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BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF MISSOURI

DIRECT TESTIMONY

OF

MICHAEL L. BROSCH

ON BEHALF OF

STATE OF MISSOURI

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Q. Please state your name and business address.

A. My name is Michael L. Brosch. My business address is 740 North Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. Are you the same Michael L. Brosch who submitted Direct Testimony in this Case on December 15, 2006 addressing revenue requirements?

A. Yes. My qualifications were described in that previous submission. That earlier testimony addressed revenue requirement issues and certain test year adjustments to rate base and operating income for AmerenUE ("UE" or "Company").

Q. On whose behalf are you appearing in this proceeding?

A. As before, I am appearing on behalf of the State of Missouri ("State").

Q. What is the purpose of your testimony at this time?

A. My testimony explains my evaluation of issues arising from AmerenUE's request for a fuel adjustment clause ("FAC") tariff and procedure. I describe the general ratemaking concerns that are intended to be addressed by automatic adjustments clauses and the types of problems caused by such adjustment devices. I also respond to the Direct Testimony of Company witness Mr. Martin J. Lyons who sponsors the AmerenUE proposed FAC tariff. The specific circumstances of AmerenUE, as well as these general ratemaking concerns, should be considered by the Commission in determining whether an FAC should be approved for the Company. My recommendation is that an FAC not be approved for AmerenUE at this time, based upon the facts and circumstances described herein.

EXECUTIVE SUMMARY

Q. Please summarize your Fuel Adjustment Clause Testimony.

A. My testimony describes how rate tracking tariffs differ from traditional test year regulation of public utilities, explaining how piecemeal ratemaking for selected cost changes is generally undesirable, and why tracking energy costs through an FAC tariff should only be allowed under certain circumstances. Traditional test year regulation is generally preferable to single-issue rate adjustments based upon changes in only selected cost elements because of the need for a "matched" and internally consistent measurement of changing costs and revenues when revising utility rates. Traditional regulation also creates a desirable regulatory lag incentive to management that encourages efficient cost controls, but this incentive is blunted when automatic adjustments clause regulation allows higher costs to be translated directly into higher prices.

Piecemeal rate tracking tariffs, such as the proposed FAC tariff, should only be allowed under exceptional circumstances, for large and volatile elements of utility cost that are beyond management control and that threaten the utility's financial stability if not tracked. This is because such rate tracking shifts the risks of cost increases to utility customers, who are least able to control such costs, while reducing incentives for efficient utility management and adding complexity to customer billings and regulatory processes.

AmerenUE has not demonstrated that its fuel costs are sufficiently large and volatile enough to merit special rate tracking. To the contrary, the Company has sufficiently hedged its exposure to energy price changes through risk management procedures and multi-year fuel supply contracts, such that risks of volatile fuel price changes are modest in relation to overall costs and revenue levels. It must be noted that AmerenUE has a fuel mix that limits its exposure to gas and oil price volatility. Additionally, unacceptable complexity is added to any FAC tariff implementation for AmerenUE because of the Taum Sauk outage, the Electric Energy, Inc. issue and the expiring contract for purchased power from Entergy Arkansas. On balance, the Company has not demonstrated that its proposed FAC is needed or consistent with the public interest when these factors are considered.

TRADITIONAL VERSUS RATE TRACKER REGULATION

Q. What is the purpose of a Fuel Adjustment Clause tariff?

A. A fuel adjustment clause tariff is a regulatory tool that systematically changes utility pricing to "track" changes in defined categories of energy production costs, characterized generally as "fuel" costs. An FAC tariff is designed to periodically change the utility's billings to customers, by isolating and tracking changes in the utility's energy production costs for regular rate adjustments on a piecemeal basis, without regard to how the rest of the utility's costs or overall revenue levels are changing.

Q. Please describe how traditional regulation compares to such rate tracker regulation.

A. In contrast to the piecemeal, single-issue ratemaking that occurs with a tracking tariff such as an FAC, traditional regulation is holistically based upon all elements of the utility's costs and revenues. The overall analysis of all utility costs and revenues is important because it accounts for the fact that each element of the utility revenue requirement tends to vary with the passage of time, with favorable changes (revenue growth or declining costs) tending to offset unfavorable changes (revenue declines or increasing costs).

Energy utilities have traditionally been regulated based upon their overall cost to provide service, including an opportunity to earn a reasonable return on invested capital. The process used to evaluate and measure the cost of service and resulting revenue requirement is the rate case, in which a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates can be undertaken at a common point in time, referred to as a "test period." In Missouri, the test period is usually a recent actual 12-month period of time within which pro forma revenues at present rate levels are compared to pro forma operating expenses and the required return on end-of-period rate base, to determine whether an overall increase or reduction in revenue levels is needed. Indeed, the pending AmerenUE rate case utilizes the twelve month period ending June 31, 2006, with adjustments for known and measurable changes thereafter.

Q. Why is a test period important to the conduct of traditional regulation?

A. It is essential for this synchronized review of both revenue levels and cost levels to occur within a carefully structured and internally consistent test period, because a utility's revenues and its costs tend to both change with the passage of time as customers are added, as inflation and productivity impact cost levels, as capital market conditions change and as sales volumes fluctuate. The dynamic nature of utility costs and revenues does not necessarily imply frequent rate cases. As long as revenues and costs remain in approximate balance, causing the utility's earnings to stay within acceptable proximity to authorized return levels, an electric or gas utility may be able go many years between rate cases.

Another important element of traditional test period regulation is the incentive created for management to control and reduce costs, so as to maximize the opportunity to actually earn at or above the authorized return level between rate case test periods. Regulatory lag creates a balanced incentive for management to control all costs between test years, so as to maximize the opportunity to earn the authorized return.

Yet another beneficial characteristic of traditional test year regulation is the intensive focus upon utility operations and costs within a formal proceeding in which Commission Staff and other interested parties can carefully examine or audit the components making up the revenue requirement. In contrast, piecemeal rate tracking tariff adjustments often receive limited scrutiny or input from regulators and consumer representatives, even though significant customer impacts can result from such tariffs. These mechanisms place an added burden on Commission Staff and intervenors, and ultimately regulatory bodies are likely to give less scrutiny to these costs.

Q. Under traditional test period rate case regulation, what normally happens when a specific utility expense increases between test periods?

A. Increases in specific individual expenses between test periods, if nothing else changes, would directly impact the utility's pre-tax earnings and the achieved rate of return. However, all of the utility's costs and revenues tend to change over time. Customer and revenue growth or reductions in other costs often serve to offset or mitigate isolated cost changes, such that a utility company may be able to avoid rate increases for extended periods of time. For example, AmerenUE has been able to avoid any general rate increase cases for two decades, according to the testimony of Mr. Warner Baxter,[1] even though the Company has had no FAC in place during this time, a clear indication that load and revenue growth, as well as cost savings in other parts of the business have long been adequate to offset fuel price increases that have impacted the Company.

Q. If the continuous changes that impact utility revenues and costs become imbalanced, what can a utility do to ensure reasonable financial results for its investors?

A. Sustained cost increases that are not offset by reductions in other costs or by increases in customer and sales levels may contribute to declines in achieved returns sufficient to justify the filing of a petition to increase rates. Notably, whenever a rate case occurs, all of the elements of revenue requirement are again measured and adjusted, in a balanced overall review that should account for cost increases in some areas being offset by cost savings in other areas. For example, in its pending rate case, AmerenUE is forced to account for its higher customer count and sales volumes and its current capital market conditions and cost of capital, at the same time it has proposed to recognize a larger rate base and increased depreciation expenses. This balanced review of all elements of revenue requirement is a key characteristic of traditional regulation.

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[1] Direct Testimony of Warner Baxter, page 5.

Q. Are there any incentives to promote management cost control and efficiency under traditional regulation?

A. Yes. The "regulatory lag" that occurs between rate case test years serves to promote cost control and efficiency. Once revenues and costs are measured within the rate case test period under traditional regulation and included in the revenue requirement, subsequent changes such as cost reductions or sales margin growth cause improvements in the achieved actual return level, relative to Commission-authorized returns, and are "favorable" from the shareholder perspective. Shareholders are rewarded with higher earnings between test years when management is able to successfully minimize cost increases, maximize productivity gains, or add profitable new customers to the system. Conversely, unfavorable changes between test years, such as cost increases or sales revenue declines, can contribute to earnings below authorized levels. Punishment in the form of reduced earnings occurs when expenses increase or when rate base or cost of capital increases between rate case test periods are not fully offset by revenue gains. In this way, regulatory lag provides a symmetrical incentive for management that can either reward cost containment and the profitable growth in sales or temporarily punish excessive cost increases until the time when a new rate case can be litigated.

Q. Can there be a problem created by regulatory lag under traditional regulation, when large individual cost elements change so rapidly that test year rate cases cannot keep up?

A. Yes. Regulatory lag can contribute to unreasonable ratemaking results if costs change too rapidly between test years. Exceptions to the normal holistic test period review of revenues and costs have been allowed in limited instances by regulators for certain large and volatile cost elements that are predominately beyond the control of utility management and that might produce unacceptable financial outcomes if not allowed special treatment. The most common exception to traditional test period regulation is the widespread utilization of purchased energy adjustment clauses to periodically adjust rates, so as to track changes in the costs of purchased gas for local gas distribution utilities or to track changes in the costs of generation fuel and/or purchased power incurred by electric utilities. Fuel Adjustment Clause (FAC) and Purchased Gas Adjustment (PGA) mechanisms are employed by state regulators when fuel and purchased energy commodity costs are recognized to be:

- Large in relation to the total cost to provide electric service;
- Subject to market forces (rather than management control);
- Volatile and difficult to reasonably quantify in rate cases; and
- Substantial enough to cause potentially significant earnings volatility if not tracked.

Another exception to traditional test period regulation that occurs with some regularity is the concept of deferral accounting, which is sometimes referred to as an accounting authority order. For designated transactions or types of costs, the utility may be allowed to deviate from the accounting otherwise required under Generally Accepted Accounting Principles (GAAP) or the Federal Energy Regulatory Commission (FERC) accounting principles set forth in the Uniform System of Accounts (USOA). Examples of accounting deferral orders might include extraordinary storm recovery costs or deferral of costs associated with merger transaction and transition costs, in an effort to mitigate the financial impact of extraordinary events or to better match cost recognition to the periods thought to benefit from a merger of utility entities.

