BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of an Investigation of the Cost to Missouri's Electric Utilities Resulting from Compliance with Federal Environmental Regulations	))))	**File No. EW-2012-0065**

STAFF REPORT AND RECOMMENDATION TO ALLOW FILE TO REMAIN OPEN

COMES NOW the Staff ("Staff") of the Missouri Public Service Commission ("Commission"), and for its *Report and Recommendation to Allow File to Remain Open* states as follows:

1. On August 30, 2011, in its *Order Opening an Investigation into the Cost of Compliance with Federal Environmental Regulations*, the Commission directed Staff "to lead a working group to investigate and to draft a report describing the effects of [Federal] environmental regulation on Missouri's electric industry and to offer recommendations on how this Commission should address the effects."

2. As discussed more fully in Staff's *Report*, attached as Appendix A, based on Staff's analysis, the overall cost to the electric utilities and potentially their customers related to existing Federal environmental regulation would be in an approximate range of $1,981,000,000 to $3,276,000,000. Future rules could increase this estimate or the range of the estimate.

3. Staff recommends that the Commission allow this File to remain open. Staff anticipates the need to file supplemental information as issues are further identified and additional actions are taken by other regulatory agencies.

WHEREFORE, Staff submits its *Report and Recommendation to Allow File to Remain Open* in compliance with the Commission's August 30, 2011 *Order Opening an Investigation into the Cost of Compliance with Federal Environmental Regulations*.

Respectfully submitted,

/s/ Sarah L. Kliethermes
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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed, hand-delivered, transmitted by facsimile or electronically mailed to all counsel of record this 1st day of May, 2012.

/s/ Sarah L. Kliethermes

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT ON

THE COST OF COMPLIANCE WITH FEDERAL ENVIRONMENTAL REGULATIONS

FILE NO. EW-2012-0065

Jefferson City, Missouri
May 1, 2012

Appendix A

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REPORT REGARDING THE COST OF COMPLIANCE WITH FEDERAL ENVIRONMENTAL REGULATIONS

EXECUTIVE SUMMARY

The Missouri Public Service Commission (Commission) issued an order on August 20, 2011, directing the Commission Staff (Staff) to lead a working group including utility, industrial, consumer, and environmental stakeholders, to investigate and file a report regarding the cost of compliance with Federal environmental regulations. Staff conducted two workshop meetings (October 26, 2011 and February 7, 2012). Information was obtained from a variety of sources as detailed in the body of this report. Based on analysis of this information, the overall cost to the electric utilities and potentially their customers would be in an approximate range of $1,981,000,000 to $3,276,000,000. This estimate is based on compliance with the rules that have been issued. Future rules could increase this estimate or the range of the estimate.

Staff recommends that the Commission allow this File to remain open. Staff anticipates the need to file supplemental information as issues are further identified and additional actions are taken by other regulatory agencies.

Note: Throughout this report, information has been obtained from various sources. Significant portions of this report were obtained directly from various documents, presentations, and/or websites prepared or sponsored by Missouri utilities, utility industry organizations, regional transmission system operators, federal agencies, and others.

HISTORY

The Clean Air Act of 1970 authorized the development of comprehensive federal and state regulations to limit emissions from stationary and mobile sources. Four major regulatory programs affecting stationary sources were initiated: the National Ambient Air Quality Standards (NAAQS), State Implementation Plans (SIPs), New Source Performance Standards, and National Emission Standards for Hazardous Air Pollutants. The National Environmental Policy Act created the United States Environmental Protection Agency (EPA) on December 2, 1970. Major amendments to the Clean Air Act occurred in 1977 and 1990. The legal authority for federal programs regarding air pollution control is based on the 1990 Clean Air Act Amendments. These are the latest in a series of amendments made to the Clean Air Act (CAA). This legislation modified and extended federal legal authority provided by the earlier Clean Air Acts of 1963 and 1970.

In 2005, the EPA finalized the Clean Air Interstate Rule (CAIR). A 2008 court decision left the CAIR requirements in place temporarily and directed the EPA to issue a replacement rule. CAIR covered SO_2 and NO_X and affected Missouri but not Kansas. The EPA finalized the Cross States Air Pollution Rule (CSAPR) on July 6, 2011. CSAPR requires substantial near-term emission reductions. Unlike CAIR, CSAPR affects both Missouri and Kansas. CSAPR controls SO_2 and NO_X and includes four allowance trading programs: annual NO_X, ozone-season NO_X, Group 1 SO_2, and Group 2 SO_2. The two groups for SO_2 trading are significant for Missouri utilities because Missouri is in Group 1 and Kansas in Group 2. This would prevent Empire and KCP&L from utilizing a common trading program between their Kansas and Missouri generating plants. Arkansas is affected by CSAPR for only ozone-season NO_X. The CSAPR emission budgets are based on the EPA's state-by-state analysis of upwind state's contributions to nonattainment and interference in downwind states. Interstate trading is limited by setting assurance provisions designed to ensure that no state's emission allowances are allowed to exceed that specific state's budget allowances. State budgets and assurance levels are summarized in the following tables. Emission reductions under the Cross-State Air Pollution Rule would take effect quickly. The first phase of compliance begins January 1, 2012 for SO_2 and annual NO_X reductions and May 1, 2012 for ozone season NO_X reductions. The second phase of SO_2 reductions begins January 1, 2014. By 2014, CSAPR and other final state and EPA actions will reduce power plant SO_2 emissions by 73 percent from 2005 levels. Power plant NO_X emissions will drop by 54 percent. In December 2011, a court ruling stayed CSAPR and left CAIR in effect temporarily. Oral arguments were heard on Friday, April 13, 2012 regarding the legal challenges to CSAPR. A decision could be forthcoming in June or July, 2012.

