verify small commercial customers over 20 kW. ERCOT stated that it could differentiate such small commercial customers.

Based on the comments received, the commission agrees with ERCOT and concludes that no change to the rule to address this question is necessary.

**§25.41(b)**

Consumer Commenters commented that the provisions of subsection (b) should be revised to reflect that the PTB is also intended to provide an immediate rate decrease for small consumers and to assure consumers there will be a price capped service option available for the first five years of the retail market. Consumer Commenters contend that as proposed, subsection (b) only focuses on competitors, and does not adequately reflect the protection aspect of the price to beat.

The price to beat serves a dual purpose -- to provide a rate decrease for residential and small commercial customers and to assure that these customers will have a price capped service option available for the first five years of the retail market. The commission believes that the rule as adopted properly reflects both aspects of the price to beat.

**§25.41(c)**

EPE commented that the provisions of proposed subsection (c)(4) should be modified to reflect the fact that EPE measures demand on a 30-minute interval. As proposed, subsection (c)(4) measures demand only on a 15-minute interval.

The commission agrees and has amended the rule to permit demand measurement on either 15 or 30-minute intervals.

EPE commented that proposed subsection (c)(5) excludes a part of the corresponding PURA provision governing price to beat. Specifically, EPE refers to PURA §39.202(n) which provides that "in a power region outside of ERCOT, *if customer choice is introduced before the requirements of Section 39.152(a) are met*, an affiliated retail electric provider shall continue to offer the price to beat to residential and small commercial customers, unless the price is changed by the commission in accordance with this chapter, until the later of 60 months after the date customer choice is introduced or the requirements of Section 39.152(a) are met." (emphasis added). As proposed, the definition of the price to beat period excludes this phrase.

The commission agrees with EPE on this point and has amended the definition of "price to beat period" accordingly.

SPS and Entergy REP both commented on the definition of small commercial customer in proposed subsection (c)(9). Both of these companies commented that the definition of small customer in the rule should be defined as "a commercial customer having a peak demand of 1,000 kilowatts or less." As proposed, the definition uses the term "non-residential retail customer".

The commission disagrees with SPS and Entergy REP. In the absence of a clear method to distinguish whether a customer is "commercial" or "industrial", the commission concludes that the intent of PURA §39.202(o) was to provide the price to beat to any customer with a peak demand of 1,000 kW or less, regardless of how that customer may otherwise be classified under a particular utility's tariff.

Cities expressed concern about non-roadway lighting and asked that the price to beat apply to non-roadway lighting. City of Dallas also expressed concerns about non-roadway outdoor security lighting and the fact that while street lighting will remain regulated, the utilities have been contacting their customers and taking a very narrow view of what regulated lighting is. City of Dallas proposed either to keep non-roadway lighting on a regulated rate or the price to beat and expand the definition of street lighting.

The commission concludes that any non-metered point of delivery with peak demand less than 1,000 kW should be considered a small commercial customer and therefore eligible for the price to beat. The commission has revised the definition of small commercial customer to incorporate this change and believes that this change addresses the Cities' concerns about lighting customers.

**§25.41(d)**

ARM stated that this section should be clarified to state that the 6.0% decrease does not apply to fuel and purchased power, but that the discount applies only after the entire cost of fuel and purchased power is backed out of bundled rates. TNMP expressed similar concerns. OPC argued that a calculation of the 6.0% rate reduction only upon the base rate portion of customer bills is not supported by any reasonable interpretation of SB 7. OPC quoted PURA §39.202(a), stating that its use of the word "rates" refers to any "compensation, tariff, charge, fare, toll, rental, or classification that is directly or indirectly demanded, observed, charged, or collected by a public utility" as defined in PURA §11.003. OPC argued that the rates in effect on January 1, 1999, must include fuel charges. OPC stated that the calculation change proposed by ARM would reduce the ratepayer benefits of SB 7.

The commission disagrees with ARM and agrees with OPC. PURA §39.202(a) provides for the 6.0% discount to be applied to the average bundled rate in effect on January 1, 1999, which included a fuel factor. As specified in subsection (f)(3)(D)(iii), the fuel factors to be used at the beginning of the price to beat period will be the fuel factor in effect on January 1, 1999, reduced by 6.0%, plus the difference between the fuel factors established under subsection (f)(3)(A), (B) and (C) and the fuel factor in effect on January 1, 1999. For purposes of clarity, the reference in proposed subsection (d) to subsection (f)(3)(A) has been changed to reference subsection (f)(3)(D).

**§25.41(e)**

TXU REP stated that there is no need to include additional language regarding refusal of service since Substantive Rule §25.477 of this title (relating to Refusal of Electric Service) of the proposed customer protection rules already addresses this subject. Entergy REP concurs with TXU REP.

The commission agrees with TXU REP and Entergy REP and has referred to §25.477 in subsection (e) to clarify the commission's intent.

TXU REP stated that with regard to term of service requirements of subsection (e)(1) and (2), TXU REP supports the use of a term of service option for commercial customers with a peak demand greater than 50 kW in order to prevent gaming. TXU REP stated that the language relating to refusal of service should be modified to allow an affiliated REP to refuse the provision of services to a small commercial customer with a peak demand of greater than 50 kW who was served by the affiliated REP within the prior 15 months, if the applicant is unwilling to accept either a one-year term of service with the affiliated REP or a price to beat rate under a Seasonal Adjustment Mechanism rider. Entergy REP stated that the rule should be modified to require a minimum one year or some other form of anti-gaming measure for returning PTB customers in order to protect the market from the harm created by competitive suppliers dumping customers back onto PTB service during high market cost months.

Reliant suggested that in order to address the gaming problem, aggregators and REPs, and their agents, be prohibited from offering incentives for customers to switch to the affiliated REP, and prohibited from serving as switching agents for the customers, whereby the agent can effectuate switching without further notice to customers. Switches that are found to have been the result of gaming would be reversed back to the date of the switch for settlement purposes. Further, Reliant proposed that affiliated REPs should have the right to initiate an investigation when they believe gaming by an aggregator or REP is occurring or has occurred.

ARM expressed support for the provisions of subsections (e)(1) and (2)(B) that prohibit affiliated REPs from requiring service agreements for PTB customers and from providing inducements to encourage PTB customers to agree to a term of service.

For reasons discussed in response to preamble Question 4 above, the commission disagrees with those commenters suggesting the addition of a minimum term contract or different seasonal rates for customers returning to the affiliated REP. The commission concludes that such provisions would very likely discourage customers from leaving the affiliated REP in the first place and thereby unnecessarily thwart the development of the competitive market. The commission has addressed the allowed measures to address the issue of gaming in its discussion of preamble Question 4 above.

Reliant suggested language to clarify that the customer is eligible for the price to beat on a going-forward basis and that the affiliated REP would not be required to restate the past 12 months bill. Entergy REP and TNMP supported this proposal.

The commission agrees with Reliant and has made their recommended language change to subsection (e)(2)(A).

TXU REP argued that language referring to the prohibition of "inducements" to encourage customers to agree to a term of service should be eliminated because the word "inducements" is too vague and would expose the affiliated REP to an undue risk of litigation.

ARM supported the proposed language in the rule and noted that the term inducements is no more vague than the term incentives included in the statute.

The commission agrees with ARM concerns and declines to make TXU REP's requested change.

TXU REP proposed that a new section should be added to the proposed rule in order to accommodate customer choice in choosing their contracted demand level when they order new service or when they add load at an existing service location. Entergy REP agreed with TXU REP that commercial customers with contract demand in excess of 1,000 kW should be allowed to enter into delivery contracts at competitive prices. However, Entergy REP did not believe that a new subsection is necessary, referencing subsection §25.41(e)(2)(A) of the proposed rule. ARM argued that this suggestion would open the door to all sorts of abuses and should be rejected. ARM stated that it would permit a customer and an affiliated REP to get around SB 7 provisions prohibiting affiliated REPs from charging anything but the price to beat to PTB customers in their service area and that it would be very difficult for the commission to monitor such abuses.

The commission agrees with ARM and Entergy REP that the proposed language adequately defines the eligibility of small commercial customers and is consistent with PURA §39.202(o), which defines small commercial customers through their actual peak demand, not their contracted demand. No change to this section has been made.

Entergy REP commented that references to the calendar year 2001, should be revised to the 12 consecutive months ending September 30, 2001, in order to alleviate doubt as to what customers are eligible for the PTB. TNMP concurred with Entergy REP.

The commission agrees with Entergy REP and TNMP that utilizing the 12 months ending September 30, 2001, will provide necessary advance notice to existing customers as to whether or not they are eligible for the price to beat. The commission has revised the rule to reflect this recommendation.

Entergy REP stated that the rule needed to be modified in order to prevent account-splitting abuse by customers in order to qualify for the price to beat. Entergy REP suggested that a customer who is ineligible for the PTB might split his account into several smaller sub-accounts in order to become eligible for the PTB.

The commission does not foresee account splitting in order to qualify for the price to beat being a major problem because customers larger than 1000 kW of demand should have access to more attractive rates than those provided under the price to beat. Under such circumstances, these customers would not logically attempt to split their accounts in order to qualify for the price to beat. Therefore, the commission declines to alter the proposed rule as suggested by Entergy REP. However, it is the commission's intention that the term "customer" refers to a metered point of delivery. Therefore, if there are several facilities behind a single meter, it would be inappropriate for each of the facilities to be considered a separate customer. However, if there are separately metered facilities on the same site, each facility would properly be considered a price to beat customer. The commission has modified the definition of small commercial customer in subsection (c)(9) accordingly.