Q. What general problems are created by the use of rate trackers and accounting deferrals in place of traditional holistic regulation?

A. The primary problem associated with use of these regulatory tools is the potentially serious distortion of the "matching" that is desirable in a rate case test year. This is often referred to as the "matching principle" in ratemaking. It recognizes the importance of matching all revenues and costs (expenses, rate base, rate of return) at a consistent period of time to determine needed changes in utility pricing. Rate tracker tariffs, such as AmerenUE's proposed FAC, cause what is referred to as "piecemeal" ratemaking, where prices to customers are changed for only "pieces" of the overall revenue requirement, without regard to whether changes to other non-fuel expenses, rate base, capital cost rates or increasing sales levels would serve to mitigate the fuel cost changes if also considered.

As I mentioned earlier in this testimony, all elements of the revenue requirement calculation are dynamic through time and changes that are favorable tend to offset other changes that are unfavorable. For example, adding customers and the related revenue growth can help "pay for" increases in operating expenses, while growth in the depreciation reserve tends to offset much of the construction activity that adds new Plant in Service. If a party is allowed to select certain items for special treatment with a rate tracker or through deferral accounting, one can reasonably expect that the selected items will be "cherry picked" by that advocate so as to influence the regulatory process to the sole advantage of that party.

Q. Do piecemeal cost tracking tariffs such as FAC clauses create other problems, beyond the damage done to test year matching?

A. Yes. Other concerns with these rate tracker exceptions to a traditional, balanced test year analysis of the revenue requirement include:

- Reduction of management incentives (by eliminating regulatory lag);
- Shifting of cost responsibility and risk to customers who are least able to influence cost levels or sales levels;
- Increases in tariff and bill complexity that may be difficult to explain to customers or that may complicate customers' ability to control their costs;
- Administrative complexity and costs associated with audit verification, and administration of complex accounting entries, cost allocations and/or tariff calculations, often on an accelerated procedural schedule; and
- Potential for inadequate regulatory oversight and auditing of tariff application.

With these concerns in mind, I believe that exceptions to normal test year ratemaking using rate trackers and/or deferral accounting should only be allowed when extraordinary circumstances exist that preclude the setting of just and reasonable rates through traditional, balanced test year ratemaking procedures.

Q. Please explain what you mean by your reference to an FAC causing a reduction of management incentives by eliminating regulatory lag.

A. As noted previously, under traditional regulation, utility management is rewarded for efforts to control costs and penalized when costs are not effectively controlled between rate cases, by virtue of regulatory lag in the timing of traditional rate cases. This is a generally desirable phenomena that mimics market incentives that firms face outside of cost-based regulation – if costs increase beyond the levels recoverable in established prices, rates of achieved return will suffer and if costs decline, earnings will grow. Unfortunately, upon implementation of a fuel adjustment clause, any incentive to control FAC-recoverable energy costs is virtually eliminated. Upon implementation of an FAC tracker, rational management behavior would shift attention that is now given to the control of energy costs to other more important areas of the business, because there would no longer be any earnings benefit from efforts and costs focused upon minimizing fuel and purchased energy costs. The FAC passes any energy cost savings or any energy cost increases through to customers, eliminating any incentive to management to reduce such FAC-recoverable costs, particularly if incremental risks or costs are involved in achieving such savings.

Q. Does AmerenUE currently incur significant capital and O&M expenses in an effort to maximize the availability and efficiency of its generating units, so as to minimize fuel and purchased power expenses?

A. Yes.[2] The utility business is capital intensive and generating facilities require substantial ongoing capital investment, as well maintenance resources committed to optimizing generating unit availability and heat rates. Under traditional regulation, balanced incentives exist for management to optimize power plant investment and maintenance costs because spending on such efforts are treated exactly the same way by regulators as

[2] See for example, the Direct Testimony of AmerenUE witnesses Mr. Charles D. Naslund and Mark C. Birk regarding nuclear production performance and non-nuclear production performance measures historically taken by the Company to improve availability and efficiency under traditional regulation.

the fuel and purchased energy cost benefits resulting from such actions – all costs and benefits are considered together within the test year.

Q. Has AmerenUE management acknowledged the significance of an FAC arrangement (or absence of an FAC) upon its incentive to operate efficiently?

A. Yes. In its 1998 Annual Report to shareholders, the Chairman's letter explained how Ameren continues to seek opportunities to maximize generating assets and increase operational efficiency. Of particular interest is the following statement made by the Company's then President and Chief Executive Officer Charles W. Mueller:

> We are also focused on lowering fuel costs. [I]n 1998 in Illinois, we chose to eliminate the fuel adjustment clauses, which called for offering credits if certain fuel costs dropped or increasing customers bills if they rose. That decision, coupled with the fact that we have operated for several years without a fuel adjustment in Missouri, has given us additional incentive to continue to manage our fuel costs effectively.

I have included a complete copy of the Chairman's Letter in that year as Schedule MLB-6 attached to my testimony.

Q. How does implementation of an FAC disturb the existing incentives for efficient management of production resources?

A. Ameren's CEO spoke in 1999 about how the absence of an FAC provides incentives to manage fuel costs effectively. Whenever a fuel adjustment clause is implemented that provides preferential single-issue accelerated rate recognition of fuel cost changes (or purchased energy changes), relative to production maintenance expenses or capital spending, there is no longer a level playing field for management. Utility earnings with an FAC in place can be maximized by reducing production department efficiency spending, creating non-FAC cost savings between rate cases at the same time any corresponding FAC-recoverable fuel and purchased energy cost increases (caused by deteriorating generating unit availability and/or heat rates) are recovered through FAC rate adjustments. Entirely rational management behavior with an FAC in place would be to subtly reduce spending on production maintenance labor and contractor charges and de-emphasize capital projects aimed at improved generating unit availability or heat rates, because any corresponding changes in energy costs simply flow through to customers. Management should also be less interested in staffing and spending on ambitious fuel procurement and fuel contract administration efforts if any benefits from spending in this area simply flow through the FAC to benefit customers. An input mix bias is created by FAC regulation, where some types of utility costs (FAC-recoverable energy costs) are treated differently than other types of costs.

Q. Mr. Lyons notes in his Direct Testimony that only "prudently incurred" fuel costs can be recovered under FAC clauses implemented pursuant to SB 179.[3] Does the risk of a regulatory prudence disallowance replace the loss of regulatory lag incentives that exist under traditional regulation?

A. Not really. After implementation of an FAC, there is only a modest risk of regulatory prudence disallowance if management negligence is observed and proven to the satisfaction of the Commission. In my experience, there have rarely been regulatory disallowances of energy cost increases due to findings of management imprudence. In contrast, the regulatory lag incentive under traditional regulation is ever present and is not dependent upon complex auditing and litigation.

[3] Direct Testimony of Martin J. Lyons, page 6.

Q. Does an FAC of the type proposed by AmerenUE change the relationship between the utility and its customers?

A. Yes. A fuel adjustment clause passes along changes in fuel and purchased energy costs to customers between rate case test years. This pass-through of cost responsibility shifts all of the risk of fuel and purchased energy cost changes from the utility to its customers who are least able to influence such cost levels. Unless regulators insist upon a corresponding adjustment to the utility's allowed rate of return to fully recognize the shifting of costs and risks from shareholders to ratepayers, there is no benefit to ratepayers from an FAC.

Q. Has the Company reduced its recommended return on equity to correspond with the proposal to shift the risks of fuel and purchased energy cost changes to its ratepayers?

A. Not explicitly. According to the Direct Testimony of AmerenUE witness Ms. McShane, at page 9, the Company's "...estimate of the fair return is premised on AmerenUE's ability to fully recover its fuel costs, similar to the typical utility in my comparable sample, which has a fuel adjustment clause. In the absence of a means to recover the anticipated increases in fuel costs, the cost of capital for Ameren would be higher." Of course, it is entirely possible for an electric utility to "fully recover its fuel costs" through base rates without an FAC, as AmerenUE and other Missouri utilities have managed to do for many years.

Q. How else would implementation of an FAC impact AmerenUE customers and the Commission Staff?

A. An FAC process introduces added tariff and bill complexity that may be difficult to explain to customers. More frequent price changes associated with an FAC also tend to complicate customers' ability to control their energy costs. Unlike the present environment, where customers pay a constant rate for the electricity they use and can reasonably predict what they will pay at a given level of usage, an FAC tariff introduces variable pricing and less predictable costs to consumers.

From the perspective of the regulatory agency and its staff, an FAC adds to administrative complexity and costs associated with audit verification, and administration of complex accounting entries, cost allocations and related tariff calculations. Mr. Lyon's Direct Testimony refers to "extensive minimum filing requirements" in connection with the FAC and to "exhaustive monthly surveillance data during the period the FAC is in effect" as well as to "true-up proceedings and prudency reviews". While his concern is likely focused upon the Company's burden to produce such documentation, the Commission should also be mindful of the corresponding burden upon its staff and all concerned customer representatives who must review and analyze such data to effectively monitor future FAC rate increases.

Q. Under what circumstances should regulators consider adoption of tracking tariffs and/or regulatory deferral accounting for specific changes that occur between rate case test years, in spite of the concerns you have noted that are caused by such piecemeal single-issue ratemaking?

A. Because of the concerns I have described, rate trackers and cost deferrals should be approved <u>only</u> in instances where compelling circumstances justify departure from traditional test period review of all costs and revenues within formal rate case proceedings in which the overall revenue requirement can be audited and considered in a balanced and synchronized manner. Costs or revenue changes to be deferred or rate tracked on a piecemeal basis should generally have all of the following attributes to merit such exceptional and preferential rate recovery treatment:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases.
2. Beyond the control of management, where utility management has little influence over experienced revenue or cost levels.
3. Volatile in amount, causing significant swings in income and cash flows if not tracked.
4. Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews.
5. Balanced and not distortive of test period relationships – reflective of factors that mitigate impacts in a manner that preserves test year matching principles.