State	SO_2 Group	2012 SO_2 Budget (Tons)	2014 SO_2 Budget (Tons)	2012 SO_2 Assurance Level (Tons)	2014 SO_2 Assurance Level (Tons)
Kansas	2	41,528	41,528	49,003	49,003
Missouri	1	207,466	165,941	244,810	195,810

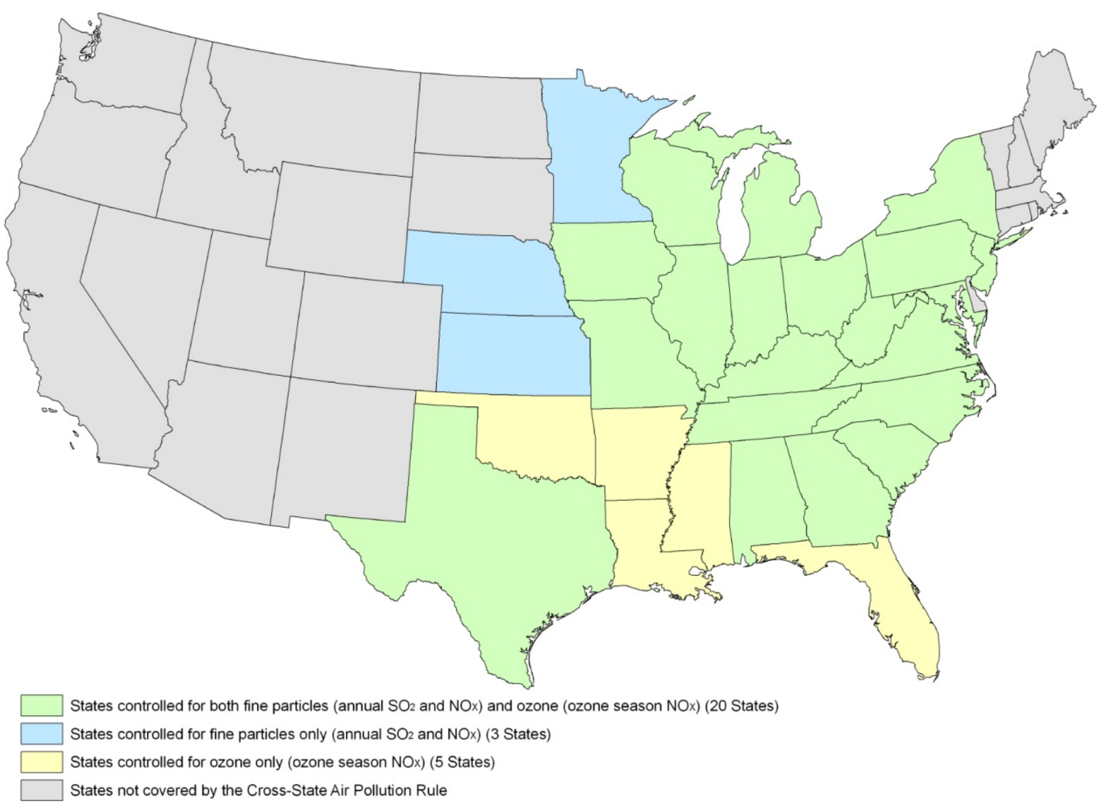
State	2012 NO_X Annual Budget (Tons)	2014 NO_X Annual Budget (Tons)	2012 NO_X Annual Assurance Level (Tons)	2014 NO_X Annual Assurance Level (Tons)
Kansas	30,714	25,560	36,243	30,161
Missouri	52,374	48,717	61,801	57,486

State	2012 NO_X Ozone Season Budget (Tons)	2014 NO_X Ozone Season Budget (Tons)	2012 NO_X Ozone Season Assurance Level (Tons)	2014 NO_X Ozone Season Assurance Level (Tons)
Arkansas	15,037	15,037	18,195	18,195
Missouri	22,762	21,073	27,542	25,498

For comparison purposes, 2010 emissions data for certain state emissions under previous clean air regulations are provided in the table below.

State	SO_2 (Tons)	Annual NO_X (Tons)	Ozone Season NO_X (Tons)
Arkansas			18,300
Missouri	236,191	58,221	25,569

The following map illustrates the United States CSAPR requirements.



The following table summarizes the CSAPR requirements for the three states that contain coal-fired electrical generating units utilized by Missouri utilities.