**§25.41(f)(1)**

TXU REP opposed the elimination of rates that provide discounts and incentives for customers who make permanent changes to their consumption patterns, that develop new technologies, or that promote growth in economically depressed areas. AEP supported TXU REP's proposed revision. ARM opposed this position, stating that the Legislature intended the PTB to be a "plain, vanilla rate", not a competitive alternative. ARM commented that the price to beat rule should also include a provision explicitly prohibiting affiliated REPs from selling or marketing any "special" and/or "competitive-like" kinds of electricity services to PTB customers under the PTB, unless specifically required by commission rule. ARM proposed that the words "green" and "renewable" be included in the list of rates and riders for which PTB does not apply. Entergy REP and TLSC stated that the commission should clarify the rule to insure that low-income electric customers will continue to receive rate reductions under SB 7.

TXU REP suggested that new rates be introduced by a utility between January 1, 1999 and December 31, 2001 supporting the SB 7 goal for renewable power be eligible for PTB treatment. ARM opposes this position, stating that the Legislature intended the PTB to be a "plain, vanilla rate", not a competitive alternative.

The commission finds that, in order to be consistent with PURA §39.202(a) that the price to beat is to be based on bundled rates in effect on January 1, 1999, the affiliated REP should be required to offer a price to beat rate for every rate, tariff, and service option in effect on that date. However, the commission agrees with ARM that it is inappropriate to establish a PTB rate for new tariff options introduced after January 1, 1999, as PURA §39.202(a) specifically requires that the price to beat be based on bundled rates in effect on that date.

The commission agrees with ARM that it is inappropriate to allow affiliated REPs to offer "green" or "renewable" service offerings in their service territory, or to market price to beat service as a "green" or "renewable" product, unless such rates were in effect on January 1, 1999.

The commission does recognize that it may not be appropriate to develop a price to beat for certain rates, such as discounted rates or marginal cost based rates. As such, an electric utility, on behalf of its future affiliated REP should file tariffs for its price to beat rates within 60 days after the effective date of this rule. At the time of this filing, the utility may request that a price to beat not be developed for certain rates in effect on January 1, 1999.

Subsections (d)(2), (f)(1)(A), (f)(1)(B), and (f)(1)(C) of the rule have been modified accordingly.

TNMP stated that rather than applying the 6.0% rate reduction to each component of the rates, the rule should allow the price to beat to be calculated based on an average 6.0% decrease across the class. TNMP argued that this proposal complies with PURA and offers protection against the negative impacts that result from the skewed headroom between high usage and low usage customers. Consumer Commenters opposed the averaging of the 6.0% PTB decrease.

The commission concurs with Consumer Commenters. If the 6.0% decrease were averaged across all customers, there would be winners and losers. The commission concludes that it is appropriate to reduce base rates for each retail customer by 6.0% and as such, declines to change the rule as suggested by TNMP.

**§25.41(f)(2) and (3)**

Entergy REP recommended that the 60-day period be changed to 30 days because a 60-day average is too long to reflect current movements in the market and proposed changes to subsection (g)(1)(A) and (B) to shorten the time requirement from 60 days to 30-calendar days, and to use forward looking natural gas settlement prices for each season.

The Coalition agreed with AEP that the 60-day period is too long and would prevent any REP from being able to adequately hedge its purchases.

The commission concludes that it is appropriate to alter the period over which the average 12 month forward NMYEX gas price is averaged from a 60-day average to a ten-day average. Upon review of historical gas price data, the commission believes that the use of a 60-day average may result in too much of a lag from actual market prices. Use of a ten-day average should appropriately capture true trends in gas prices, while allowing adjustments to the fuel factor to better reflect changing market conditions and assist REPs in hedging their purchases.

Entergy REP proposed changes to subsection (f)(3)(D)(iii) as it determined that there should be no mandatory reduction of the fuel factor in effect on January 1, 1999, for Entergy REP. Entergy REP also proposed a new subsection (f)(3)(D)(iv) that states that "the fuel factors for affiliate electric utilities whose base rates were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, to be used at the beginning of the price to beat period shall be the fuel factor in effect on January 1, 1999, plus the difference between the fuel factors established pursuant to subparagraphs (A), (B) and (C) of this paragraph and the fuel factor in effect on January 1, 1999."

The commission agrees with Entergy REP and adds new subsection (f)(3)(D)(iv) to clarify that the fuel factors to be used at the beginning of the price to beat period for a utility whose base rates were reduced by more than 12% shall be the updated fuel factor established pursuant to subsection (f)(3)(D). The commission has also changed the incorrect reference in (f)(3)(D)(iii) from subparagraph (A), (B), and (C) to subparagraph (D).

Entergy REP also proposed a new subsection (f)(3)(E) that would state that the seasonal fuel factors established pursuant to subsection (f)(3) shall be known as the baseline fuel factors. In addition, Entergy REP raised several policy issues that it believed needed to be addressed and suggested that one or more technical conferences be conducted to address these issues and to gain consensus on these policy questions. Entergy REP's list of policy questions/issues is as follows:

1. What generation resources should be used to estimate the fuel factor?
2. Is there a "cut-off" date prior to the rate year to determine which utility owned generation resources are to be used in determining the fuel factor, what is that cut off date?
3. Should the date be unique for each utility?
4. What issues of fairness among the affiliate REPs are implicated if the date is different for each utility?
5. What estimate of sales should be used in the development of a fuel factor?
6. If the fuel factor is determined based on the estimate of total system sales, how is the load shape for non-price to beat sales adjusted out of the price to beat fuel factors?

7. In the case of those utilities that participate in a FERC-approved system agreement to allocate generation capacity and energy costs, are these resources to be included in determining eligible fuel expenses? If so, how?
8. If FERC approves withdrawal of a utility from participation in a FERC-approved system agreement effective prior to the rate year, how should the fuel factors be computed?
9. Are eligible non-generation related revenues/expenses to be considered? If so, how?
10. Must a utility seek a good cause exception for treatment of eligible non-generation related revenues/expenses different than the treatment of these revenues/expenses in current fuel factors?
11. How does FERC's order No. 2000 affect treatment of these revenues/expenses in the computation of fuel factors?

TXU REP also noted that for Southwestern Electric Service Company (SESCO), as a non-generating investor-owned utility, it had no fuel factor in January 1999. As such, TXU REP proposed that SESCO's purchased cost recovery factor (PCRF) in effect on January 1, 1999 should be used to calculate SESCO's initial price to beat fuel factor.

The commission finds, that as stated in subsection (f)(3)(B), the proper reading of PURA §39.202(b) is that the final fuel factor should be set in the traditional manner as outlined by the current fuel rule. While the commission recognizes that the inclusion of a fuel factor based on historical integrated utility fuel costs as part of the price to beat appears inconsistent with the market structure under SB 7, where REPs are prohibited from owning generation, the commission finds that the price to beat was intended to be calculated from the each utility's regulated rate in effect on January 1, 1999, discounted by 6.0% and updated for a final fuel factor. Utility-specific issues are to be addressed in the individual fuel factor cases, within the confines of this finding.

The commission agrees with TXU REP that the proper treatment of the fuel cost factor for SESCO, as a non-generating utility with no fuel factor, is that the PCRF in effect on January 1, 1999 should be used for the price to beat fuel factor. To the extent that SESCO's current purchased power contract expires during the price to beat period, TXU REP should at that time request an adjustment to SESCO's price to beat in order to account for the new contract.

The commission also clarifies that any previous commission orders that address how a utility's price to beat fuel factor is to be set should be given effect in the utility's fuel factor case.

**§25.41(g)**

Entergy REP recommended that subsection (g)(1) be modified so that an affiliate REP may request up to four changes in the seasonal fuel factors in a calendar year. Entergy REP stated that this approach comports with PURA §39.202(l) because §39.202(l) contemplates a single fuel factor and since the commission has established two seasonal fuel factors, then it is reasonable to allow two separate adjustments to each seasonal fuel factor.

The commission disagrees that that the statutory allowance of two changes per year can be read to allow more than two changes per year. No change has been made. See comments on preamble Question 1 for the commission's discussion of seasonality.

Cities proposed a change to subsection (g)(1)(A) to strike January 1, 2002, and replace it with September 15, 2001.

The commission has made revisions to subsection (g)(1)(A) to clarify how the methodology for calculating an adjustment to the fuel factor should work. While the commission declines to adopt Cities' proposed change, the commission believes that the changes made in this subsection should address the concerns raised by Cities.

AEP commented that the procedural schedule referenced in subsection (g)(1)(D) should be revised to shorten the length of time it takes to obtain a final order on fuel factor revision applications. AEP supported TNMP's proposal that the procedural schedule be revised to require the issuance of an order within 20 days after a petition is filed if no hearing is requested and 45 days after a petition is filed if a hearing is requested within 15 days of the petition.

TNMP suggested changes to subsection (g)(1)(D) as well. TNMP proposed that in addition to the adjustment specified in the proposed rule, additional language be added that would allow the REP to recover the disparity during the period before the adjustment is implemented. TNMP contends this adjustment is necessary because the regulatory framework provides neither a mechanism for recovering the loss if the affiliated REP's costs rise, nor a policy basis for requiring affiliated REPs to absorb this loss. TNMP also requested adjustments to the proposed procedural process for adjustments to the fuel factor. TNMP stated that these adjustments are necessary because the current fuel rule would subject affiliated REPs to a 90-day delay and could cause additional losses of millions of dollars. TNMP requested that the procedural schedule be modified to require that an order be issued within 20 days after the petition is filed, if no hearing is requested within 15 days of the petition and within 45 days after the petition is filed if a hearing is requested within 15 days of the petition. If a hearing is requested, TNMP recommended, the hearing should be held no earlier than the first business day after the 25th day after the application is filed.