In the testimony that follows, I will apply these general criteria to the FAC tariff being advocated by AmerenUE, so as to illustrate why the Company's proposed FAC should be rejected at this time.

Q. In your opinion, has AmerenUE justified its proposed new FAC tariff by making a showing that exceptional piecemeal ratemaking is needed for its fuel and purchased power expenses in relation to the criteria that you describe?

A. No. It appears that AmerenUE desires implementation of an FAC tariff because the Company's fuel costs have been increasing and are expected to continue to increase.[4] The expectation that an isolated cost category, such as fuel expense, will increase in the future is not sufficient justification for singling out that cost category for piecemeal rate tracking. Clearly, shareholders would be advantaged if these expectations materialize and if a new FAC tariff is implemented to translate cost increases into piecemeal future rate increases. However, I would encourage the Commission to exercise its discretion when considering departures from traditional regulation by allowing piecemeal rate tracking tariffs only when merited by a showing of extraordinary circumstances under which continued traditional ratemaking cannot be expected to produce just and reasonable future rates.

THE AMERENUE PROPOSED FAC

Q. Please describe the Company's proposed FAC tariff.

A. The Company has proposed a very inclusive FAC approach, under which most costs recorded in FERC Account Nos. 501 (fuel), 536 (water for power), 547 (gas fuel), 518 (nuclear fuel), and Accounts 555, 565 and 575 (purchased power, transmission and market administration) would be tracked for FAC recovery. A base level of these costs would be established in the pending rate case, which AmerenUE has quantified at 1.341 cents per kWh prior to rate case true-up.[5] Future variations from this base rate recovery level of energy costs would be deferred during rolling 3-month accumulation periods, for

[4] See Direct Testimony of Messrs. Warner Baxter, pages 8-10, 21, 38, Robert K. Neff at pages 2-7, 40-41 and Martin J. Lyons Jr. at pages 4 and 5.

[5] Id, page 7.

translation into FAC rate changes to be implemented during a recovery period commencing 3-months after conclusion of each accumulation period.[6]

The proposed tariff is captioned "Rider A" and is set forth in Mr. Lyon's Schedule MJL-1-1. The tariff contains an "FPA DETERMINATION" formula with defined terms that summarize how the proposed FAC process would function. This proposed formula also includes a factor "SMS" to allow for rate tracking of what Mr. Lyon's characterizes as "...to be used to flow through a share of off-system sales margins to customers, if applicable. The Company's primary proposal for addressing off-system sales margins in this case is to include a fixed amount of off-system sales margins (based upon a normalized level of off-system sales margins for the test year) in the revenue requirement used to calculate the Company's base rates."[7]

Q. If we focus upon the test year fuel and purchased power expenses making up the 1.341 cents per kWh proposed by AmerenUE for base rate recovery, what is the makeup of those expenses?

A. The vast majority (about 83%) of the Company's normalized test year energy costs are associated with its coal-fired generation and its nuclear generation, as indicated in the following table:

Base Rate FAC Costs by Type	$ million	%
Coal	409	76%
Nuclear	39	7%
Gas	14	3%
Oil	2	0%
Purchased Power/Transmission	75	14%
Total Energy Cost in Base Rates	539	100%

Source: AmerenUE response AG/UTI-232

6 Direct Testimony of Martin J. Lyons, page 8.
7 Id, page 8.

This mix of AmerenUE energy inputs is quite significant in considering how modestly exposed the Company is to fluctuating market prices for commodity fuel supplies, as explained in greater detail in the next section of this testimony.

Q. According to AmerenUE witness Mr. Lyons' testimony, "AmerenUE's fuel, fuel-related transportation and purchased power costs are large and volatile components of its cost of service. Moreover, these costs fluctuate based on changes in national and international market conditions, and as a result they are in large part beyond AmerenUE's ability to control." Are these reasonable criteria to support rate tracking FAC treatment of such costs?

A. Generally, very large and volatile utility costs that are beyond the control of management and that are substantial enough to cause potential earnings volatility, if not tracked, are eligible for consideration for piecemeal rate tracking treatment. However, AmerenUE's fuel and fuel-related transportation and purchased power costs are relatively less volatile and more controllable by management than is true for other utilities, as more fully explained in the next section of my testimony. For this utility, the problems arising from piecemeal single-issue rate adjustments using an FAC tracker outweigh the apparent need for such ratemaking. Therefore, traditional regulation of AmerenUE energy costs can be expected to maintain a more equitable balance between ratepayers' and shareholders' interests and the Company's FAC proposal should be rejected.

COMPANY-SPECIFIC CONSIDERATIONS

Q. How does AmerenUE acquire the majority of the energy that is sold to its customers?

A. As noted in the table on page 18, more than three fourths of UE energy costs (about 76 percent) arise from AmerenUE's coal-fired baseload generation. AmerenUE is less exposed to volatile gas and oil fuel prices than other utilities in the Midwest because of its heavy utilization of coal-fired baseload generation. According to AmerenUE witness Mr. Robert K. Neff, "AmerenUE will generate 79% of its electricity from coal-fired power plants in the test year....Ninety-six percent of the coal used in these plants originates in the Powder River Basin." The Company's coal intensive fuel mix is also confirmed by AmerenUE witness Mr. Mark C. Birk who notes at page 16 of his Direct Testimony, "Even with the addition of these CTGs, a high percentage of the energy produced by AmerenUE will continue to be produced from AmerenUE's baseload generating units. On average, it is expected that AmerenUE's CTG fleet will run only a small percentage of the time over the next few years."

Q. Does AmerenUE purchase most of its coal under term contracts with fixed prices?

A. The Company employs a ** [redacted], ** by pooling PRB coal requirements and purchasing ** [redacted]. **[8] As part of this process, AmerenUE has adopted ** [redacted], ** which Mr. Neff explains at page 16, stating, ** "[redacted]

[8] Direct Testimony of AmerenUE witness Mr. Robert K. Neff, pages 11-17.

[redacted] **

Q. Will latest known current prices paid by AmerenUE for coal be included as part of the rate case true-up procedure in the pending rate case?

A. Yes. Contract coal prices for the test year are to be trued-up based upon actual pool PRB and Illinois coal delivered prices as of January 2007. Through this true-up process, all historical increases in coal and freight costs sustained by AmerenUE through January 2007 would be fully included within the revenue requirement. This is significant because the historical delivered price increases per ton that are displayed by Mr. Neff in his Table 2: Summary of total Coal and Transportation Costs at page 38 of his testimony will be completely captured by the traditional ratemaking process, making only future price changes relevant in determining AmerenUE's need for an FAC tariff for its changes in its coal fuel costs.

Q. Have PRB coal prices at the mine stabilized recently, after the large run-up in prices associated with the supply disruptions that occurred in 2005?

A. Yes. Attached to my testimony as Schedule MLB-5 is a Coal News and Markets report dated December 20, 2006 issued by the United States Energy Information Administration ("EIA") that illustrates recent cost trends for coal supplies, indicating in a table on page 2 the relative stability of PRB spot coal prices at around $10 per ton in the past few weeks, after a period of steep price increases throughout 2005. This information confirms data presented by Mr. Neff indicating significant historical price increases at the mine for PRB coal, but does not support a conclusion that future prices will necessarily trend upward. In fact, the EIA reports at page 2 that:

> The slackened spot markets are now quiescent. A number of factors contributed to the present lull: concerted efforts that started this past spring to rebuild depleted coal consumer stockpiles with increased deliveries; the opening of shuttered and new mines following the prolonged high coal prices from mid-2004 through early 2006; a relatively mild summer in the service areas of most coal-burning electricity providers; and a mild autumn in most of the eastern United States. Coal stocks in the electric power sector equated to at 44 days supply (125.6MMst) as of September. Coal-fired electric power generators were in a better position than in September in either of the previous two years; the most recent time that end-of-September coal stocks were as high as 44 days' supply was in 2003.

It is reasonably expected that the true-up of AmerenUE fuel prices to replace estimated coal costs with actual costs of January 2007 will be a downward adjustment because of the softening of coal market prices that is noted in the EIA report.[9]

Q. In addition to the price of coal at the mine, is rail freight a significant element of the delivered cost of coal burned by AmerenUE in its base-load generating stations?

A. Yes. Most of the coal burned by AmerenUE is PRB fuel for which 2007 freight costs ** [redacted] **. Mr. Neff notes in his testimony that AmerenUE faces ** [redacted] **, as summarized in the table below:

[9] This adjustment is anticipated by preliminary updated information explained in my earlier Direct Testimony at pages 16-17 regarding State Adjustment C-3 (at line 1).

**

PRB Freight Pricing	2006	1/1/2007
[redacted]	[redacted]	[redacted]

**

The revised rail freight amounts shown to be effective 1/1/2007 for the transportation of PRB coal will also be fully considered in the true-up of fuel expenses in setting base rates, at the same time coal prices at the mine are updated.

Q. After these new freight prices take effect and are recognized in setting the Company's base rates, are future large freight increases anticipated?

A. No. AmerenUE has limited its exposure to coal freight price increases by entering into ** [redacted] **[10]

Q. At page 38 of his Direct Testimony, Mr. Neff states, "AmerenUE also expects its delivered coal prices to increase significantly in 2008 and 2009. This continues a recent trend, particularly over the last two years when coal prices have increased dramatically." What is the magnitude of expected cost increases to AmerenUE in these years?

10 Direct Testimony of Robert K. Neff, page 25, line 9. Additional details of freight contract terms are set forth in AmerenUE's highly confidential response to Data Request No. MPSC 326.

A. With respect to the delivered price of PRB coal inclusive of freight costs, AmerenUE faces a limited known cost increase in 2008 over 2007 prices associated with freight rates, as noted by Mr. Neff at page 41:

> For the year 2008, AmerenUE will ship approximately 23.3 million tons of coal. **[redacted]** of the PRB coal transportation needed for the projected 22.7 million tons of PRB shipments is currently hedged under contract at an average coal freight rate of **[redacted]** per ton.