State	Required to Reduce Emissions of NO_X during the Ozone Season (1997 Ozone NAAQS)	Required to Reduce Annual Emissions of SO_2 and NO_X (1997 Annual PM2.5 NAAQS)	Required to Reduce Annual Emissions of SO_2 and NO_X (2006 24-hour PM2.5 NAAQS)	SO_2 Group
Arkansas	X			
Kansas			X	2
Missouri	X	X	X	1

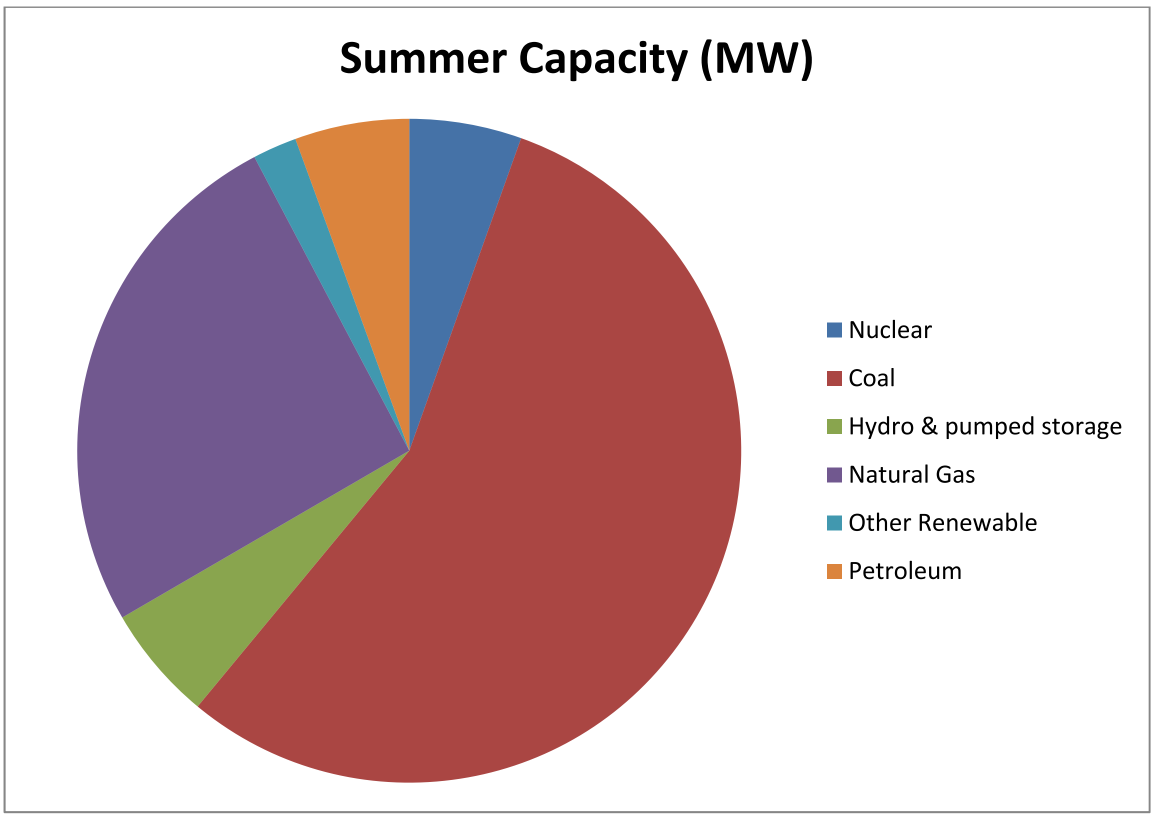
On March 15, 2005, EPA issued the final Clean Air Mercury Rule (CAMR). CAMR established "standards of performance" limiting mercury emissions from new and existing utilities and created a market-based cap-and-trade program to reduce nationwide utility emissions of mercury in two phases. On February 8, 2008, the District of Columbia Circuit Court of Appeals vacated CAMR. On March 16, 2011, EPA proposed a rule that would reduce emissions from new and existing coal- and oil-fired power plants. This proposed rule would replace the court-vacated Clean Air Mercury Rule. On December 16, 2011, the EPA issued a rule to reduce emissions of toxic air pollutants from power plants. Specifically, the Mercury and Air Toxics Standards (MATS) for power plants will reduce emissions from new and existing coal- and oil-fired electric utility steam generating units. EPA also issued revisions to the New Source Performance Standards (NSPS) for fossil-fuel-fired electric generating units (EGUs). This NSPS revises the standards that new coal- and oil-fired power plants must meet for particulate matter (PM), SO_2, and NOx. Existing sources generally will have up to 4 years if they need it to comply with MATS. This includes the 3 years provided to all sources by the Clean Air Act. EPA's analysis continues to demonstrate that this will be sufficient time for most, if not all, sources to comply. Under the Clean Air Act, state permitting authorities can also grant an additional year as needed for technology installation. EPA expects this option to be broadly available. The final MATS rule took effect on April 16, 2012 (starting a three-year compliance period). A significant number of legal challenges have been filed against the MATS rule. EPA recently issued proposed revisions to the NSPS for EGUs to add a section on greenhouse gas (GHG) for new and modified facilities.[1]

[1] Entire "History" section, various sources, EPA.