The commission finds that, for the purposes of an adjustment to the fuel factor resulting from a change in the NYMEX gas price index, TNMP's proposed procedural schedule is appropriate. For adjustments to the fuel factor under subsection (g)(1)(E) based on changes in headroom resulting from significant changes in the price of purchased energy, the commission will issue a final order within 60 days after an application is filed under this subsection. The commission disagrees with TNMP that an affiliated REP is entitled to recover any loss incurred during the process of evaluating a requested change as PURA does not contemplate any reconciliation of the price to beat and market prices, except during the 2004 true-up.

Adjustments to the price to beat based on financial integrity have the potential to be lengthy, contested cases. The commission therefore declines at this time to establish in the rule any procedural deadlines for such proceedings. The procedural schedule for a change in the price to beat due to financial integrity is more appropriately addressed on a case-by-case basis.

TXU REP proposed to eliminate subsection (g)(1)(E) that restricts the dates when the fuel adjustment can be filed. TNMP suggested that the 45-day requirement of subsection (g)(1)(E) be eliminated or that this requirement be changed to 120 days to allow the affiliated REP to delay an available adjustment to preserve for itself the option of seeking an adjustment at a subsequent time of the year.

The commission has revised subsection (g)(1)(E) of the rule in a manner that should address TXU REP's and TNMP's concerns.

**§25.41(h)**

TXU REP suggested revising subsections (h)(1) and (h)(2) to include language that an affiliated REP may not offer rates other than the price to beat rates to residential and small commercial customers in its "service area," at least not until the commission determines that "40% or more of the electric power consumed by residential customers within the affiliated electric utility's certificated service area before the onset of customer choice is committed to be served by nonaffiliated retail electric providers."

Entergy REP stated that an interpretation of §25.41(h)(1) would encompass all affiliated REPs in all service territories so that an affiliated REP would have to offer the price to beat wherever it had customers and proposed adding the following language to the above section and also subsection (h)(2): "...in its affiliated transmission and distribution utility's certificated service territory...." TNMP in its reply comments supported Entergy REP's clarification in the above subsection. In addition, Entergy REP agreed with TXU REP's proposal for §25.41(h).

The commission agrees with TXU REP and Entergy REP and has revised this subsection of the rule accordingly.

Entergy REP in its reply comments proposed adding the following language at the end of subsection (h)(1): "except as provided by the rate reduction program of the commission rules relating to the System Benefit Fund."

The commission agrees with Entergy REP and has made the corresponding change in subsection (h)(1).

ARM commented that the exception under subsection (h)(3) be strictly construed and reviewed by the commission to preclude misuse by the affiliated REPs; also, the commission should require a filing by the affiliated REPs to show that the customers are above 1000 kW, are commonly owned, or are of the same franchisor and could approve such filing within 30 days if there are no objections. ARM proposed that the subsection be revised accordingly. Entergy REP in its reply suggested rejecting ARM's proposal regarding aggregation exception because it is not authorized under PURA §39.202(f). Reliant in its reply disagreed with ARM regarding the need to file proof that aggregated small commercial loads charged non-PTB rates are eligible for such rates because it would place unnecessary burden on the affiliated REPs. TXU REP in its reply opposed ARM's proposal to prove eligibility of the aggregated load to receive rates other than the price to beat because it exceeds the authority allowed under PURA and the commission already has authority to investigate any complaints about improper activity.

The commission agrees with ARM and will require the affiliated REP to make an informational filing for customers who qualify for this exemption. The commission has amended subsection (l)(3) to reflect this requirement.

**§25.41(i)**

TXU REP commented that the proposed methodology cannot be implemented and that both the threshold target concept and specific language would have to be altered to be workable. The company stated that the idea of establishing a consumption baseline is a reasonable one and that it should be used as a means against which to calculate the 40% loss of load, and not as a target threshold, which cannot be established by June 1, 2001. TXU REP also stated that both residential and small commercial consumption should be addressed in the same manner; and that the following subsections should be renamed: (i) - "Calculation of baseline consumption for calendar year 2000," (i)(1) - "Calculation of baseline consumption," (A) and (B) – "Residential baseline" and "Small commercial baseline." Additionally, language about the 40% target should be deleted from these two subparagraphs, and added to subsections (h)(1) and (h)(2); and the "Small commercial baseline" section should be revised to require establishment of a small commercial customer baseline served in 2000, with no subtractions for ineligible customers, and the actual 40% target should be calculated after competition begins. TXU REP also noted a problem in subsection (i)(1)(B), in which 40% of the aggregated load from 2000 consumption of small commercial class is deducted and not 100% as required by PURA; however, no changes are needed as other proposed changes would correct this one. If not, TXU REP and Reliant proposed to delete "times 40%" in subsection (i)(1)(B).

TXU REP commented that dividing total consumption by one-twelfth of the number of bills does not produce an accurate calculation of the number of customers because each customer may receive more than one bill. A more accurate method to determine the average number of customers would be to count customers once each month for twelve months and then calculate the average over twelve months. TXU REP suggested modifying subsection (i)(2)(A)(ii) to reflect the above comments. Reliant in its reply agreed with TXU REP that the consumption threshold target cannot be calculated with certainty on June 1, 2001, and supported the proposal to establish a consumption baseline and changes to subsection (h).

In its reply, Entergy REP agreed with TXU REP regarding computation of average consumption and opposed using the number of bills in the computation. Entergy REP also opposed Consumer Commenters' method of counting switches, partly because some customers may be dropped to the POLR simply because their REP decides to leave the state; therefore all switches should be counted toward the threshold target.

The commission agrees with TXU REP and Entergy REP that it is more appropriate to use number of customers in the calculation of average usage as opposed to one-twelfth of the number of bills due to re-billings, etc. The commission also agrees with TXU REP and Reliant that there is a double application of the 40% in subsection (i)(1)(B) and corrects that subparagraph. The commission also recognizes TXU REP's concern regarding the establishment of target thresholds by June 1, 2001 given the uncertainty about what commonly-owned franchisee aggregated load may qualify and pursue an exemption under the rule. As such, the commission moves the initial filing date from June 2001 to

December 2001 and requires updates to the small commercial threshold, as load is deemed eligible for the exemption.

TXU REP, SPS, TNMP in its reply, and Reliant opposed the exclusion of customers served by POLR from the target calculation and stated that the concern that an affiliated REP may terminate customers just to meet the 40% loss is unsubstantiated because the customer protection rules have detailed procedures on how terminations are to be done. Additionally, TXU REP stated that if the POLR customers are not to be counted because of an assumption that those customers have not exercised their market choice, this may not be accurate because some customers could voluntarily choose POLR or be dropped to POLR after having switched to a non-affiliated REP. TXU REP also argued that even if the affiliated REP drops a customer to the POLR, this is based on the same concept of choice embodied in SB 7, because this customer "chose" not to pay their bill. Also, TXU REP and Entergy REP stated that the law did not provide for this exclusion because it specified 40% or more served by "non-affiliated" REPs; however, if the POLR is the affiliated REP, then the customers should still count because the affiliated REP is not a POLR by choice.

Consumer Commenters stated that POLR customers should not count toward calculating the threshold. Consumer Commenters further noted that the commission should ensure that those customers who switch to the non-affiliated REP and then switch back to the affiliated REP are not counted since the threshold number should represent a point in time and not a cumulative number of switches.

In its reply, ARM stated that in spite of opposition by Reliant and other utilities, §25.41(i) should be adopted because gaming could still go on, only those customers who choose a provider should be counted, and the POLR is not a competitive provider. ARM opposes Reliant's proposal to establish a process for approving the affiliated REPs' target threshold filings; instead current procedural rules should apply. If a different timeline is adopted, then there should be sufficient time for a contested hearing. ARM also disagrees with the Reliant's suggestion to require a minimum term for small commercial customers on the PTB.

In their replies, Shell and OPC argued that the utilities' arguments for the 40% target calculation to include POLR customers should be rejected because those customers did not exercise choice regarding their provider.

The commission rejects utilities' arguments regarding counting customers dropped to the POLR and will not count them as "switches." The rationale for creating the POLR was to have an electric provider for those customers who may have difficulty exercising choice in the competitive market. Therefore, dropping customers to the POLR should not be considered a sign of a well functioning competitive market. Additionally, the commission agrees with Consumer Commenters that the threshold number is a snapshot in time and not a cumulative number of switches. No change in the language has been made. The commission finds that the current procedural rules should apply to the process of approving affiliated REPs' target threshold filings.

OPC proposed to revise §25.41(i)(2)(A) to say: "The amount of electric power consumed by residential customers *served* by non-affiliated REPs shall equal...."

The commission agrees and has made the requested change.

Reliant recommended that the commission require filings pursuant to §25.41(i)(2) be made jointly by the transmission and distribution utility (TDU) and the affiliated REP.

The commission finds that PURA explicitly requires the TDU to make filings to show that its affiliated REP has met the threshold. The TDU will have meter data for all customers, and will also know who the customers' REPs are. The commission therefore declines to adopt Reliant's suggestion.

Entergy REP asked for a clarification regarding §25.41(i)(1)(B) because PURA implies that the variable component in this subsection (i.e., the aggregated load served by the affiliated REP that complies with the requirements of (h)(3)) is to be counted prior to competition, thus removing it from the equation. Entergy REP also proposed deleting "times 40%" from subsection (i)(1)(B). ARM commented that the affiliated REP should be required to file information about customers and load that is deemed to qualify for the aggregated load exemption, as such an exemption is susceptible to gaming by the affiliated REP.

As stated above, the commission agrees with the concerns about the calculation of the small commercial threshold and has (1) moved the filing of the initial calculation to the end of 2001; and (2) required updates to the small commercial threshold calculation as load qualifies for the exemption and is served by the affiliated REP at a rate other than the price to beat rates. The commission also agrees with ARM that the affiliated REP should make an informational filing with the commission specifying the customer's name, premise identifications, size of customer's load, and how the customers qualify for the exemption. The affiliated REP may file such information under confidential seal, however, all certified REPs will be deemed to have standing to examine these filings. This section of the rule has been modified accordingly.