This anticipated 2008 average freight price is ** [redacted] ** percent higher than the ** [redacted] ** price estimated by AmerenUE for PRB coal freight in 2007. Thus, AmerenUE faces known PRB coal cost increases of approximately ** [redacted] ** per ton on the 22.7 million tons of projected PRB coal to be burned in 2008, which amounts to an annual expense impact of ** [redacted] ** million. As noted previously in this testimony, much of AmerenUE's PRB coal cost that is additive to these known freight rates has been hedged with multi-year contracts and market prices for PRB coal have recently softened, as shown in Schedule MLB-5.

Q. Is this estimated delivered coal fuel expense increase in 2008 large enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases?

A. No. This anticipated expense increase associated with the largest element of AmerenUE fuel expense, its delivered cost of PRB coal, represents less than ** [redacted] ** percent of annual Missouri retail revenues and less than ** [redacted] ** percent of test year operating income.[11] The vast majority of AmerenUE generation uses PRB coal as its fuel supply, for which the Company anticipates known modest cost increases under mostly fixed

11 Annual Missouri revenues at present rates of $2,501 million and pretax operating income of $620 million are set forth at column D, lines 1 and 16 of State Accounting Schedule C.

contract prices for coal and freight, subject to only limited fluctuations in price for quality variations and for price fluctuations for diesel fuel burned by the railroads.

Q. The next second largest element of the Company's energy supply mix is the cost of purchased power and transmission expenses, which represent about 14 percent of total test year megawatthours. Is AmerenUE exposed to significant known cost increases or price volatility with regard to purchased power in the near future?

A. No. About ** [redacted] ** million of this expense category relate to MISO charges for transmission line losses, which should remain relatively stable in the future.[12] There is no reason for these energy loss costs to vary for the existing transmission network. Most of the remaining purchased energy cost in the category for the test year was purchased under a cost-based firm power supply contract with Entergy Arkansas, with a term that expires in ** [redacted] **[13] Energy purchased by AmerenUE under this contract during the test year was priced at only ** [redacted] ** per MWH.[14] When this contract expires after ** [redacted] **, the Company will be exposed to market pricing for replacement power, but considerable savings will be realized through avoidance of capacity payments to Entergy Arkansas in the amount of approximately ** [redacted] ** million annually.[15]

In addition to the MISO charges and purchased power from Entergy, the Company makes hourly purchases of energy to serve its load at market prices. The hourly purchases at market prices and the replacement energy AmerenUE will require

[12] Ameren response to Data Request No. AG/UTI-202 and confidential workpaper GSW-WP-E1163.

[13] AmerenUE response to Data Request No. STF 147 ** [redacted] **

[14] AmerenUE confidential response to Data Request No. MPSC 140 indicates contract purchase energy costs of ** [redacted] ** per MWH. Only the energy component of these costs would be FAC recoverable under the AmerenUE tariff proposal.

[15] Ameren confidential workpaper GSW-WP-E1163.

upon expiration of the Entergy purchase arrangement create some exposure to market price volatility. However, it should be noted that the Company is a net seller of energy, with annual normalized off-system sales margins estimated at $183 million by the Company,[16] an amount which far exceeds the cost of purchased power. If the market price of energy increases in the future, AmerenUE stands to profit from higher sales and margins, that should mitigate and may fully offset any exposure the Company may have to higher prices for energy that it must purchase.

Q. Is it fair to attribute much of any market price risk that AmerenUE faces through utilization of purchased power at market prices to the Company's failure to retain its entitlement to the Joppa coal-fired generation that was addressed in your earlier revenue requirement Direct Testimony?

A. Yes. If Ameren had not allowed the purchase by UE of 400MW of capacity and energy from EE Inc. to expire on December 31, 2005, an even higher percentage of the total energy to serve AmerenUE load would continue to be sourced from low-cost, coal-fired purchased capacity on a going forward basis.[17]

Q. Will the Company's proposed FAC improperly reward the Company upon expiration of the Entergy Arkansas purchased power arrangement?

A. When the Entergy Arkansas transaction expires, the Company will begin to realize capacity charge savings of ** [redacted] ** million per year, even though this expense is

[16] Supplemental Direct Testimony of Shawn Schukar, page 2. Much higher off-system sales margins are estimated by MPSC Staff witness Mr. Rahrer and by the State in preliminary estimates contained in State Joint Accounting Schedule C-2.

[17] See Direct Testimony of Michael L. Brosch filed on December 15, 2006, at pages 18-29.

included in the Company's base rate revenue requirement.[18] Then, if AmerenUE purchases replacement energy for the expiring Entergy contract at hourly market prices, with no explicit new demand charges, the capacity charge savings will be pocketed for shareholders at the same time any increased purchased energy costs are rolled into FAC rate increases for consumers. This is an example of complexity and inequity that can arise upon implementation of piecemeal rate tracking tariffs like the Company's proposed FAC.

Q. Turning next to nuclear fuel expenses for Callaway, which represents about 7 percent of overall energy costs in the test year, how volatile have such costs been historically?

A. Nuclear fuel prices for Callaway station have been very stable and are expected to remain stable. According to AmerenUE's Supplemental Response to Data Request No. MPSC 61, Callaway nuclear fuel costs include three components: fuel, spent fuel and decommissioning and dismantling charges. The spent fuel charges are fixed at $.936/mwh and decommissioning and dismantling are fixed at $1,593,742 per year. Thus, the remaining variable portion of nuclear fuel expense is subject to change generally after each refueling outage for Callaway, when new fuel assemblies are inserted into the reactor. The next scheduled outage in the spring of 2007 and the costs of fuel expected after that refueling outage are already largely reflected in the Company's test year fuel run.[19]

[18] Ameren Confidential workpaper GSW WP-E1163.
[19] AmerenUE responses to Data Request Nos. STF-61 and STF-140.

Q. There has been widespread concern in the utility industry regarding the volatility surrounding prices of fuel oil and natural gas used as fuel by electric utilities. How much exposure does AmerenUE have to this fuel resource?

A. Very little. This is the primary issue that differentiates AmerenUE from other utilities that may be able to justify piecemeal fuel cost rate adjustments through use of FAC tariffs. This utility relies upon its gas and oil fired combustion turbine peaking units for less than ** [redacted] ** percent of annual generation.[20] At test year estimated fuel price levels, gas and oil fuel represent only about three percent of total energy costs.[21] Thus, AmerenUE has very slight exposure to any future volatility in gas and oil prices.

Q. You have described AmerenUE's generation fuel mix, which is heavily weighted toward coal and nuclear generation. Do you believe that the Company's exposure to future fuel price fluctuations represent a potentially material impact upon revenue requirements and the financial performance of the business between rate cases?

A. No. The potential magnitude and timing of future fuel price changes, given the Company's largely coal and nuclear fuel mix and its proven ability to stabilize costs with long-term contracts and other hedging devices, do not represent a significant financial exposure in the normal intervals required between rate cases. Because of its fuel and freight cost hedging procedures and existing contract position, AmerenUE should be able to sufficiently anticipate fuel price changes that do occur in time to commence traditional rate case proceedings when needed to ensure just and reasonable rates reflective of overall costs of service (including energy costs).

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[20] Workpapers of AmerenUE witness Mr. Finnell, "FBREPORT_PSC05_Sep8.xls"
[21] AmerenUE response to Data Request No. AG/UTI-202.

Additionally, the continual ongoing load growth in the Missouri service territory served by the Company can be expected to yield additional margin revenues that will be available to help pay for any gradual future increases in fuel expense that may occur.

Q. Are AmerenUE fuel and purchased power costs beyond the control of management, where utility management has little influence over experienced cost levels?

A. No. There is considerable evidence sponsored by Company witnesses indicating steps taken by AmerenUE to stabilize and control its incurred energy costs. The fact that the Company has not required a Missouri rate case in many years, even though no FAC has existed historically, is an indication of how fuel cost increases that have been experienced must have been offset by revenue growth and/or cost reductions achieved in other parts of the business. Any volatility in energy costs historically has not resulted in significant swings in income and cash flows that forced the Company to seek rate relief.

ADMINISTRATIVE COMPLEXITY CONCERNS

Q. Do you expect the FAC that AmerenUE has proposed will prove to be simple to administer, readily audited and easily verified through expedited regulatory reviews?

A. No. Comprehensive monthly financial and operational data is required to be filed under 4 CSR 240-3.161(5) that must be reviewed, analyzed, and/or audited by Staff and other concerned parties to monitor AmerenUE reported results, if an FAC tariff is approved for the Company. Surveillance monitoring reports are also required under 4

CSR 240-3.161(6) that become much more important for any utility with an FAC, because they enable the Staff to track whether the piecemeal rate changes pursuant to the FAC are contributing to excessive earnings. In addition, 4 CSR 240-3.161(7) specifies additional detailed reporting and rate change calculations to coincide with each filing made by AmerenUE to adjust its FAC rate. Under the Company's proposal, these filings would occur quarterly and the accuracy of all calculations, as well as the prudence of all underlying transactions, would need to be addressed by Staff pursuant to 4 CSR 240-20.090(4) in a "recommendation regarding its examination and analysis to the commission not later than thirty (30) days after the electric utility files its tariff schedule to adjust its FAC rates."

Q. Does the approval of an FAC tariff for AmerenUE also add regulatory complexity by requiring the conduct of periodic prudence audits of all energy costs subject to the FAC?

A. Yes. Prudence reviews are required no less frequently that at eighteen month intervals, pursuant to 4 CSR 240-20.090(7). More frequent general rate cases may also result from implementing an FAC, because such filings are required within not more than four years of FAC approval under the provisions of 4 CSR 240-20.090(6).

Q. Are there additional complexities caused by the Taum Sauk outage that further complicate implementation and administration of any fuel adjustment clause for AmerenUE at this time?