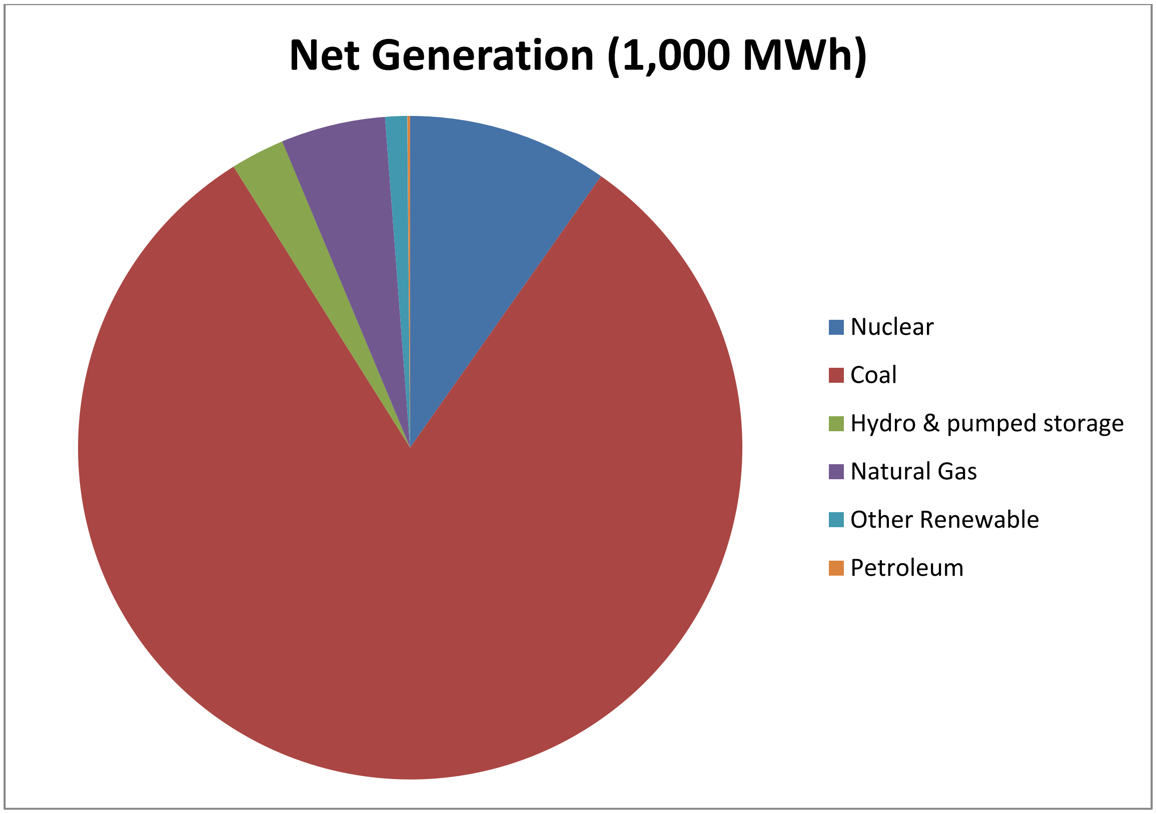
BACKGROUND INFORMATION

The environmental regulations that were reviewed primarily affect coal-fired generating plants. The Missouri electric utilities utilize coal-fired generating plants located in three states—Missouri, Kansas, and Arkansas. Total Missouri-jurisdictional generating capacity for these units is approximately 9,000 MW. Total generating capacity for these units is approximately 13,700 MW.

On a geographic basis, Missouri ranks 18th in the United States for generating capacity (total net summer capacity) and net generation. On the same basis, Missouri ranks 8th for SO_2 emissions, 18th for NO_X emissions, and 10th for carbon dioxide (CO_2) emissions. The following two charts illustrate the Missouri generating capacity (Summer 2010) and net electrical generation (2010). The total summer capacity was 21,739 MW and the total net generation was 92,313,000 MWh. These charts are developed on a geographical basis, not Missouri investor-owned utility jurisdictional basis.[2]