Entergy REP suggested changes to specify that a REP can not offer incentives to its customers to switch and can not promote competitors' interests or exchange customers with other REPs. Consumer Commenters went further to suggest that there be a prohibition against an affiliated REP offering any incentive or encouragement to competitors to get customers to switch to a nonaffiliated REP, in order to reach the 40% threshold sooner.

Consumer Commenters supported disclosure of the PTB. TXU REP, however, objected to the disclosure and offered the following two alternatives: (1) delete any language about disclosing the PTB when offering a higher price service; (2) only state the existence of a PTB when offering a higher priced service. TXU REP's based its objection on the requirement being "burdensome," because it would require printing multiple versions of customer education materials in order to include the specific price to beat rates for which particular customers would be eligible. Also, TXU REP felt it would be unnecessary because it might be as much as 36 months before some affiliated REPs could charge any rates other than the price to beat.

The commission disagrees with TXU REP's assumption that these disclosure requirements are burdensome. The REP will be required to provide an electricity facts label and other documents for every rate it offers; therefore, the commission determines that it will not be burdensome for the affiliated REP to add an additional column indicating the price to beat and a statement informing the customer that they are eligible for another rate. The commission also disagrees with TXU REP's proposal to state only the existence of the price to beat because not all customers are aware of the price to beat for one reason or another. For example, a customer moving from out of state would be unaware of the price to beat and may believe they have no choice. Therefore, the commission concludes that the language shall remain unchanged.

Reliant recommended that filings under subsections (i) and (l)(2) regarding power consumption threshold targets be made jointly by the transmission and distribution utility and the affiliated REP. In addition, Reliant recommended that a process for approving such filings under subsection (l) be established; specifically, that commission staff's review, recommendation and final approval be achieved within 60 days of the filing.

The commission finds that the statute specifies that the distribution utility make the filings; there is no need for the REP to be involved.

TXU REP objected to subsection (l)(2), which requires a warning filing when a 35% load loss has occurred. It believes that this requirement is burdensome, unnecessary and not authorized by SB 7. TXU REP suggested that the commission utilize reports produced by ERCOT to track the level of switching. Reliant agrees that this warning requirement is not necessary.

The commission disagrees with TXU REP and Reliant and notes that the commission only has 30 days to accept or reject this filing. The 35% filing is merely a informational report that an affiliated REP is approaching the 40% target.

Entergy REP stated that because ERCOT would not have load/use data on non-ERCOT customers, verification under subsection (l)(4)(C) would be difficult and costly.

The commission notes that the ERCOT ISO will be acting as the registration agent for all utilities in the state of Texas, and as such, should be able to provide information as to how many and which customers have switched to an alternate provider. Subsection (l)(4)(C) details certain other requirements for small commercial customers in excess of 20 kW that will be needed to verify an affiliated REP's claim that they have reached the 40% load loss threshold. No report from ERCOT is required under the section. The commission declines to modify the rule.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

This new section is adopted under the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2001), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction, and §39.202 which establishes the price to beat obligation for affiliated retail electric providers.

Cross Reference to Statutes: PURA §§14.002, 39.152, 39.202, 39.262, and 39.406.

**§25.41. Price to Beat.**

(a) **Applicability.** This section applies to all affiliated retail electric providers (REPs) and transmission and distribution utilities, except river authorities. This section does not apply to an electric utility subject to Public Utility Regulatory Act (PURA) §39.102(c) until the end of the utility's rate freeze.

(b) **Purpose**. The purpose of this section is to promote the competitiveness of the retail electric market through the establishment of the price to beat that affiliated REPs must offer to retail customers beginning on January 1, 2002 pursuant to PURA §39.202.

(c) **Definitions.** The following words and terms, when used in this section, shall have the following meanings, unless the context indicates otherwise:

(1) **Affiliated electric utility** — The electric utility from which an affiliated REP was unbundled in accordance with PURA §39.051.

(2) **Competitive retailer** — A REP or a municipally owned utility or distribution cooperative that offers customer choice in the restructured competitive electric power market or any other entity authorized to sell electric power and energy at retail in Texas.

(3) **Headroom** — The difference between the average price to beat (in cents per kilowatt hour (kWh)) and the sum of the average non-bypassable charges or credits approved by the commission in a proceeding pursuant to PURA §39.201, or PURA Subchapter G (in cents per kWh) and the representative power price (in cents per kWh). Headroom may be a positive or negative number. A separate headroom number shall be calculated for the typical residential customer and the typical small commercial customer. The calculation for the typical residential customer shall assume 1,000 kWh per month in usage. The calculation of the typical small commercial customer shall assumer 35 kilowatts (kW) of demand and 15,000 kWh per month in usage.

(4) **Nonaffiliated REP** — Any competitive retailer conducting business in a transmission and distribution utility's (TDU's) certificated service territory that is not affiliated with that TDU.

(5) **Peak demand** — The highest 15-minute or 30-minute demand recorded during a 12-month period.

(6) **Price to beat period** — The price to beat period shall be from January 1, 2002 to January 1, 2007. In a power region outside the Electric Reliability Council of Texas (ERCOT) if customer choice is introduced before the date the commission certifies the power region pursuant to PURA §39.152(a) are met, the price to beat period continues, unless changed by the commission in accordance with PURA Chapter 39, until the later of 60 months after the date customer choice is introduced in the power

region or the date the commission certifies the power region as a qualified power region.

(7) **Provider of last resort (POLR)** — As defined in §25.43 of this title (relating to Provider of Last Resort).

(8) **Registration agent** — As defined in §25.454 of this title (relating to Rate Reduction Programs).

(9) **Representative power price**. The simple average of the results of:

(A) a request for proposals (RFP) for full-requirements service of 10% of price to beat load for a duration of three years expressed in cents per kWh; and

(B) the price resulting from the capacity auctions required by PURA §25.381 of this title (relating to Capacity Auctions) for baseload capacity entitlements expressed in cents per kWh. The calculation of the price resulting from the capacity auctions shall assume dispatch of 100% of the entitlement and shall use the most recent auction of a 12-month forward strip of entitlements, or the most recent aggregated forward 12 months of entitlements.

(10) **Residential customer** — Retail customers classified as residential by the applicable transmission and distribution utility tariff or, in the absence of classification under a residential rate class, those retail customers that are primarily end users consuming electricity for personal, family or household purposes and who are not resellers of electricity.

(11) **Small commercial customer** — A non-residential retail customer having a peak demand of 1,000 kilowatts (kW) or less. For purposes of this section, the term small commercial customer refers to a metered point of delivery. Additionally, any non-metered point of delivery with peak demand of less than 1,000 kW shall also be considered a small commercial customer.

(12) **Transmission and distribution utility** — As defined in §25.5 of this title (relating to Definitions), except for purposes of this section, this term does not include a river authority.

(d) **Price to beat offer.**

(1) Beginning with the first billing cycle of the price to beat period and continuing through the last billing cycle of the price to beat period, an affiliated REP shall make available to residential and small commercial customers of its affiliated transmission and distribution utility rates that, subject to the exception listed in subsection (f)(2)(A) of this section, on a bundled basis, are 6.0% less than the affiliated electric utility's corresponding average residential and small commercial rates that were in effect on January 1, 1999, adjusted to reflect the fuel factor determined in accordance with subsection (f)(3)(D) of this section and adjusted for any base rate reduction as stipulated to by an electric utility in a proceeding for which a final order had not been issued by January 1, 1999.

(2) Unless specifically required by commission rule, an affiliated REP may only sell electricity to price to beat customers labeled or marketed as "green," "renewable," "interruptible," "experimental," "time of use," "curtailable," or "real time," if and only if such a tariff option existed on January 1, 1999 and only for service under the price to beat rate that was developed from that tariff.

(e) **Eligibility for the price to beat.** The following criteria shall be used in determining eligibility for the price to beat:

(1) **Residential customers.** All current and future residential customers, as defined by this section, shall be eligible for the price to beat rate(s) for which they meet the eligibility criteria in the applicable price to beat tariffs for the duration of the price to beat period. An affiliated REP may not refuse service under the price to beat to a residential customer except as provided by §25.477 of this title (relating to Refusal of Service). An affiliated REP may not require residential customers to enter into service agreements with a term of service as a condition of obtaining service under the price to beat, nor may an affiliated REP provide any inducements to encourage customers to agree to a term of service in conjunction with service under the price to beat.

(2) **Small commercial customers.**

(A) A non-residential customer taking service from the affiliated electric utility on December 31, 2001, shall be considered a small commercial customer under this section and shall be eligible for service under price to beat tariffs if that customer's peak demand during the 12 consecutive months ending on September 30, 2001, does not exceed 1,000 kilowatts (kW). A non-residential customer with a peak demand in excess of 1,000 kW during the 12 months ending September 30, 2001, or during the price to beat period, shall no longer be considered a small commercial customer under this section. However, any non-residential customer whose peak demand does not exceed 1,000 kW for any period of 12 consecutive months after it became ineligible to be a small commercial customer under this section shall be considered a small commercial customer for billing periods going forward for purposes of this section.

(B) All small commercial customers, as defined by this section, shall be eligible for the price to beat rate(s) for which they meet the eligibility criteria in the applicable price to beat tariffs for the duration of the price to beat period. An affiliated REP may not refuse service under the price to beat to a small commercial customer, except as provided by §25.477 of this title. An affiliated REP may not require small commercial customers to enter into service agreements with a term of service as a condition to obtaining service under the price to beat, nor may an affiliated REP provide any inducements to encourage customers to agree to a term of service in conjunction with service under the price to beat.