A. Yes. As noted in my prior revenue requirement Direct Testimony, any future FAC rate adjustments that are based upon changes in per book actual fuel and purchased power costs incurred by the Company will be impacted by the higher costs incurred because of the Taum Sauk outage. This could force ratepayers to pay for the higher incurred fuel costs and purchased power costs caused by the Taum Sauk incident. In its response to Data Request AG/UTI-83, the Company stated that test year estimated fuel expense and purchased power expense would be $6.4 million higher if Taum Sauk were modeled as unavailable for the entire year. There is also a negative impact upon realized off-system sales margins caused by the Taum Sauk outage, which AmerenUE estimates to be about $15.0 million annually in the same Data Request response. The Commission's fuel adjustment rules preclude recovery of increased costs resulting from negligent or wrongful acts or omissions by the utility.[22] Therefore, any FAC, approved for AmerenUE, would require careful monitoring and ongoing special studies to adjust recorded costs to ensure that ratepayers are not charged for Taum Sauk outage effects.

Q. Is future administration of the proposed FAC tariff for AmerenUE also potentially complicated by the Company's handling of the EE Inc. purchased power contract that was allowed to expire?

A. Yes. Unless the Commission ultimately agrees with AmerenUE's proposal to retain the economic benefits of the Joppa station for the sole benefit of shareholders, over the objections of Staff, the State and other concerned intervenors, the Company's future per books fuel expenses would be much higher than if the purchase arrangement had

[22] 4 CSR 240-20.090 (1) Definitions states that "Fuel and purchased power costs means prudently incurred and used fuel and purchased power costs, including transportation costs. Prudently incurred costs do not include any increased costs resulting form negligent or wrongful acts or omissions by the utility."

continued. Depending upon the resolution of this issue, considerable complexity may be added to any FAC administration procedures if reported actual energy costs require a second special study and a related adjustment prior to calculating FAC rate adjustments.

OFF-SYSTEM SALES TRACKING

Q. In your prefiled revenue requirement Direct Testimony, you indicated that AmerenUE off-system sales should be subject to regulatory tracking and adjustment, either as part of the Company's fuel adjustment clause tariff that is sponsored by Mr. Lyons, or through a separate deferred accounting tracking mechanism if the Commission does not approve an FAC for the Company.[23] Why do you believe that AmerenUE off-system sales margins merit special rate tracking if the Company's overall energy costs do not?

A. As I noted in my revenue requirement Direct Testimony, there is no historical benchmark for evaluation of off-system sales margins that may recur in the future, because of the many fundamental changes being made to the Company's power supply resources, including termination of the Joint Dispatch Agreement, expiration of the EE Inc. contract, startup of the MISO Day 2 energy markets in 2005 and the addition of substantial new CT generating capacity. There is clearly a wide range of opinions regarding the normal ongoing level of off-system sales margins for the test year.[24] The Company's witness acknowledged the significant uncertainties involved in estimating off-system sales margins and the risk to either customers or shareholders if this amount is determined

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[23] Direct Testimony of Michael L. Brosch, page 13.

[24] AmerenUE witness Mr. Schukar advocates inclusion of $183 million, but a much lower base amount of $120 million if tracking and sharing is approved (Supplemental and Direct Testimony pages 2 and 21, respectively) while my Direct Testimony recommends a $41 million increase to the Company's $183 million amount (State Schedule C-2) and Staff recommends in excess of $360 million in off-system sales margins for the test year (See Staff Adj. S-5.1) increases Interchange sales revenues to $543 million, while fuel costs to support interchanges sales is $178 million (see Staff workpapers).

inaccurately. These facts support a conclusion that off-system sales are much more difficult to accurately quantify for inclusion in base rates than the Company's broader overall energy costs.

Q. How should the separate deferred accounting tracking mechanism for off-system sales margins that you recommend be implemented if the Commission does not approve the AmerenUE FAC tariff and the SMS factor for off-system sales tracking therein?

A. Commencing on the effective date of the Commission's rate case order, AmerenUE should compare its actual realized monthly off-system sales margins in the Missouri retail jurisdiction to the dollar amount ordered for inclusion in the rate case by the Commission. The variance in these two values, on a monthly basis, should be accumulated within a regulatory asset/liability account for consideration in the Company's next Missouri rate case, along with interest on the balance at a rate consistent with the utility's cost of short term borrowed funds.

Q. Does this conclude your direct testimony regarding fuel adjustment clause matters?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))	Case No. ER-2007-0002

AFFIDAVIT OF MICHAEL L. BROSCH

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Michael L. Brosch, being of lawful age, on his oath states: that he has participated in the preparation of the foregoing Direct Testimony in question and answer form to be presented in the above case; that the answers in said Direct Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Michael L. Brosch

Michael L. Brosch

Subscribed and sworn to before me this 28 day of December, 2006.

Lori M. Rice

Notary

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

LORI M. RICE
My Commission Expires
June 7, 2010
Jackson County
Commission #06897298

Coal News and Markets

Coal News and Markets

December 20, 2006

Coal Prices *(updated December 8, 2006)*

This report summarizes spot coal prices for the business weeks ended November 10, 17, 26, and December 1. Based on weekly averages in Platts Coal Outlook, spot prices in all regions except the Powder River Basin (PRB) were unchanged in those five weeks, compared to prior week averages (see table and graph below). The PRB spot coal average declined slightly, from $10.15 to $10.05 per short ton in the week ended November 10, and lost another $0.10, reaching $9.95 in the week ended November 17. In the holiday-shortened week ended November 24 and the week ended December 1, none of the Platts spot prices posted by EIA changed.

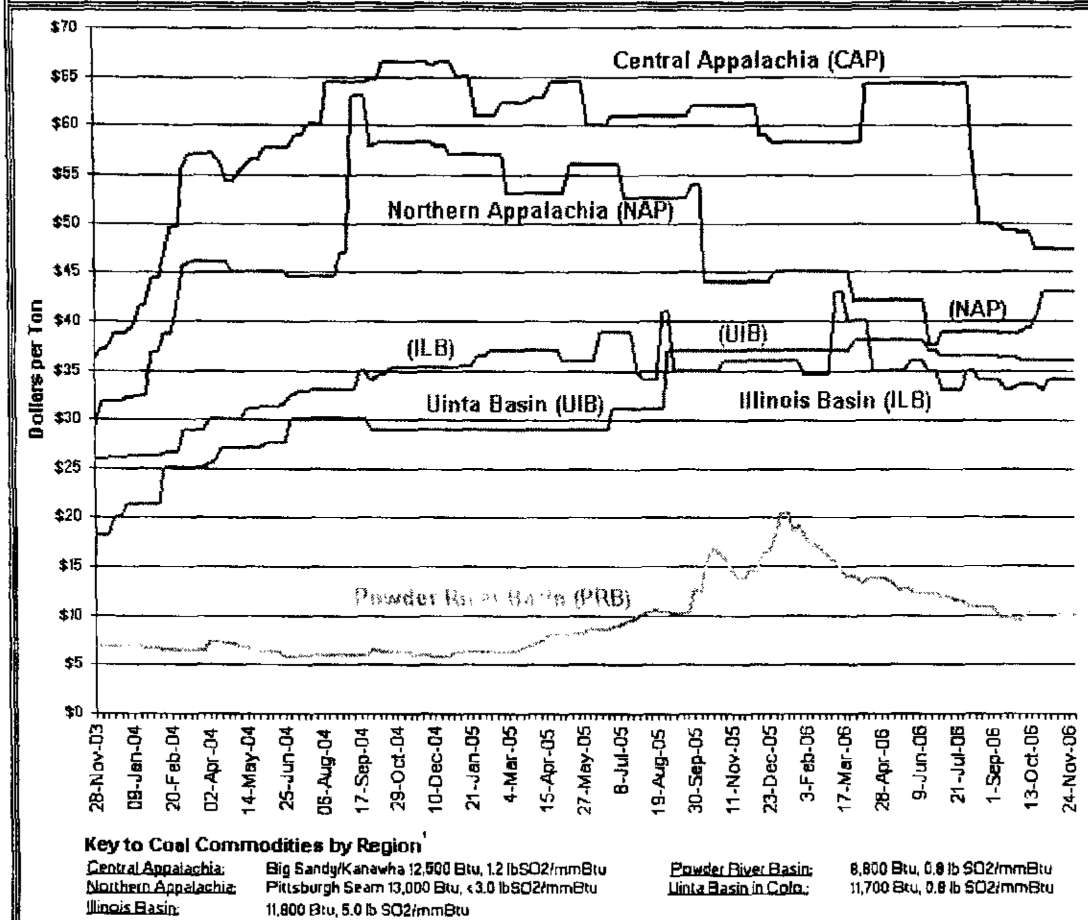
The Central Appalachia (CAP) 12,500-Btu rail coal tracked by the Energy Information Administration (EIA) remained at $47.25 per short ton and the Northern Appalachia (NAP) average spot coal price for 13,000-Btu coal did not change from $43.00 per short ton during the 5-week period. The average spot price for the 11,800-Btu Illinois Basin (ILB) coal held at $34.00 average per short ton during the period. The 11,700-Btu Uinta Basin (UIB) coal commodity continued at $36.00 per short ton; it last changed in the business week ended October 6.

The following average spot coal prices appear in the graphic below, for the previous and most recent weeks:

Week Ended	Central Appalachia 12,500 Btu, 1.2 SO2	Northern Appalachia 13,000 Btu, <3.0 SO2	Illinois Basin 11,800 Btu, 5.0 SO2	Powder River Basin 8,800 Btu, 0.8 SO2	Uinta Basin 11,700 Btu, 0.8 SO2
11/03/06	$47.25	$43.00	$34.00	$10.15	$36.00
11/10/06	$47.25	$43.00	$34.00	$10.05	$36.00
11/17/06	$47.25	$43.00	$34.00	$9.95	$36.00
11/24/06	$47.25	$43.00	$34.00	$9.95	$36.00
12/01/06	$47.25	$43.00	$34.00	$9.95	$36.00

http://www.eia.gov/cneaf/coal/coalnews/coalmar.html

Average Weekly Coal Commodity Spot Prices
Business Week Ended December 15, 2006



[1] Coal prices shown are for a relatively high-Btu coal selected in each region, for delivery in the "prompt quarter." The prompt quarter is the quarter following the current quarter. For example, from January through March, the 2nd quarter is the prompt quarter. Starting on April 1, July through September define the prompt quarter.
Source: with permission, selected from listed prices in Platts Coal Outlook, "Weekly Price Survey."
Note: the historical data file of spot prices is proprietary and cannot be released by EIA; see http://www.platts.com/Coal/. >Analytic Solutions>COALdat, or >Newsletters> Coal Outlook.