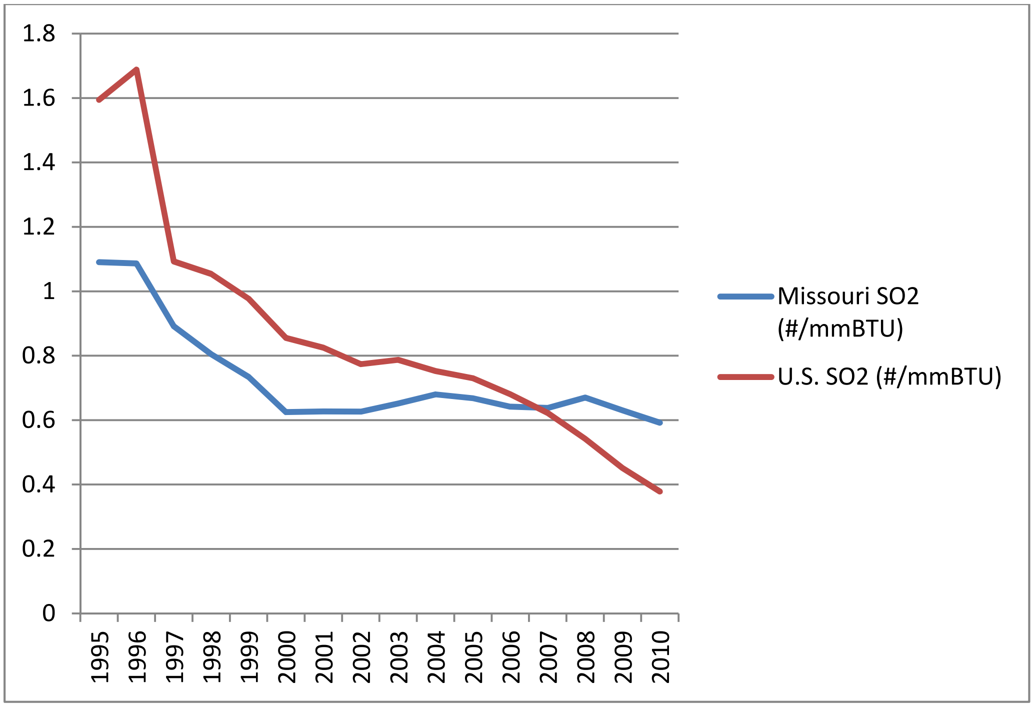


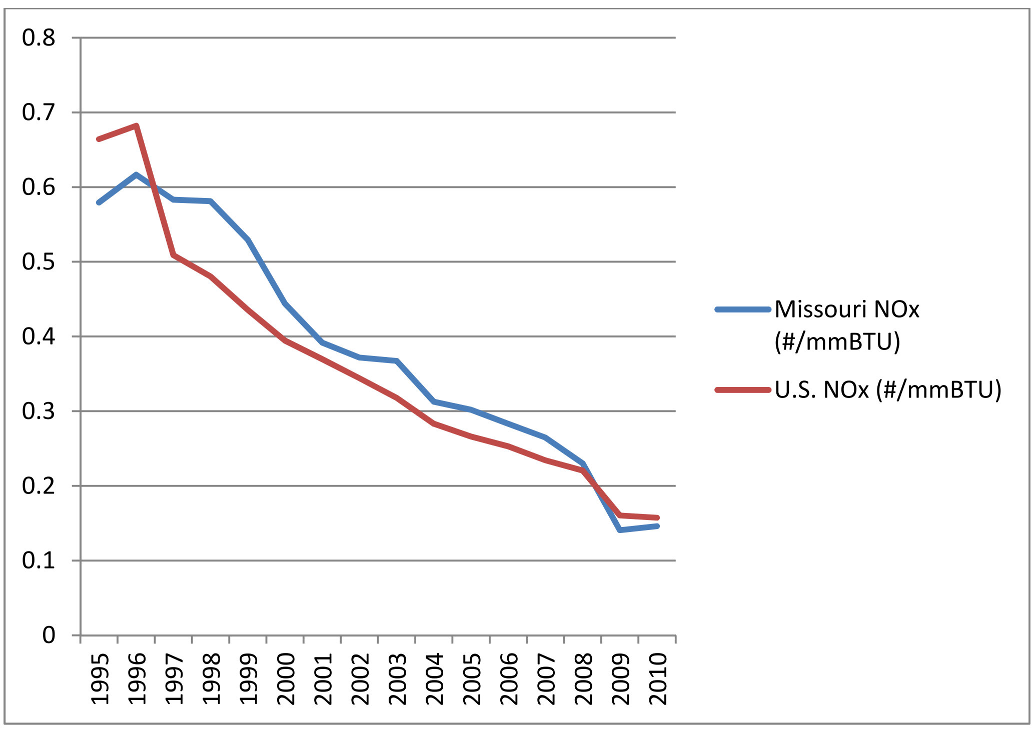
[2] State Electricity Profiles 2010, U.S. Energy Information Administration (EIA), January 2012.



For a historical perspective, Missouri SO_2 and NO_X coal-fired generating plant emissions were compared with total United States emissions on a pound per million BTU (#/mmBTU) basis. The data analyzed was from 1995 through 2010. For 1997 through 2010, forty eight states and the District of Columbia were included. For 1995 and 1996, twenty four and twenty three states respectively, were included. The data for Missouri included all coal-fired generating plants physically located in Missouri. The data does not include generating plants utilized by Missouri utilities that are located outside Missouri.[3]

[3] Air Markets Program Data website, EPA.





Utilizing approximations, the relative cost of emissions control technologies are flue gas desulfurization (FGD) costs approximately two to three times a selective catalytic reduction unit (SCR) or a baghouse. Wet cooling tower costs are approximately equal to a SCR or baghouse. Activated carbon injection (ACI) for mercury control is approximately five percent of the SCR or baghouse cost.

Installation of all the emission controls technologies (except ACI) requires extensive construction activities and normally a generating unit outage for the tie-in of the new equipment. Significant amounts of the construction work can be accomplished without affecting generating unit operation prior to the tie-in outage. In some cases, earlier generating unit outages are utilized for preliminary construction activities in anticipation of the tie-in outage. Installation of emission control technologies can result in support equipment upgrades and modifications. Examples could include, but not be limited to: new or modified chimney, upgraded electrical systems, modified or upgraded instrument and control system, or new or modified waste disposal systems. For multiple unit sites, shared common equipment can be used to support similar systems on all the units.

From the Missouri utilities' current perspective, CSAPR and MATS are the predominant regulatory actions necessitating specific generating plant modifications or other compliance methodologies. Other rules could be forthcoming that would impose additional requirements.

WORKSHOP PRESENTATIONS

At the initial workshop meeting (October 26, 2011), information was presented by the electric utilities, MISO, SPP, and the Sierra Club. The summary utility presentation, and the individual utility, MISO, SPP, and Sierra Club presentations are included in Case No. EW-2012-0065. Information from these presentations is summarized below.

Summary Utility Presentation

The summary utility presentation included an overview of the pending EPA regulations. The pertinent regulations/rules are listed below.