(f) **Calculation of the price to beat.**

(1) **Rates to be used for price to beat calculation.** The following criteria shall be used in determining the rates to be used for the price to beat calculation.

(A) Residential. A price to beat rate shall be calculated for each rate and service rider under which a residential customer was taking service on January 1, 1999, except as approved by the commission pursuant to subparagraph (C) of this paragraph. A price to beat rate shall not be calculated for any new service or tariff option granted to an affiliated electric utility pursuant to PURA §39.054, or any other rate or tariff option not in effect on January 1, 1999.

(i) Beginning with the first full billing cycle of the price to beat period, residential customers served by the affiliated REP shall be placed on the price to beat rate derived from the rate under which they were taking service on December 31, 2001.

(ii) Beginning with the first full billing cycle of the price to beat period, residential customers served by the affiliated REP who were taking service under a rate for which a price to beat rate was not developed, shall be placed on the price to beat rate derived from any eligible residential rate that was or would have been available to the customer on January 1, 1999.

(iii) New residential customers after December 31, 2001, may choose any price to beat rate for which they meet the eligibility requirements as detailed in the applicable price to beat tariff.

(iv) Residential customers who return to the affiliated REP after being served by a non-affiliated REP may choose any price to beat for which they meet the eligibility requirements as detailed in the applicable price to beat tariff(s).

(v) Notwithstanding clauses (i) – (iv) of this subparagraph, residential customers may request service under any price to beat rate for which they are eligible. Selection of the most advantageous rate shall be the sole responsibility of the residential customer.

(B) Small commercial. A price to beat rate shall be calculated for each rate and service rider under which a small commercial customer was taking service on January 1, 1999, except as approved by the commission pursuant to subparagraph (C) of this paragraph. A price to beat rate shall not be calculated for any new service or tariff option granted to an affiliated electric utility pursuant to PURA §39.054, or for any rate of tariff option not in effect on January 1, 1999.

(i) Beginning with the first full billing cycle of the price to beat period, small commercial customers served by the affiliated REP shall be placed on the price to beat rate derived from the rate under which they were taking service on December 31, 2001.

(ii) Beginning with the first full billing cycle of the price to beat period, small commercial customers served by the affiliated REP beginning in January of 2002, who were taking service under a rate for which a price to beat rate was not developed, shall be placed on a price to beat rate derived from an eligible rate that was or would have been available to the customer on January 1, 1999.

(iii) New small commercial customers after December 31, 2001, may choose any price to beat rate for which they meet the eligibility requirements as detailed in the applicable price to beat tariff.

(iv) Small commercial customers who return to the affiliated REP after being served by a non-affiliated REP may choose any price to beat rate for which they meet the eligibility requirements as detailed in the price to beat tariff(s).

(v) Notwithstanding clauses (i) – (iv) of this subparagraph, small commercial customers may request service under any price to beat tariff for which they are eligible. Selection of the most advantageous rate shall be the sole responsibility of the small commercial customer.

(C) An electric utility, on behalf of its future affiliated REP, shall file within 60 days of the effective date of this section, price to beat tariffs and supporting workpapers for the price to beat rates developed in accordance with subparagraphs (A) and (B) of this paragraph. At the time of this filing, the affiliated REP may request that a price to beat rate not be developed from a particular rate of service rider along with justification for the request. The electric utility shall provide notice to all customers currently taking service under such rates or service riders of the utility's request.

(2) **Base rate component of price to beat.** For the eligible rates identified in paragraph (1) of this subsection, the affiliated REP shall reduce each base rate component including any purchased power cost recovery factor (PCRF), in effect for the affiliated electric utility on January 1, 1999, by 6.0% in order to determine the base rate component of the price to beat, with the following exceptions:

(A) If base rates for the affiliated electric utility were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, then the price to beat shall be the rate in effect as a result of a settlement approved by the commission after January 1, 1999.

(B) For affiliated REPs operating in a region defined by PURA §39.401, the commission may reduce rates by less than 6.0% if the commission determines a lesser reduction is necessary and consistent with the capital requirements needed to develop the infrastructure necessary to facilitate competition among electric generators.

(C) Except as provided in subparagraphs (A) and (B) of this paragraph, for any affiliated electric utility that has stipulated to rate reductions in a proceeding for which a final order had not been issued by January 1, 1999, such rate reductions shall be deducted from the base rates in effect on January 1, 1999, in addition to the 6.0% reduction. Such rate credits shall also be applied to the rates of the transmission and distribution utility.

(3) **Fuel factor component of price to beat.**

(A) Each affiliated electric utility shall file an application to establish one or more fuel factors, to be effective on January 1, 2002, according to the following schedule:

(i) April 1, 2001 - Reliant Houston Lighting & Power;

(ii) May 1, 2001 - TXU Electric Company;

(iii) June 1, 2001 - Texas-New Mexico Power Company and Central Power & Light Company;

(iv) July 1, 2001 - Entergy Gulf States, Inc. and West Texas Utilities;

(v) August 1, 2001 - Southwestern Electric Power Company and Southwestern Public Service Company.

(B) The rate year for the filing shall be calendar year 2002. The affiliated electric utility shall follow the requirements of §25.237(a)(1), (b), (c) and (e) of this title (relating to Fuel Factors) and the Fuel Factor Filing Package of November 23, 1993, for the filing of its fuel factor(s). To the extent that the commission has issued an order for a utility that includes provisions relating to the price to beat fuel factor, the price to beat fuel factor shall be set consistent with such an order.

(C) Subject to the limitations in clause (i) and (ii) of this subparagraph, affiliated electric utilities may utilize seasonal fuel factors to reflect the expected differences in the cost of the market price of electricity throughout the year.

(i) Affiliated electric utilities with seasonal fuel factors in effect on or before March 1, 2001, may request seasonal fuel factors for their residential and small commercial price to beat customers provided the level of seasonality is identical to that reflected in its commission-approved fuel factors on March 1, 2001.

(ii) Affiliated electric utilities without seasonal fuel factors in effect on or before March 1, 2001, may request seasonal fuel factors to be applicable to small commercial price to beat customers only. Any request for seasonal fuel factors under this clause must demonstrate that the average small commercial customer will receive, on an annual basis, a 6.0% reduction from the average bundled rate in effect on January 1, 1999, adjusted for the final fuel factor determined under subparagraph (D) of this paragraph; provided, however, that a utility subject to the exception in paragraph (2)(A) of this subsection must demonstrate that the average small commercial customer will receive, on an annual basis, the average bundled rate in effect as the result of a settlement approved by the commission after January 1, 1999, adjusted for the final fuel factor determined under subparagraph (D) of this paragraph.

(D) Each affiliated electric utility shall file additional information on October 1, 2001, to reflect changes in the price of natural gas for the rate year of 2002. The affiliated electric utility shall also file information necessary to determine the initial headroom that exists under the price to beat as a result of the setting of the initial price to beat fuel factor pursuant to this subparagraph. The adjustment shall be calculated using the following methodology:

(i) For the ten-day period ending on September 15, 2001, an average price shall be calculated for each month of 2002 in the closing forward

NYMEX Henry Hub natural gas prices, as reported in the Wall Street Journal.

(ii) All other inputs into the calculation of the fuel factors will be the same as those used to calculate the fuel factor in subparagraphs (B) and (C) of this paragraph.

(iii) Except for affiliated electric utilities whose base rates were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, the fuel factor(s) to be used at the beginning of the price to beat period shall be the fuel factor in effect on January 1, 1999, reduced by 6.0%, plus the difference between the fuel factor(s) established pursuant to this subparagraph and the fuel factor in effect on January 1, 1999.

(iv) The fuel factor(s) for affiliate electric utilities whose base rates were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, to be used at the beginning of the price to beat period shall be the fuel factor(s) established pursuant to this subparagraph.

(E) For a non-generating investor-owned utility with no fuel factor as of January 1, 1999, its PCRF in effect on January 1, 1999, shall be the equivalent to a fuel factor for purposes of calculating its price to beat rates and future fuel cost adjustments under subsection (g) of this section. Upon expiration of a purchased power contract of an affiliated REP unbundled from such a utility, the affiliated REP may request a change in its PCRF to account for any difference in purchased power costs.

(g) **Adjustments to the price to beat.**

(1) **Fuel factor adjustments.** An affiliated retail electric provider may request that the commission adjust the fuel factor(s) established under subsection (f)(3) of this section not more than twice in a calendar year if the affiliated retail electric provider demonstrates that the existing fuel factor(s) do not adequately reflect significant changes in the market price of natural gas and purchased energy used to serve retail customers. As part of a filing made pursuant to this paragraph, an affiliated REP may also request an adjustment to the seasonality imparted to the fuel factor in accordance with subsection (f)(3)(C) of this section. Alternatively, the commission may, as part of its approval of an adjustment to the fuel factor, impose a change in the seasonality imparted to the fuel factor. The methodology for calculating the adjustment to the fuel factor(s) shall be the following:

(A) For each business day of the ten-day period ending no more than ten business days before the filing of a fuel factor adjustment application, an average of the closing forward 12-month NYMEX Henry Hub natural gas prices, as reported in the *Wall Street Journal*, is calculated.

(B) The average forward price for each business day calculated in subparagraph (A) of this paragraph will then be averaged to determine a ten-day rolling price.

(C) The percentage difference between the averaged ten-day rolling price calculated under subparagraphs (A) and (B) of this paragraph and the averaged ten-day rolling price used to calculate the current fuel factor(s) is calculated. If the current fuel factor was calculated through an adjustment under subparagraph (E) of this paragraph, then the averaged ten-day rolling price calculated concurrent with that adjustment shall be used. If the percentage difference is 4.0% or more, the current fuel factor(s) may be adjusted.