The PRB spot prices have not changed in three weeks and the other four Platts regional spot prices posted by EIA have all been unchanged for 5 weeks or longer. Bit by bit spot coal demand has been slowing since early summer. The slackened spot markets are now quiescent. A number of factors contributed to the present lull: concerted efforts that started this past spring to rebuild depleted coal consumer stockpiles with increased deliveries; the opening of shuttered and new mines following the prolonged high coal prices from mid-2004 through early 2006; a relatively mild summer in the service areas of most coal-burning electricity providers; and a mild autumn in most of the eastern United States. Coal stocks in the electric power sector equated to at 44 days' supply (125.6 MMst) as of the end of September. Coal-fired electric power generators were in a better position than in September in either of the previous two years; the most recent time that end-of-September coal stocks were as high as 44 days' supply was in 2003 (see Coal Inventories Section, below).

Coal Supplies *(updated December 11, 2006)*

Conference on Coal Supply Concerns: EIA attended the EUCI Conference, "Getting Enough Coal," held November 2 and 3 in Fort Lauderdale, FL. Most attendees came from the electric power sector. Others represented coal-consuming industries, one coal hauling railroad, energy analysts and consultants, and law firms and lobby groups involved in coal transportation service and rate issues, and active in pushing for new legislation or regulatory measures aimed at railroads. Among the group were representatives of some of the largest coal shippers in the United States.

One of the featured speakers at the conference was W. Douglas Buttrey, a Commissioner and former Chairman of the Surface Transportation Board (STB). At a conference focused on the concerns of shippers over the railroads' reliability and rising transport rates for coal, Mr. Buttrey introduced his talk by noting that the 1980 Staggers Act, which deregulated freight railroads, instructs the STB "to balance the interests of shippers and railroads." Mr. Buttrey noted, "I have yet to meet a business person . . . who really wants a level playing field . . . What that statement really means is . . . 'Take that other guy's advantage away from him and give it to me by government fiat.'" Having noted that his thoughts "do not necessarily reflect official policy of the Board," Mr Buttrey stated: "I firmly believe that to insert the government more into the relationship between shippers and their serving railroads will create more problems than it solves. It makes no sense to me to suggest that a government body in Washington, D.C., should be put in charge of working out the details of important business relationships between coal-fired electric utilities and railroads."

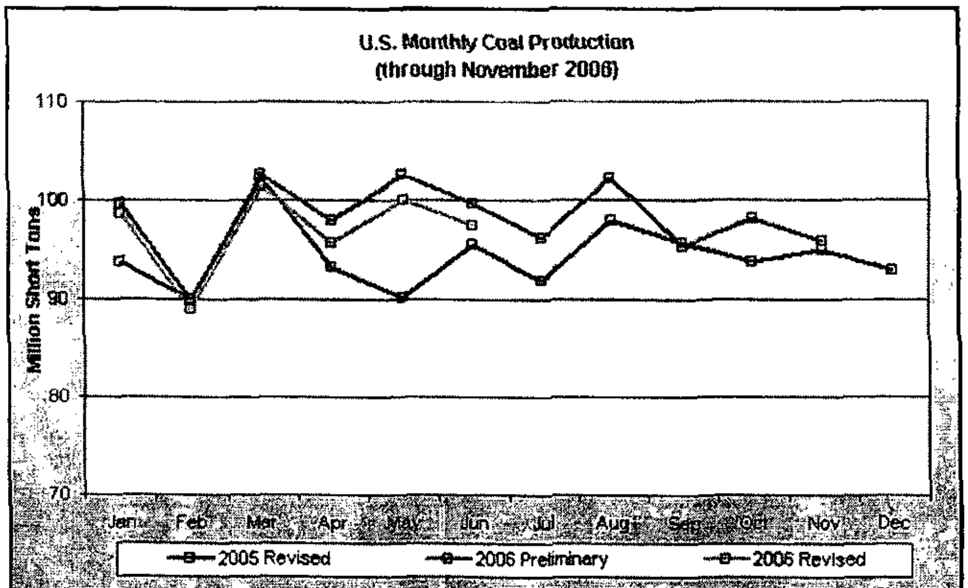
Addressing the fact that the many mergers approved by the STB "have reduced the total number of Class I carriers, and . . . the fact that many coal-fired electric utilities have just one serving railroad," Mr. Buttrey pointed out that "this consolidation has been an essential part of the process of the U.S. railroad industry returning to health from its precarious position in 1980." He warned that "To continue to talk about 'competitive access' and 're-regulation' is counterproductive. Stakeholders should insist that their spokespersons adjust their rhetoric to more productive ideas."

Acknowledging widespread complaints about constrained capacity in the railroads and their rationing of freight traffic capacity, Mr. Buttrey said that the railroads' common carrier obligation has not been changed – they are "still required to provide 'reasonable' service at a 'reasonable' price for regulated traffic. Of course, all relevant factors must be balanced when the Board determines what is 'reasonable' . . ." Those factors include demands on the carriers as well the needs of captive shippers, according to Mr. Buttrey. The STB should be considered a "court of last resort," only to be turned to when the carrier and shipper cannot work out a mutually agreeable solution.

Attendees challenged both Mr. Buttrey's premises and his conclusions, which accepted and projected further increases in rail shipping rates. His message to shippers, who had been protesting continuing rate increases, especially in new transportation contracts, was simply that the increases are justified. In answer to challenges, Mr Buttrey said that railroads have been revenue-inadequate for years and are just beginning to earn adequate revenues. Disagreements were strongly voiced in spirited discussion.

Following Mr. Buttrey's presentation, discussions and later presentations from shipper-oriented speakers brought forth proposals for legislated and regulatory remedies to force competition among the railroads, and possibly legislation to disband the Surface Transportation Board, rescind the railroads' anti-trust immunity, and to argue rate and service disputes directly in Federal courts.

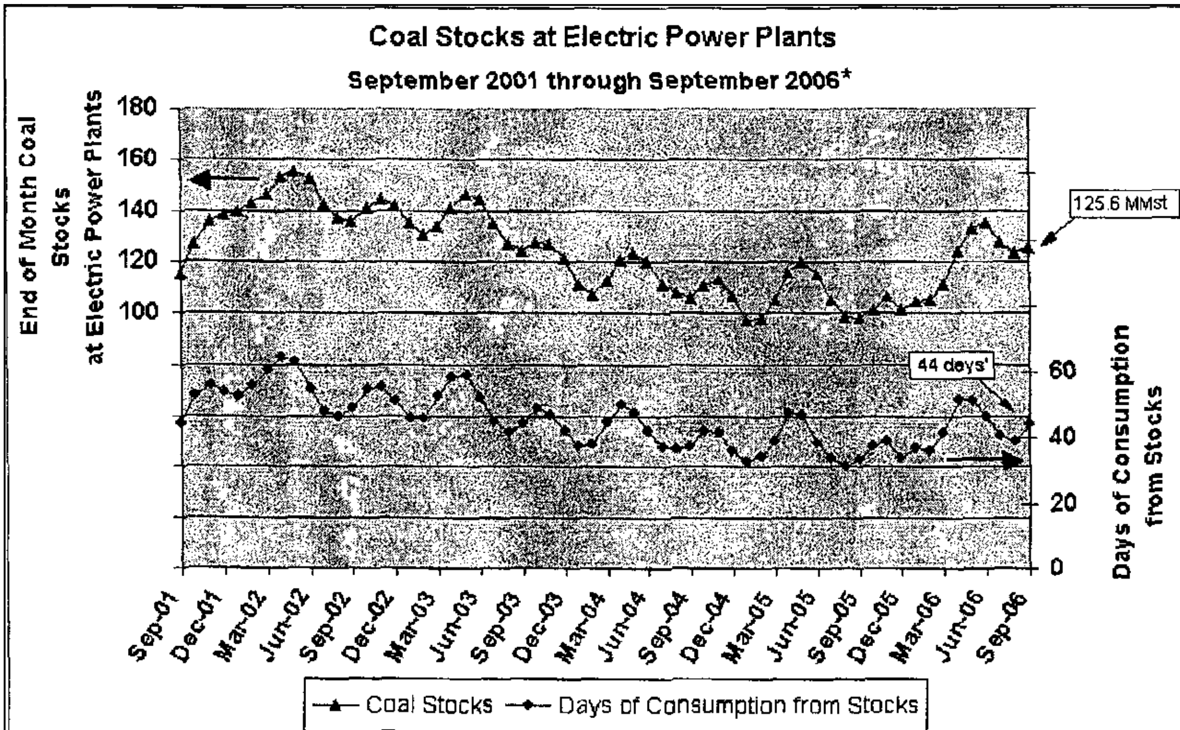
Coal Production - Estimated U.S. coal production for November 2006 was 95.8 MMst (see graph below). The November EIA estimate amounts to a 2.3 percent, or 2.3 MMst, decrease from the October estimate of 98.1MMst. Estimated production in November was slightly higher than 12 months earlier – 95.8 MMst versus 95.0 MMst in November 2005. Production for the first 11 months of 2006 was at record levels, 1,069.5 MMst, or 30.9 MMst ahead of the same period in 2006.



Note: This graph is based on MSHA-based final data all four quarters of 2005, revised production data from MSHA for January through June 2006, and preliminary EIA production estimates for July through September 2006.

The U.S. Monthly Coal Production graph (below) includes final production based on revised mine-level reports for all four quarters of 2005 by the Mine Safety and Health Administration (MSHA). It also shows revised production for January through June 2006 and preliminary EIA Weekly Coal Production estimates for June through September.