Air Rules

- Clean Air Interstate Rule (CAIR)
- Cross-State Air Pollution Rule (CSAPR)
- Power Plant Mercury and Air Toxics Standards (MATS)
- Sulfur dioxide, Ozone, and Particulate Matter National Ambient Air Quality Standards (NAAQS)
- Regional Haze / Best Available Retrofit Technology Rule (BART)
- Industrial Boiler Maximum Achievable Control Technology Rule (Industrial Boiler MACT)
- Green House Gas Rules

Water Rules

- Clean Water Act 316(a)
- Clean Water Act 316(b)
- Effluent Limitation Guidelines

Waste Rule

- Coal Combustion Residuals Rule (CCR)

Compliance options for SO_2 include: fuel switching, purchase of SO_2 allowances (if available), reduction in generation, dry sorbent injection, or scrubbing equipment. Compliance options for NO_X include: aggressive tuning of existing units, low NO_X burners, additional over-fired air, purchase NO_X allowances (if available), reduction in generation, selective non-catalytic reduction (SNCR) equipment, or SCR equipment. Compliance options for MATS include: electrostatic precipitator upgrades, baghouses, wet or dry scrubbers, dry sorbent injection, ACI, and/or fuel additives.

Compliance options for Clean Water Act [316(b)] rules could include: fish friendly collection and return systems (enhanced traveling water screens), reduced through-screen velocity, fine mesh screens, or cooling towers. Compliance options for Clean Water Act [316(a)] rules could include: thermal and biological studies, cooling towers, or reduced generation. Coal combustion residuals compliance options could include various changes regarding landfills and ponds.

Union Electric Company d/b/a Ameren Missouri (Ameren Missouri)

Recent environmental upgrades provide compliance improvements. The installation of scrubbers on Sioux Units 1 and 2 and fuel switching to ultra-low sulfur coal will provide environmental benefits. Compliance plans for SO_2 include: utilization of ultra-low sulfur coal, banking SO_2 credits, and evaluation of ultra-low sulfur coal vs. emissions control equipment for 2018 and beyond. Compliance plans for NO_X include: aggressive tuning of units, additional over-fired air modifications, NO_X allowance purchases and/or swap of SO_2 for NO_X allowances, or reduction in generation. Compliance for MATS could include: electrostatic precipitator upgrades, activated carbon injection, or fuel additives. Compliance with Clean Water Act rules could include: technology and biological studies; dependent on re-issued NPDES permits. *Note: Portions of the material in the Ameren Missouri presentation were deemed Highly Confidential and are not included in this report.*

Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations Company (GMO)

Recent environmental upgrades and new generating unit construction provide compliance improvements. The installation of an SCR at La Cygne Unit 1, SNCR on Sibley Units 1 and 2, SCR on Sibley Unit 3, SCR, scrubber, baghouse, and ACI at Iatan Unit 1, upgraded scrubbers on Jeffrey Energy Center Units 1, 2, and 3, and Iatan Unit 2 with SCR, scrubber, baghouse, and ACI will provide environmental benefits for KCP&L and GMO. Additional compliance plans are in progress that affect these and other generating units. Compliance plans for SO_2 include: scrubber installations, fuel switching, and reduction in generation. Compliance plans for NO_X include: installation of SCR, installing low-NO_X burners, reduction in generation, and increasing emission reductions from existing SCRs and SNCRs. Compliance for MATS could include: activated carbon injection, electrostatic precipitator upgrades, baghouse installation, dry sorbent injection, and fuel switching.

The Empire District Electric Company (Empire)

Recent environmental upgrades and new generating unit construction provide compliance improvements. The installation of an SCR at Asbury, SCR, scrubber, baghouse, and ACI at Iatan Unit 1, Iatan Unit 2 with SCR, scrubber, baghouse, and ACI, and Plum Point Unit 1 with SCR, scrubber, baghouse, and ACI will provide environmental benefits for Empire. Compliance plans for SO_2 include: scrubber installation, fuel switching, and retirement of units. Compliance for MATS could include: scrubber installation, baghouse installation, ACI, fuel switching, and retirement of generating units.

MISO

The MISO presentation was developed based on the proposed CSAPR, not the final CSAPR. While some changes were made in the final rule, most of the underlying assumptions remained constant. MISO estimated that approximately 12,600 MW of coal-fired generating unit capacity would be at-risk, necessitating capital investment of approximately $32.5 billion to retrofit and/or replace the units. Energy prices could increase from $1 to $5 per MWh. Uncertainties could drive these numbers higher. Estimates for transmission system investments associated with the at-risk 12,600 MW would be approximately $880 million. Based on MISO's evaluation, the system reserve margin would not be maintained.

SPP

SPP performed reliability modeling evaluations of its system utilizing assumptions from EPA analysis. One of the modeling assumptions was removal of any SPP generating units which showed zero fuel consumption in the EPA analysis (114 generating units with aggregate nameplate capacity of 10,900

MW). Examples of concerns identified by the SPP analysis were: 16 overloads above 120% of emergency ratings for N-1 contingences, 93 circumstances with low voltage for N-1 contingencies, and 11 contingencies that would not solve within the model. Those scenarios represent circumstances under which drastic measures might be required. The results of the modeling showed Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) violations for the summer 2012 peak conditions if EPA modeling assumptions were deployed.

Sierra Cub

With regard to Missouri regulated generating facilities, the Sierra Club recommended that the Commission consider the following:

- Whether the generation capacity is needed (or is it excess);
- If the capacity is needed, whether the utility has a plan for compliance with all public health and environmental regulations; and
- Whether that compliance plan is reasonable and prudent.