(D) To adjust the current fuel factor(s), the percentage difference is added to one and then multiplied by the current factor(s). The results are the adjusted fuel factor(s) that will be implemented according to the procedural schedule in clause (i) and (ii) of this subparagraph:

(i) if no hearing is requested within 15 days after the petition has been filed, a final order shall be issued within 20 days after the petition is filed;

(ii) if a hearing is requested within 15 days after the petition is filed, a final order shall be issued within 45 days after the petition is filed.

(E) In addition to the adjustment permitted under subparagraphs (A)-(D) of this paragraph, an affiliated REP may also request an adjustment to the fuel factor if the headroom under the price to beat decreases as a result of significant changes in the price of purchased energy. In making a request under this subparagraph:

(i) an affiliated REP shall demonstrate that:

(I) the representative power price has changed such that the headroom under the price to beat has decreased; and

(II) the adjustment to the fuel factor is necessary to restore the amount of headroom that existed at the time that the initial price to beat fuel factor was set by the commission using then current forecasts of the representative power price.

(III) an affiliated REP making an adjustment under this subparagraph shall also file the gas price calculation in subparagraphs (A) and (B) of this paragraph for purposes subsequent adjustments to the fuel factor based on changes in natural gas prices.

(ii) the commission will issue a final order on an application filed under this subparagraph within 60 days after the application is filed.

(F) The commission shall, upon a showing made by an interested party, that a sufficiently liquid electricity commodity index has developed for the affiliated REP's relevant power region, allow an affiliated REP to transition to the use of an electricity commodity index to adjust the fuel factor for significant changes in the price of purchased energy. The commission shall only allow the use of the index after the power generation company affiliated with the affiliated REP has finalized their stranded cost determination. After the commission has made a finding that a sufficiently liquid electricity commodity index has developed, the affiliated REP shall be required to perform an additional adjustment under subparagraphs (A) through (D) or (E) of this paragraph before utilization of the index to change the fuel factor so that a benchmark index price can be established. Subsequent changes to the fuel factor shall be based on the percentage change in the electricity commodity index.

(2) **Adjustment for financial integrity.** Upon a finding that an affiliated REP will be unable to maintain its financial integrity if it complies with subsection (f) of this section, the commission shall set the affiliated REP's price to beat at the minimum level that will allow the affiliated REP to maintain its financial integrity. However, in no event shall the

price to beat exceed the level of rates, on a bundled basis, charged by the affiliated electric utility on September 1, 1999, adjusted for fuel.

(3) **True-up adjustment.** The commission may adjust the price to beat following the true-up proceedings under PURA §39.262.

(h) **Non-price to beat offers.**

(1) **Offers to residential customers.** An affiliated REP may not offer any rates other than the price to beat rates to residential customers within the affiliated electric utility's service area until the earlier of 36 months after the date customer choice is introduced, or when the commission determines that an affiliated REP has met or exceeded the threshold target for residential customers described in subsection (i) of this section, except as provided by §25.454 of this title (relating to Rate Reduction Program).

(2) **Offers to small commercial customers.** An affiliated REP may not offer rates other than the price to beat rates to small commercial customers until the earlier of 36 months after the date customer choice is introduced, or when the commission determines that an affiliated REP has met or exceeded the threshold target for small commercial customers described in subsection (i) of this section.

(3) **Offers to aggregated small commercial load.** Notwithstanding paragraph (2) of this subsection, an affiliated REP may charge rates different from the price to beat for service to aggregated loads having an aggregated peak demand in excess of 1,000 kW

provided that all affected customers are commonly owned or are franchisees of the same franchisor.

(A) If aggregated customers whose loads are served by an affiliated REP in accordance with this subsection disaggregate, those individual customers may resume service under the applicable price to beat rate(s), provided that those customers meet the eligibility requirements of subsection (e) of this section.

(B) Any usage removed from the threshold calculation in subsection (i)(1)(B) of this section due to aggregation shall be added back into the threshold calculation upon disaggregation of the aggregated load.

(i) **Threshold targets.**

(1) **Calculation of threshold targets.**

(A) Residential target. The residential threshold target shall be equal to 40% of the total number of kilowatt-hours (kWh) consumed by residential customers served by the affiliated electric utility during the calendar year 2000.

(B) Small commercial target. The small commercial threshold target shall be equal to 40% of the following difference: the total number of kWh consumed by small commercial customers served by the affiliated electric utility during the calendar year 2000 minus the aggregated load served by the affiliated REP that complies with the requirements of subsection (h)(3) of this section. The kWh associated with a customer who becomes ineligible for the price to beat because the customer's peak demand exceeds 1,000 kW shall also be removed from the threshold target.

(2) **Meeting of threshold targets.** Upon a showing by the affiliated transmission and distribution utility that the electric power consumption of the relevant customer group served by nonaffiliated REPs meets or exceeds the targets determined by the calculation in paragraph (1) of this subsection, the affiliated REP may offer rates other than the price to beat.

(A) Calculation of residential consumption. The amount of electric power of residential customers served by nonaffiliated REPs shall equal the number of residential customers served by nonaffiliated REPs, except customers that the affiliated REP has dropped to the POLR, times the average annual consumption of residential customers served by the affiliated utility during the calendar year 2000.

(i) The number of customers served by nonaffiliated REPs shall be determined by summing the number of customers in the transmission and distribution utility's certificated service area with a designated REP other than the affiliated REP in the registration database maintained by the registration agent. Customers dropped to the POLR by the affiliated REP shall not count as load served by a nonaffiliated REP.

(ii) The average annual consumption shall be calculated by dividing the total kWh consumed by residential customers during the calendar year 2000 by the average number of residential customers during the calendar year 2000. The average number of residential customers during the calendar year 2000 shall be calculated by dividing the sum of the total number of such customers for each month of the year 2000 by 12.

(B) Calculation of small commercial consumption. The amount of electric power consumed by small commercial customers served by nonaffiliated REPs shall be determined using the following criteria, except that customers served by the POLR shall not count as load served by a nonaffiliated REP:

(i) The amount of electric power of small commercial customers with peak demand less than 20 kW consumed by nonaffiliated REPs shall be equal to the number of small commercial customers with peak demand less than 20 kW served by nonaffiliated REPs times the average annual consumption of small commercial customers with peak demand less than 20 kW served by the affiliated electric utility during the calendar year 2000.

(I) The number of customers served by nonaffiliated REPs shall be determined by summing the number of small commercial customers with peak demands less than 20 kW served in the transmission and distribution utility's certificated service area with a designated REP other than the affiliated REP in the registration database maintained by the registration agent.

(II) The average annual consumption shall be calculated by dividing the total kWh consumed by small commercial customers with peak demand of less than 20 kW during the calendar year 2000 by the average number of small commercial customers with peak demand of less than 20 kW during the calendar year 2000. The average number of small commercial customers with peak demand of less than 20 kW shall be calculated by dividing the total number of such customers for each month of 2000 by 12.

(ii) The amount of electric power consumed by small commercial customers with peak demand in excess of 20 kW shall be the actual usage of those customers during the calendar year 2000.

(I) If less than 12 months of consumption history exists for such a customer during the calendar year 2000, the available calendar year 2000 usage history shall be supplemented with the most recent prior history of service at that customer's location for the unavailable months.

(II) For customers with service to a new location, the annual consumption shall be deemed to be equal to the estimated maximum annual demand used by the affiliated transmission and distribution utility in sizing the facilities installed to serve that customer multiplied by the product of 8,760 hours and the average annual load factor for small commercial customers with peak demand greater than 20 kW for the year 2000.

(j) **Prohibition on incentives to switch.** An affiliated REP may not provide an incentive to switch to a nonaffiliated REP, promote any nonaffiliated REP, or exchange customers with any nonaffiliated REP in order to meet the requirements of subsection (f) of this section. Non-affiliated REPs may not provide an incentive to return to the price to beat.

(k) **Disclosure of price to beat rate.** An affiliated retail electric provider shall disclose to customers, the price to beat in accordance with §25.471 (relating to General Provisions of Customer Protection Rules). In addition, if an affiliated REP offers a rate greater than the price to beat, the price to beat rate must be disclosed along with a statement that the customer is eligible for the price to beat. This disclosure must appear on all written authorizations, Internet authorizations, the electricity facts label and Terms of Service document. It must also be disclosed during telephone solicitations before the customer authorizes service.

(l) **Filing requirements.**

(1) On determining that its affiliated retail electric provider has met the requirements of subsection (i) of this section, an electric utility or transmission and distribution utility shall make a filing with the commission attesting under oath to the fact that those requirements have been met and that the restrictions of subsection (h) of this section as well as the true-up in PURA §39.262(e) are no longer applicable.

(2) An electric utility or transmission and distribution utility shall file a progress report with the commission after its affiliated REP has met the requirements of subsection (i) of this section using a 35% threshold target in lieu of a 40% threshold. Such progress reports(s) shall be filed no later than 30 days after the 35% threshold has been met and shall contain the same information required in this subsection.

(3) No later than December 31, 2001, each transmission and distribution utility shall determine the power consumption threshold targets under subsection (i) of this section for residential and small commercial customers within its certificated service area and shall file this information with the commission and shall also make this information publicly available through its Internet website. Each transmission and distribution utility, together with its affiliated REP, shall update the small commercial power consumption

threshold as needed to reflect additional small commercial load that has met the requirements of subsection (h)(3) of this section and therefore is appropriate removed from the calculation of the threshold target. Concurrent with this update, the transmission and distribution utility, together with its affiliated REP, shall provide, for each group of aggregated customers that have been removed from the calculation of the threshold target, the customers' names, electric service identifiers, size of the customers' loads (individually and in the aggregate), and how the customers meet the requirements of subsection (h)(3). Such information may be filed under confidential seal. All certificated REPs shall be deemed to have standing to review such filings.