Coal Inventories - Coal inventories are monitored at plants that generate electricity (utilities, independent power producers, and industrial and commercial plants with generation capacity). The graph below excludes industrial and commercial plants from coal stocks and days of consumption because it cannot be known what portion of their coal inventories will be used to produce electricity. The number of plants is too small in many cases to ensure individual data confidentiality but the excluded plants constitute only 1 percent to 5 percent of coal-fueled net electricity generation. Thus, the graph below depicts those power plants that comprise the majority (95 to 99 percent) of net electricity generation fueled by coal.

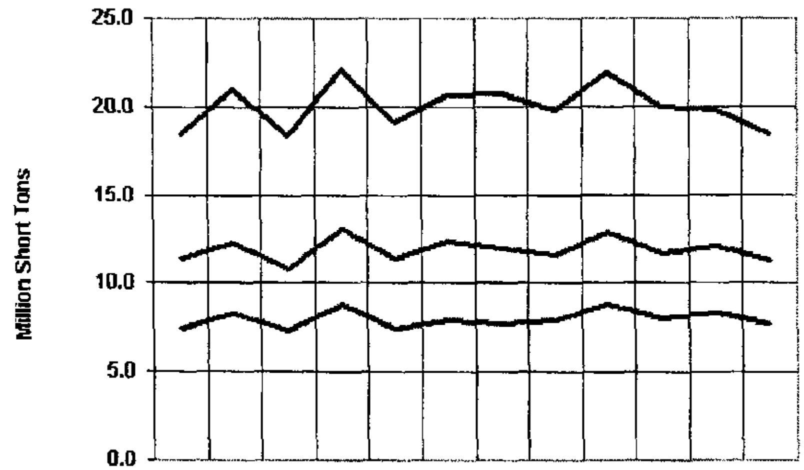


Sources: Electric Power Monthly (EPM) Tables 2.1.A and 3.1; Electric Power Flash Tables 3.2 and 3.3.
* If latest month in Title is marked by "*" data source is Electric Power Flash early-release, which reports consumption for Total Electric Generation; those data are generally about 1 percent higher than later EPM consumption data for the Electric Power Sector alone.

In each month from December 2005 through June 2006, coal inventories at electric power plants had increased from prior month levels. Coal inventories increased by nearly 34 MMst during the 6-month period. On June 30, inventories started the summer 16.3 MMst higher than one year earlier. Further, during the relatively mild summer that followed, the net drawdown in coal inventories was only 11.9 MMst, in contrast to the summer of 2005 when the net drawdown was 21.7 MMst. During the summer, coal inventories declined in July by 7.7 MMst and by 4.1 MMst in August 2006, but by the end of September coal stockpiles were already showing net gains, up 2.3 MMst over August levels. Inventories at the end of August had been well above those of a year earlier when coal stockpiles at electric power plants were affected by last summer's rail disruptions. Inventories were widely acknowledged to be at comfortable margins at most power plants as winter approached. The exception may be some PRB coal customers that have been unable to rebuild to preferred levels, levels that are nonetheless higher than levels considered adequate in September of 2004, before the potential for PRB supply disruptions became a reality. As an indication of PRB inventories, see subbituminous coal in Figure 6.4 of the EIA Flash report.

Eastern mining capacity – Because CAP mines in recent years have been moving into more difficult mining conditions, mine operators have not been able to expand production significantly. Nonetheless, CAP is still the highest producing coalfield in Appalachia. After reaching a high of 281.8 MMst in 1997, CAP annual production decreased as far as 230.1 MMst in 2003. Production increased, however, by 2.4 MMst in 2004 and by 2.8 MMst (to 235.3 MMst) in 2005, or about 1 percent each year. In some months CAP still produces more coal than NAP and ILB combined (see graph below). In the first 9 months of 2006, CAP production was up 2.5 percent over the same period in 2005. First-round production estimates for the months of September, October, and November, however, each declined, confirming company reports of lowered third quarter production and fourth quarter projections. CAP production declined more severely than NAP and ILB production. This validated reports that declining coal demand and prices were cutting into already slim margins at those CAP mines with difficult mining conditions and high operating costs. Numerous temporary mine closures were announced.

12-Month Eastern Coal Production Trends



	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06
Northern App	11.4	12.3	10.8	13.0	11.4	12.3	11.9	11.5	12.9	11.7	12.1	11.3
Central App	18.5	20.9	18.4	22.1	19.1	20.6	20.7	19.7	21.9	19.9	19.8	18.5
Illinois Basin	7.5	8.3	7.3	8.8	7.4	8.0	7.7	8.0	8.8	8.0	8.3	7.7

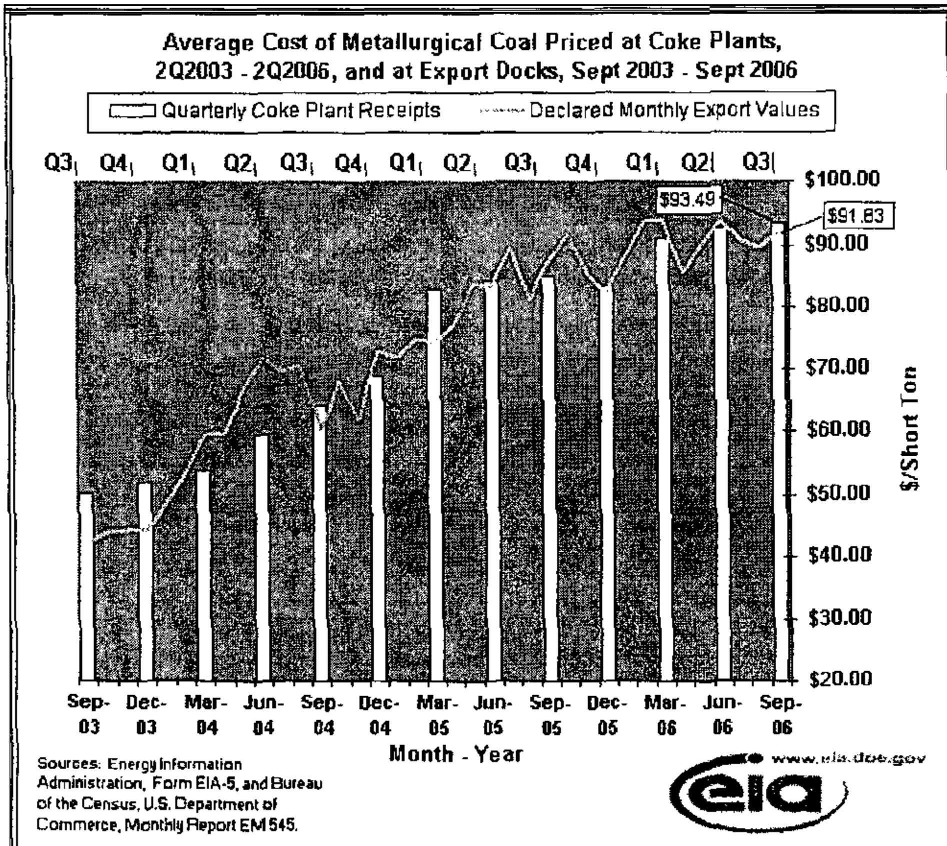
Note: July-November '06 data are preliminary.
(Million Short Tons)

Note: July-September '06 data are initial estimates. Jan-June data are revised. The previous version of this graph and table showed initial estimates for Jan-Mar and revised estimates in 2005. All revisions are based on Mine Safety and Health Administration (MSHA) quarterly mine-level surveys. The revised estimates for Jan-Mar, presented above, should have been shown previously. The 2005 data, though revised, did not contain minor changes resulting from MSHA's end-of-year final survey of all quarters' data. Those changes are incorporated in the Oct-Dec 2005 data above.

Future mining capacity in NAP and ILB is less constrained than in CAP. Deep but relatively thick longwall-minable coal is still accessible in NAP. Large reserves of relatively thick and flat-lying coal are available in ILB, although deeper on average than mined in the past. Additional coal production growth is expected between now and 2011, as many retrofit scrubbers become operational and mines begin burning more high-sulfur coals. Nonetheless, production in those two coalfields has been growing at impressive rates – 3.7 percent in NAP from 2004 to 2005 and 2.8 percent in ILB over the same period. For the first 9 months of 2006, NAP production was 3.4 percent ahead of the same period in 2005 and ILB production was up 3.2 percent. Like CAP production, NAP and ILB production dipped in September, but the combined production of NAP and ILB exceeded CAP production in both October and November, for the first time since December 2005.

Metallurgical Coal *(updated December 13, 2006)*

The graph below, and its downloadable data file include available data through September 2006. The third quarter price data for receipts at coke plants are not yet available. The data show quarterly average values based on coal cost data EIA collects from coke plants. They also depict monthly average values declared for met coal brought to ocean terminals for export, from U.S. Customs data. The values reported do include the costs of transporting the coal to the coke plants or export points.



Download Met Coal data files. (Excel Format)

The second quarter average price at coke plants showed a small increase of $1.63 per short ton in delivered price of metallurgical coal, from $91.09 to $92.72. The monthly average prices for coking coal transported to export docks have stayed within a range of $85 to $94 throughout 2006, and leveling out between $89 and $92 from July through September. Unlike many prices reported in coal newsletters, the values below are based on surveys of actual shipments. These prices are about 2 months old, however, when they are first available. Because the prices are averaged and include met coal shipments from multi-year contracts and traditional 12-month contracts - and not just spot shipments - variances are less extreme than in some spot price reports. Further, it cannot be known from the price data how much of any movement in delivered prices may reflect actual changes in coal priced at the mine versus changes in eastern U.S. rail transportation rates.

Metallurgical coal prices have continued to strengthen since September 2003 and the shock to international coal supplies that occurred in 2004 when exports of Chinese steam coal and metallurgical coke were curtailed. In 2006, met prices have climbed at a slower rate but have reached new average highs amid reports of shortages of steam coal and high met coal demand in China, India, growing coal demand in other East Asia industrial economies.