The Sierra Club also provided "Questions the PSC should ask":

- What (if any) planning has the utility done to prepare for compliance with existing and emerging regulations?
- What were the results of these planning processes?
- How will the compliance plan impact rates?
- When was the utility's most recent RFP for wind and what were the $/MWh bid responses?
- When was the utility's most recent RFP for existing natural gas energy and/or capacity and what were the $/MWh bid responses?
- Is the utility on track to meet RPS obligations in the states where it is regulated?
- For each unit in their respective fleets:
    - What retrofits are planned for compliance?
    - When will those retrofits take place?
    - What is the anticipated cost of those retrofits on a $/MWh basis?
    - Which plants will be closed rather than retrofit?

WORKSHOP FOLLOW-UP COMMENTS

Following the initial workshop, additional comments were received from Dogwood Energy, LLC and The Sierra Club. The additional comments are included in Case No. EW-2012-0065. Information from the comments is summarized below.

Dogwood Energy, LLC (Dogwood Energy)

The Dogwood Energy comments highlighted information regarding the Dogwood Energy generating facility near Pleasant Hill, Missouri. The Dogwood Energy facility is a 650 MW natural gas-fired, combined-cycle plant. Because of the inherent facility design, the generating units operate at a high efficiency (50%) and low emission levels. Missouri electric utilities have purchased power from Dogwood Energy in the past. Dogwood Energy anticipates that approximately half of its capacity and energy may be sold to municipal utilities and power pools by mid-year 2012 and by the end of 2012, Dogwood Energy's ownership of the capacity at the Dogwood facility may be reduced to approximately one-third. Beyond 2013 or 2014, the Dogwood facility capacity may be completely allocated to utilities or power pools located in Missouri or adjacent states. If a utility wants to mitigate environmental compliance costs by using the Dogwood plant as an alternative cleaner source of generation, it will need to act relatively quickly.

Sierra Club

The Sierra Club submitted detailed comments regarding: current EPA activities, utility resource planning, known or potential impacts on coal-fired generating units, and recommendations regarding potential Commission actions. The Sierra Club recommends that the Commission utilize an "Integrated Environmental-Compliance Planning" approach, noting that this would address several identified "shortcomings" in the current electric utility resource planning process.[4] Additional comments are provided that address specific aspects of the current electric utility resource planning process.[5] The Sierra Club provided tables and figures illustrating estimated compliance costs for all coal-fired generating plants physically located in Missouri. The comments also include information regarding the use of renewable energy sources, demand response programs, and energy efficiency.

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[4] This recommendation goes beyond the extent of this report as it addresses concepts not addressed in the current Commission rules and could affect electric service providers that are not regulated by the Commission.

[5] These comments would be more pertinent to the cases associated with those topics.

SUBSEQUENT INFORMATION

Additional information was received subsequent to the October workshop and follow-up comments. The Sierra Club provided revised tables regarding compliance costs for the coal-fired generating plants physically located in Missouri. These tables are filed in EW-2012-0065. Staff provided a summary spreadsheet that lists details regarding the coal-fired generating plants that serve Missouri investor-owned electric utility customers. This item is included in this report as Appendix D.

Utilizing the cost estimates provided in the Sierra Club tables, the following capital expenditures could be required to comply with existing and proposed EPA regulations.[6]

FGD – Flue Gas Desulfurization SCR – Selective Catalytic Reduction BH – Bag House
ACI – Activated Carbon Injection CT – Wet Cooling Tower

Ameren Missouri		
Labadie 1	FGD, SCR, BH, ACI (CT)	$485,000,000 ($95,000,000)
Labadie 2	FGD, SCR, BH, ACI (CT)	$484,000,000 ($96,000,000)
Labadie 3	FGD, SCR, BH, ACI (CT)	$515,000,000 ($101,000,000)
Labadie 4	FGD, SCR, BH, ACI (CT)	$515,000,000 ($101,000,000)
Meramec 1	FGD, SCR, BH, ACI (CT)	$165,000,000 ($19,000,000)
Meramec 2	FGD, SCR, BH, ACI (CT)	$165,000,000 ($19,000,000)
Meramec 3	FGD, SCR, BH, ACI (CT)	$288,000,000 ($38,000,000)
Meramec 4	FGD, SCR, BH, ACI (CT)	$339,000,000 ($47,000,000)
Rush Island 1	FGD, SCR, BH, ACI (CT)	$515,000,000 ($97,000,000)
Rush Island 2	FGD, SCR, BH, ACI (CT)	$516,000,000 (83,000,000)
Sioux 1	SCR, BH, ACI (CT)	$201,000,000 ($64,000,000)
Sioux 2	SCR, BH, ACI (CT)	$200,000,000 ($65,000,000)
Total		$4,388,000,000 ($825,000,000)

Empire		
Asbury 1	FGD, BH, ACI	$183,000,000
Total		$183,000,000

KCPL/GMO		
Hawthorn 5	ACI (CT)	$4,000,000 ($45,000,000)
Iatan 1	(CT)	($70,000,000)
Lake Road 6/4	FGD, SCR, BH, ACI (CT)	$167,000,000 ($12,000,000)
Montrose 1	FGD, SCR, BH, ACI (CT)	$220,000,000 ($1,000,000)[7]
Montrose 2	FGD, SCR, BH, ACI (CT)	$220,000,000 ($1,000,000)
Montrose 3	FGD, SCR, BH, ACI (CT)	$220,000,000 ($1,000,000)
Sibley 1	FGD, SCR, BH, ACI (CT)	$85,000,000 ($8,000,000)

[6] Costs are in 2009 dollars. Not all generating units utilized by Missouri investor-owned utilities were included in the Sierra Club tables.
[7] Cooling tower estimates for Montrose units did not appear to be correct (in the Sierra Club tables) relative to the other units.