(4) Any application filed pursuant to this subsection shall contain the following information:

(A) a detailed explanation of how the relevant customer group has met or exceeded the threshold consumption targets in subsection (i) of this section;

(B) calculation of the power consumption threshold target under subsection (i) of this section for the relevant customer group and the date such target was met;

(C) verification of the meeting of the threshold target in the following manner:

(i) for the residential customer class, independent verification from the registration agent verifying the number of customers in the residential customer class within the transmission and distribution utility's certificated service area that are committed to be served by non-affiliated REPs.

(ii) for the small commercial class, an affidavit detailing the number of customers in the small commercial class with peak demand below 20 kW within the transmission and distribution utility's certificated service area committed to be served by non-affiliated REPs and the customers with peak demand in excess of 20 kW with their actual usage calculated in accordance with subsection (i)(2)(B)(ii) within the transmission and distribution utility's certificated service area that are committed to be served by non-affiliated REPs.

(iii) For purposes of this subsection, a residential and small commercial customer has committed to be served by a nonaffiliated retail electric provider if the registration agent has received a switch request for that customer and any mandated cancellation period pursuant to applicable commission rule has expired.

(5) The commission staff shall review all applications filed under this subsection and shall make a recommendation to the commission within ten days after the application is filed to approve or reject the application. If a filing has insufficient information from which the commission can make a determination, the commission may reject the filing without prejudice for refiling the application. The commission shall issue an order approving or rejecting the application within 30 days after the application is filed. An electric utility or transmission and distribution utility filing an application under this subsection shall not

charge rates different from the price to beat until the earlier of 36 months after the date customer choice is introduced or the date such application has been approved by the commission.

This agency hereby certifies that the rule, as adopted, has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.41 relating to Price to Beat is hereby adopted with changes to the text as proposed.

**ISSUED IN AUSTIN, TEXAS ON THE 20th DAY OF MARCH 2001.**

**PUBLIC UTILITY COMMISSION OF TEXAS**

______________________________
**Chairman Pat Wood, III**

______________________________
**Commissioner Judy Walsh**

______________________________
**Commissioner Brett A. Perlman**

## *Hedging with Energy Futures Contracts*

The financial hedging of price risk has several other advantages over using forward physical contracts.

- Financial hedging instruments, such as futures, options and commodity swaps, are competitively priced and often readily available.
- Since a financial hedge is a paper transaction, it doesn't interfere with physical business operations.
  - You retain flexibility on how you buy or sell the physical commodity.
- A financial hedge is flexible and can be reversed at prevailing market prices.

15

## *Hedging with Energy Futures Contracts*

Financial hedging needs to serve a sound business purpose.

- Remember, it's just a way to fix a forward price.
- Inappropriate hedging can actually increase a firm's risk.

16

# BEFORE THE PUBLIC SERVICE COMMISSION

# OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of the Tariffs of Aquila, Inc. d/b/a Aquila Networks –MPS and Aquila Networks-L&P Increasing Electric Rates for the Service Provided to Customers in the Aquila Networks MPS and Aquila Networks-L&P Service Areas. | ) ) ) ) ) ) | **Case No. ER-2007-0004** Tariff No. YE-2007-0001 |

## CONCURRING OPINION OF CHAIRMAN JEFF DAVIS

This commissioner corrects the concurrence filed on May 17, 2007. This concurrence corrects the numbers but does not change the substance of the concurrence.

This commissioner respectfully concurs with the majority decision in all parts; however, there are at least three points raised in this case worthy of further commentary: (1) Skyrocketing fuel prices are driving large rate increases for Aquila customers and, absent some change of circumstances, it is likely Aquila customers will see significant rate increases over the next few years; (2) This report and order marks the first time the Missouri Public Service Commission has implemented a fuel adjustment mechanism pursuant to Section 386.266 enacted in 2005 by the Missouri General Assembly with the passage of Senate Bill 179; and (3) The ex-parte communication from Pirate Capital in this case illustrates that the source of capital can be as important as the attraction of capital itself when determining what's in the public interest.

This opinion, like all other opinions, is based on the facts and circumstances of this particular case as well as preceding cases this body may recognize. Nothing in this opinion should be construed as to any position this commissioner might take in any case, currently pending or in the future.

**1. Rising fuel prices dictated the majority of this rate increase and, absent some change in circumstances, this trend will likely continue.**

Subject to the adjustments set out in paragraphs 5, 10 and 13 of the stipulation, all of the parties agreed to an increase of at least $40.6 million for Aquila's MPS territory and at least $12.7 million for its St. Joseph Light & Power property for a total of roughly $53.3 million. The actual award in this case is approximately $58.7 million. Further, the company is receiving a fuel adjustment mechanism (FAC).

This increase follows a $44.8 million rate increase awarded by this commission for both properties in February 2006. As stated in the majority opinion, fuel and purchased-power expenses make up approximately 46 percent of Aquila's total operating costs. These costs rose 13 percent to 20 percent annually over the three-year period ending June 30, 2006. This pattern of increases is of great concern because subsequent increases in fuel costs will necessitate Aquila seeking additional rate increases of a similar magnitude.

The light at the end of the tunnel – the rate stability so many of Aquila's customers are desperately seeking – appears to be years away. Aquila's fuel and purchased-power expenditures have increased rapidly in recent years. This underscores the perils of being a vertically integrated utility with a significant reliance on natural-gas fired generation and purchased power. The general trend appears to be that both the price of natural gas and the demand for purchased power will continue to increase. Those increased costs will ultimately be reflected in increased rates for Aquila customers.

The goal can and must be rate stability for consumers, even though that goal is challenging and may take years to accomplish. Aquila's fuel and purchased-power costs may well remain upwardly volatile until the company acquires more generation to meet both baseload and peak capacity demand. Aquila is taking steps to add generation capacity by partnering with KCP&L to construct the Iatan II Coal Plant and to construct two new natural gas-fueled electricity-generating turbines in Sedalia, Missouri.

While increasing generation capacity is essential to meeting baseload and peak demands for electricity, it is no panacea for Aquila's customers in terms of rate stability. Assuming the Iatan II coal plant is constructed on schedule in 2010, Aquila will be back in front of this commission seeking another substantive rate increase because the costs of power plant construction cannot be put into rates until the plant is "used and useful." (Chapter 393.135 RSMo, 2000) These costs could be compounded by compliance with future emissions requirements, particularly any federal action on carbon dioxide emissions (CO2).

**2. This decision marks the first time this commission has implemented a fuel adjustment mechanism (FAC) pursuant to Section 386.266 approved by the General Assembly in Senate Bill 179 (2005 legislative session).**

Lately, Aquila's rising fuel and purchased-power costs by themselves are enough to cause rate shock when those costs are eventually passed through to customers in the form of a rate case. Skyrocketing fuel and purchased power prices can compound rate risk for consumers because, when they necessitate a rate case, the company will also seek recovery of their rate case expenses as well as other expenses.

In 2005, the Missouri General Assembly enacted Senate Bill 179 to provide this commission with the option of using a fuel-adjustment mechanism as a tool to establish just and reasonable rates between rate case filings by incorporating market cost changes for prudent, necessary fuel and purchased-power costs.

More than 25 other states can use this method of utility rate regulation. It smoothes the impact of fuel-cost volatility spikes on consumers, minimizes rate shock resulting from the eventual pass-through of fuel and purchased power costs due to regulatory lag and spares both consumers and taxpayers the expense of a rate case when the principal cost driver is the cost of fuel and purchased power.

This commission recognizes the hardship rate volatility can place on all classes of consumers – residential, commercial and industrial. Further, we are all acutely aware of the need to institute safeguards to ensure fuel adjustment clauses do not allow utility service providers to incur fuel costs in an imprudent manner.

That being said, a line-item surcharge allowing a utility to recover its prudently incurred fuel and purchased-power costs is a necessary evil in the case of this particular company. In a time of rapidly rising fuel and purchased-power prices, there is no way a company like Aquila can earn its allowed return on equity by reducing its expenses by tens of millions of dollars in other areas to offset increased fuel and purchased-power costs. In short, fuel and purchased-power increases are dramatically outpacing the ability of the company to absorb these costs. When those expenses already amount to almost half of the company's total expenses, no amount of increased efficiency can offset tens of millions of dollars in new expenses.

The ability to earn an allowed return on equity is important. These earnings attract and sustain investment the company needs to expand generating capacity and maintain essential infrastructure. There is no disputing the Aquila system could use more investment.

Critics of Aquila will argue Aquila is responsible for its own difficulties. There is no doubt Aquila management shares some responsibility in creating this dilemma. Other than PSC staff's assertion that Aquila should have built and kept the Aries plat, no testimony has been offered in this proceeding or any other previous proceeding that said Aquila should have undertaken a plan to construct other electric generation alternatives a decade ago. In fact, the conventional wisdom of the late 90's was that that the price of natural gas would remain relatively stable and no one ever anticipated the price of natural gas peaking at more than $10.00/mmbtu. If those assumptions were correct, natural gas fired generation would have proven to be more cost-competitive with coal-fired generation.

These facts, when combined with the costly and exhaustive permitting process required by the Missouri Department of Natural Resources (DNR) in granting emissions permits, make it highly unlikely Aquila would have ever been able to construct a coal plant under those conditions. Accordingly, it is very difficult to accurately and proportionately balance the culpability of Aquila's management for the challenges the company now faces in containing costs related to providing reliable and affordable utility services to its customers.