Accounts of actual individual transactions are relatively few in October and November as the first quarter, January through March, is the period traditionally when most iron and steel producers contract for met coal for the next year or two. Reports that have been seen are mixed for recent met coal price agreements. Jim Walter Resources, reporting on its third quarter sales of Alabama met coal, sold 1.6 MMst of met coal at an average price of $105.48 per short ton, priced at the mine area. That volume is a substantial increase over the 0.7 MMst it sold in 3Q2005, when the coal fetched $108.28 per short ton (Platts Coal Outlook, November 13, p 8.) Third quarter 2006 sales figures for metallurgical coal released by Alberta-based Grand Cache Coal cited 0.3 MM tonnes metric sold for an average $C103, or about $US106 per short ton at the mine (Platts Coal Outlook, November 20, p 9). On the other hand, CRU Monitor, which advises commodity dealers, buyers, and investors, reported in November that U.S. met coal producers that have concluded supply agreements for 2007 purchased premium high–volatile met coal for $69 to $73 per short ton, mid-volatile met coal for about $80 per short ton, and low-volatile met coal for $74 to $82 per short ton (CRU Monitor, Steelmaking Raw Materials, November 2006, p 3).

Coal Transportation *(updated December 13, 2006)*

A Bear Stearns survey of more than 1,000 shippers confirmed what coal-fueled power plant operators believe and the railroad industry says is necessary – that rail transportation rates are rising and expected to continue. Railroad customers, including utilities and coal producers, were surveyed by Bear Stearns analysts and said they expect "strong" rate increases continuing into 2007, driven by "ongoing tight rail capacity and expectations for continued strong rail freight demand." The survey is done quarterly and encompasses a cross section of freight shippers (not only coal). At the time of the survey, third quarter operating costs were not complete but respondents were expecting average rail rate increases of 4.2 percent for the quarter. The second quarter expectations had been for 4.4 percent increases. Rail customers also noted that railroad service improved in the third quarter, especially for CSX customers (Coal Outlook, November 27, pp 8-9.)

Presentations and discussions at the EUCI Conference, "Getting Enough Coal," on November 2 and 3, made it clear that as shippers of large volumes of coal most attendees were not impressed with the Surface Transportation Board's (STB) proposed new large rate case review process, released several days earlier on October 30. As long-time critics of the existing process, the attendees, who were almost all shippers or sympathetic to shippers, felt the proposed changes would make the process worse. Since then, some railroads and an electric co-operative have also announced opposition to the new process, apparently because the new rules could apply to pending as well as future rate cases. Burlington Northern Santa Fe, CSX Railroad, and Norfolk Southern filed separate appeals in the Federal appeals court for the District of Columbia on November 13 and 14. Basin Electric Cooperative of North Dakota had filed on November 9 in the Federal appeals court for the 8th District, in St. Louis. Sources close to the case say the plaintiffs are aggrieved because the STB put on hold plaintiffs' appeals that were months or years old while developing its proposed new review process, and because that process would now cause them further expense to argue and defend their rate cases at the STB under the new rules, further delaying the STB decisions. Echoing sentiments expressed at the EUCI conference, Bob Szabo, Director of Customers United for Rail Equity said coal shippers believe that the STB's new rules "will make it virtually impossible to win a rate reasonableness case at the STB" (Coal Outlook, November 27, p10).

Previous Coal News and Markets Reports

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Chairman's Letter

To Our Owners

Over the past year, we have followed a well-defined strategy to capitalize on our generating assets, grow earnings, reduce costs and effectively manage regulatory and market uncertainties. We have enhanced the performance of our existing assets and made necessary investments to prepare for an increasingly competitive environment. That strategy has proved both durable and successful.

We continue to seek opportunities to maximize our generating assets. Ameren ranks 11th in the nation in generation capacity. 1998 was marked by several initiatives to secure and enhance this position by increasing the availability of our coal-fired plants and sustaining the already strong performance of our nuclear unit. Our Labadie and Rush Island plants set all-time generation records in 1998, while our Callaway Nuclear Plant needed only 31 days to complete its ninth refueling, tying the record set during the plant's last refueling in the fall of 1996. This record was the second shortest of any of the 27 nuclear plant refuelings conducted in the spring of 1998. Callaway continues to rank as one of the nation's best managed nuclear plants, earning recognition for operating efficiency and safety in a period of increased regulatory scrutiny.

These generation resources paid dividends in the summer of 1998 when utilities were paying unprecedented prices for power purchases. We effectively managed power costs in the face of soaring wholesale electricity prices, and these abnormally high prices had little impact on Ameren's financial results, unlike the experience of several other utilities. The year also marked further development of our energy trading and marketing affiliate. AmerenEnergy is now poised to capitalize on Ameren's strong generation assets. Finally, in 1998 we signed contracts that set the stage for the installation of combustion turbines that, by the year 2001, will add more than 700 megawatts to our generating capacity. We continue to grow earnings through core business development and investment in new products and energy-related ventures. We are developing a stream of attractive products and services that will benefit our customers and enhance our company's earnings growth. These include a number of technologically sophisticated products, from an automated bill consolidation service Ameren Ability to an energy management product Ameren Abacus that allows business or institutional customers to track energy use by process, building or facility.

Another of Ameren's major ventures involves partnerships with design and engineering firms. Foremost among these is Gateway Energy Systems, a firm that desugns, builds, finances, owns and operates utility systems for large institutional and industrial customers. In 1998, Gateway Energy sealed a 20-year contract to build a $20 steam facility for a Fortune 500 company.

We continue to reduce costs by increasing operating efficiency through the effective use of technology. These initiatives range from installation of remote sensing devices on our distribution lines to expansion of our automated meter system — now the world's largest. We are also focused on lowering fuel costs. n 1998 in Illinois, we chose to eliminate the fuel adjustment clauses, which called for offering credits if certain fuel costs dropped or increasing customer bills if they rose. That decision, coupled with the fact that we have operated for several years without a fuel adjustment clause in Missouri, has given us additional incentive to continue to manage our fuel costs effectively. Our four AmerenUE coal-fired power plants continue to use substantial quantities of lower cost, low-sulfur Western coal, reducing production costs and emissions. In 1998, AmerenCIPS' Newton Plant began using Western coal. We will continue to aggressively explore these and other options to reduce our fuel costs.

In addition, we realize that increased productivity is critical to controlling operating costs. In 1998 we eliminated more than 400 positions, essentially without layoffs, through a hiring freeze and a targeted separation plan. These reductions will yield savings of approximately $20 million to $25 million annually.

Ameren's entire work force now stands at approximately 7,450 employees — the level of employment for Union Electric alone in 1987. Compared to a decade ago, Ameren companies are serving 8% more customers — with 24% fewer employees. In 1998, Public Utility Fortnightly, a leading industry publication, recognized Ameren as one of the nation's most efficient utilities, ranking our company as the second "most improved" and 11th most efficient.

Earnings Per Share

*Excluding an extraordinary charge of $.38.

We will continue to improve our efficiency as we refine our strategies and determine the skills that are most important in meeting the challenges of a competitive environment.

Finally, we are effectively managing the market and regulatory uncertainties we face by remaining visible and active in the industry restructuring debate and on other issues. We have continually communicated to a range of government officials that we cannot support initiatives aimed at increasing competition in ways that do not adequately protect our shareholders and our customers.

On the environmental front, we are using our resources to propose alternatives to the several stringent, technically flawed regulations that federal environmental officials proposed and established in 1998. We continue to research, investigate and test technologies that offer workable and affordable alternatives.

Going forward, our strategy's operating model will increasingly be based on a business line approach. These business lines include generation; energy transmission and distribution; retail customer service; business and corporate services; and non-regulated operations. Business line teams spent 1998 planning and developing strategies that will yield added revenue and cost savings.

These efforts will keep our management and employees focused on the specific strategies that bring bottom line results in an ever-changing competitive environment. As we mark the completion of our first full year as Ameren Corporation, we can tell you that our strategy has brought results.

1998 Financial Performance In 1998, our company earned $386 million, or $2.82 per share. This compares to 1997 earnings of $335 million, or $2.44 per share, including a 1997 extraordinary charge. That charge of $52 million, net of income taxes, reduced 1997 earnings 38 cents per share. Excluding nonrecurring charges, ongoing earnings for 1998 were $2.93 per share, compared to $2.77 per share for 1997.

Electric revenues were up slightly in 1998 over 1997, despite rate decreases and a $43 million credit to Missouri electric customers. These reduced earnings 6 cents and 18 cents per share, respectively. Kilowatthour sales to retail customers within our service territory were up 4%. Our annual sales growth — in a now-expanded, economically strong service area — stands at better than 2%.

Electric Industry Restructuring in Illinois Ameren continued to develop technology, organize staffs and contribute to working groups the state created to respond to the multiple requirements of 1997 legislation setting the stage for provider choice. Certain large commercial and industrial customers in Illinois can choose their energy providers in late 1999, with all business and residential customers able to choose providers by May 2002. The law also called for a 5% rate reduction that began Aug. 1, 1998, for our Illinois residential customers. That rate decrease is expected to reduce future annual revenues by approximately $14 million ($8 million over 1998).

Electric Industry Restructuring in Missouri Missouri legislators and regulators continue to analyze the issue of provider choice. As members of various restructuring task forces and committees, Ameren's managers continue to be very active in promoting the interests of its investors and customers.

In Summary Ameren Corporation is a stronger and

Service Area

more focused company than ever before. We are confident that our operating performance, growth initiatives and strategic direction will make Ameren a success in any competitive environment.

We are investing in the people, technology and facilities that support our core energy business. Through our merger and direct sales initiatives, we are expanding our market area and customer base. We continue to develop products that retain and attract customers, as we selectively pursue non-regulated business opportunities. While we do not underestimate the challenges, we enter the new era committed to returning value to you, our shareholders.

Going forward, we are enthusiastic about the opportunities that are open to a financially strong company, like ours. We realize that you will be best served by a company that can maintain its low-cost advantage, meet customers' total energy needs and deliver superior earnings growth.

Our thanks go to our employees and to our dedicated directors who have been actively involved in charting our course.

Sincerely,

Charles W. Mueller

Chairman, President and Chief Executive Officer

February 10, 1999