All of the proposed FAC mechanisms in this case had some facet that was unappealing. Aquila's proposal to recover 100 percent of its fuel increase costs was technically sound, but failed to ensure prudent and necessary pass-through because the company incurred no risk of financial loss if it failed to prudently manage its fuel costs. The 95 percent pass-through adopted by the majority in this case is reasonable in that it allows the company to recover all or most of its fuel and purchased power costs above $200 million, while encouraging the company to be prudent. For instance, if fuel and purchased power costs increase by $30 million in one year to a level of $230 million total -- a likely scenario based on the testimony presented in this case -- the company will recover $28.5 million of those costs and lose $1.5 million.

A company like Aquila might be able to make up a $1.5 million annual shortfall and, based on judgment and experience, such a shortfall is reasonable under the circumstances. Thus, in my opinion, this approach is most reasonable under the circumstances facing Aquila and the customers it serves.

The other proposals considered by the PSC would have excessively penalized the company for fuel and purchased power costs far beyond its control. This would make it extremely difficult for the company to reinvest in infrastructure and to attract the investment capital necessary to maintain infrastructure and expand generation capacity.

I found the other proposed cost-sharing mechanisms unreasonable for the following reasons:

-an interim energy charge or I.E.C. similar to the one proposed in this case cost Aquila more than $20 million since their last rate case decision in February 2006. Accordingly, I did not feel comfortable adopting the methodology proposed by the PSC staff in this case.

-the 50-50 sharing proposal proposed by several parties of the parties is unfair for a company like Aquila. In scenarios such as that referenced above, Aquila has no means of possibly offsetting a loss of $15 million or more on an annual basis.

-the Wyoming Plan sponsored by AARP has some attractive features similar to the IEC in that it contained a deadband, which would require the utility to absorb costs within a certain range, and encouraged proportionate sharing with no cap. If the market for fuel and purchased power were less volatile, this proposal definitely would merit strong consideration; however, in an era of upward cost volatility, the deadband prohibits the utility from recovering a significant portion of its prudently incurred costs at the outset.

-Although intriguing, an accounting authority order (AAO) would be something this commissioner would gladly consider if this commission had no other alternative. The weakness of the AAO is that it will be thrown into the next rate case. Parties will make all sorts of arguments to disallow those expenses and the company will either agree to take less than they are otherwise entitled in settlement or run the risk of the commission arbitrarily making downward adjustments in other areas because the recovery of the AAO expenses has the potential of being such a large issue.

Absent certainty of fuel cost variances, some aspects of rate setting are like rate design in that they are more art that science. Although the parties are to be commended for coming to an agreement on how the process should work, their extreme positions left this commission in the position of having to try develop a FAC mechanism that would be just and reasonable to all parties.

Aquila should be very mindful that the majority of this commission took a bold step in awarding Aquila a fuel adjustment mechanism. This commission and the General Assembly will be watching. If Aquila fails to adopt a proper hedging strategy, fails to follow its hedging strategy or abuses the discretion given to it by this commission in any other way, this commissioner will not hesitate to modify or reject Aquila's FAC application in a future proceeding.

**3. The ex-parte communication from Pirate Capital in this case illustrates the point that the source of capital is as important as the attraction of capital itself when determining what's in the public's best interest.**

**A. Concerns regarding the attraction of capital:**

Attraction of capital is essential for all utilities, especially those who need to spend large sums of money to enhance reliability, improve infrastructure and add new generation. This is particularly true regarding baseload generation, which is more expensive and takes longer to construct.

Aquila is a vertically integrated utility needing to make significant investments in all three of these areas. This commission has to avoid the temptation of being punitive in rate proceedings to the extent it leaves a company vulnerable to problems caused by undercapitalization and inadequate earnings potential.

Missouri utilities, including Aquila, seem to have no problem attracting investment capital. However, recent events such as the collapse of the Amaranth hedge fund and its effect on the futures market for natural gas, the proposed acquisition of Texas Utilities (TXU) by private equity firms and Pirate Capital's rattling of the saber in the middle of this rate case begs the question of who's going to actually run the company and whether some investors require greater regulatory scrutiny.

Although the issue is not squarely in front of us in this case, the generally accepted principle that "cash is cash" may no longer be true when a group of new, more active investors pushes its way through the boardroom doors, and if the short-term interests of those investors collide with and ultimately prove detrimental to the long-term benefit of ratepayers – the public interest.

For instance, a five-year plan designed to reduce debt and improve Aquila's capital structure could ultimately increase the company's return in a rate case at the expense of delaying improvements necessary to enhance the reliability of the Aquila system. This type of action might be detrimental to the current generation of Aquila ratepayers in terms of reliability and risk further rate increases to the next generation of Aquila customers.

This Commission is likely to view a conscious decision by utility management to purchase power and pass it through a fuel adjustment mechanism, rather than construct appropriate generation resources as detrimental to ratepayers. Neither of these issues is before this commission today, but they are foreseeable, particularly where a company has demonstrated questionable decision-making ability in the past. This commission must be vigilant against conduct that is not in the long-term best interests of the state and its ratepayers.

**B. Concerns regarding Aquila management decisions affecting the company's ability to attract capital:**

The commission staff -- led by Bob Schallenberg, Director of the PSC's Utility Services Division -- and others here at the Commission have consistently taken a long-range view of utility planning – spanning 30 years or longer.[1] These views are most evident in cases where the prudence of constructing new generation assets is an issue. In those cases, the PSC staff has taken positions in favor of Missouri electric utilities owning their own electric generation because it is more reliable to have generation facilities located near the customers being served and cheaper once the costs are depreciated over a period of thirty years or longer. Companies that followed this strategy and built excess generation capacity, like KCP&L and Ameren UE, have used off-system sales of their excess electricity to subsidize costs to their regulated utility customers.

Both utilities and customers have benefited under this regulatory framework. Ameren UE and KCP&L generated earnings for their investors and avoided rate increases for almost two decades, while actually reducing the rates paid by their

---

1 Equally important to note is that, to the best of this commissioner's knowledge, the PSC staff has always opposed acquisition premiums being passed through to utility ratepayers and the Missouri PSC has never approved such a premium.

customers over that same period. This accomplishment is no small feat and provides strong support for the long-term approach espoused by Mr. Schallenberg and the rest of the PSC staff in this regard.

In contrast to Ameren UE and KCP&L, Aquila purchases a substantial portion of the electricity it needs to meet customer demands. Aquila even divested its interest in the Aries plant and then unsuccessfully tried to re-acquire the plant. The evidence in this case shows Aquila's fuel and purchased power expenses have risen rapidly and all relevant information at our disposal indicates that these costs will continue to rise – the only question is how much?

Aquila needs more baseload generation and, according to the PSC staff, at least two more gas-fired turbines. Constructing power plants is expensive and these facilities constitute only a portion of Aquila's capital concerns. Based on the PSC staff's depreciation studies, Aquila's distribution system is one of the oldest in the state and likely in need of further investment. It could be argued that investments should have already been made, but simply weren't made because Aquila did not have the cash flow to make them.

Last year, the Office of Public Counsel (OPC) filed a request seeking a management audit of Aquila in case number EO-2006-0356. The PSC Staff performed a limited audit and Mr. Mills filed a response raising some very valid points on behalf of OPC in response to those findings on October 31, 2006. This commission subsequently issued an order "accepting" the report and directing Aquila to comply with all of the recommendations contained therein on March 13, 2007. Although the order was silent as to the issue, it is noteworthy that KCP&L's proposed acquisition of Aquila was announced in January 2007.[2] Had the proposed acquisition not been announced, it is almost a certainty that Aquila's management would have faced more scrutiny of its management decisions and this commission would be entertaining further suggestions from Mr. Mills' office. Pending the outcome of that case, we still might be considering further steps regarding Aquila management.

Mr. Mills is correct in that there are ample grounds for questioning the prudence of Aquila's management, past and present. These include:

-Management decisions to pursue unregulated business ventures that eventually caused Aquila to hemorrhage money, lose its investment grade status and some would say neglect its customers for years;

-The decision of Aquila to sell its interest in the Aries plant to Calpine and the subsequent mishandling of the zoning, siting and construction of the South Harper generating facility which will be a source of controversy for this commission, the courts and the legislature for years to come.

-A subsequently corrected "accounting error" discovered in a previous rate case that under-funded employee pension benefits;

-Aquila's decisions that led the company to pay $25 million to settle claims with the Commodities Futures Trading Commission (CFTC) and the PSC's subsequent lawsuit against Aquila Inc., Aquila Merchant Services, Inc., and other energy marketers seeking monetary damages for allegations of natural gas price manipulation.

**C. How should this commission resolve lingering allegations of imprudence by Aquila management?**

In fairness to Aquila's current management, I am not sure if different management would have been able to perform better given the same circumstances. Although I might agree with the PSC staff, OPC and other interested parties on a philosophical level, the commission employs a "reasonable person standard" to determine whether the company's decision was reasonable under the circumstances.

---

2 See Case No. EM-2007-0374

Imprudence on the part of a utility is difficult to prove under this standard for two reasons: First, the company is usually able to put forth some evidence its managers were acting prudently under the circumstances; and second, damages are often difficult, if not impossible, to quantify. That being said, when one considers the totality of the circumstances, Mr. Mills is justified in his desire that this commission keep a tight leash on Aquila.

There is no question Aquila's decisions have been detrimental to its ratepayers. That detriment is difficult, if not impossible, to quantify; nor is it feasible to calculate whether or not those decisions should have been dealt with by this commission in previous rate proceedings subsequent to the alleged imprudent behavior actually occurring. There is no clear answer to this question and these issues will continue to haunt Aquila management for years to come regardless of who's in charge.

**Respectfully submitted,**

Jeff Davis
Chairman

Dated at Jefferson City, Missouri,
on this 9th day of July, 2007.