Sibley 2	FGD, SCR, BH, ACI (CT)	$80,000,000 ($7,000,000)
Sibley 3	FGD, BH, ACI (CT)	$292,000,000 ($47,000,000)
Total		$1,288,000,000 ($192,000,000)
TOTALS		$5,859,000,000 ($1,017,000,000)

OTHER INFORMATION SOURCES

The American Public Power Association (APPA) submitted comments to the FERC on March 30, 2012 regarding Coordination between Natural Gas and Electricity Markets.[8] One of the specific points raised in the APPA comments to FERC follows:

> *APPA explains how several Environmental Protection Agency ("EPA") regulations are forcing the retirement of a significant amount of coal and oil-fired generation and increased usage of natural gas to generate electricity. APPA strongly encourages the Commission to review the findings of APPA's own natural gas study, which examines the impacts of increased use of natural gas for electric generation.*

The APPA natural gas study referred to in the preceding quote was conducted by Aspen Environmental Group (Aspen) and published in July 2010[9]. The study reviews natural gas demand, supply, delivery infrastructure, storage, and operational considerations. One significant change in the industry since the publication of this study would be the production of shale gas in various U.S. locations. The last section (except for the conclusion) in the Aspen report is titled "Retrofitting Coal Plants to Burn Natural Gas" and provides information related to the topic of this report. The study challenges the concept of "fuel switching" for coal-fired generating units. Based on information reviewed for the study, it appears that in many cases, "fuel switching" is actually permanent shutdown of a coal-fired generating unit and construction of a new, natural gas-fired combined-cycle generating unit. Note: "fuel switching" can actually occur at some generating units that are configured to utilize alternate fuel sources during normal operation.

Other issues raised by the Aspen study include natural gas transmission/distribution infrastructure relative to supplying large quantities of natural gas fuel for electric generating units. While a significant amount of the U.S. electrical generation is fueled by natural gas (approximately 24% in 2010), as mentioned earlier in this report, Missouri natural gas-fueled generation was only 5.1% for 2010. To shift Missouri's electrical generation significantly towards increased utilization of natural gas fuel, existing generating units would be required to operate at higher capacity factors or new units would need to be constructed. Some generating units could "fuel switch" if properly configured. With some exceptions,

[8] FERC Docket No. AD12-12-000.
[9] http://www.publicpower.org/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf

the majority of the natural gas-fueled generating units that are utilized by Missouri investor-owned electric utilities are designed for intermediate or peaking use. Operation at higher capacity factors could result in higher operating and maintenance costs, resulting in an increased overall cost per megawatt-hour. In some cases, these units may not have adequate firm natural gas transmission capacity to support the increased utilization.

The Aspen study estimates the bounding cost of replacing all U.S. coal-fired generating units with natural gas-fired units at approximately $335 billion. Other costs to implement this "fuel switch", including natural gas pipeline infrastructure, new natural gas gathering facilities, and new underground storage, would be approximately $408 billion for a total of $743 billion. Missouri electric service providers could bear a disproportionate share (3.81% based on a 2010 capacity basis) of this estimate due to the current heavy dependence on coal-fired generation. A significant point to note in the Aspen study is that the costs associated with the upgrades to natural gas infrastructure exceed the actual generating plant replacement costs. Even though differing opinions may exist concerning the magnitude of the cost estimates, the result that the natural gas infrastructure costs exceed the generating unit replacement costs on a relative basis is significant.

Fuel switching or replacing existing coal-fired generating units would not eliminate all capital expenditures associated with future environmental regulations. For instance, new combined cycle generating units may require installation of cooling towers. The size of the cooling towers associated with a combined cycle generating unit would be smaller than a comparable sized coal-fired unit since a significant portion of the combined cycle generating capacity is not a steam unit.

For additional illustration, if Ameren Missouri's Rush Island Energy Center (two 621 MW generating units) were replaced by combined cycle natural gas-fired generating units, the amount of natural gas consumed annually would be approximately 63% of Laclede Gas Company's annual retail natural gas sales. Rush Island generated approximately 19.5% of Ameren Missouri's retail electric sales for 2010. This illustrates the point made in the earlier paragraphs concerning natural gas infrastructure upgrades. Supplying sufficient natural gas for this generating station to operate as a combined-cycle generating station could be a significant concern with existing natural gas infrastructure.

MISO also commissioned a report titled "Gas and Electric Infrastructure Interdependency Analysis" prepared by Gregory L. Peters.[10] This report is dated February 22, 2012 and contains detailed information regarding the existing pipeline infrastructure in the MISO region. Some of the summary points in this report include:

[10] Gregory L. Peters, Principal Consultant, dba EnVision Energy Solutions, for MISO

- Natural gas flow patterns have seen significant changes recently
- Natural gas prices and price volatility has decreased due to oversupply
- Pipeline capacity is a constraint in natural gas shale basins
- Pipeline project sponsors are seeking long-term contracts for natural gas transportation
- Local gas distribution companies are utilizing short-term contracts
- Individual pipeline capacity in MISO varies from no available capacity to available capacity
- The MISO region is at the "crossroads" of the North American natural gas market and could see some flow reversals relative to traditional flows
- Increasing natural gas and electric infrastructure interdependency will require improved collaboration between pipelines, power generators, and regulators

SPP completed an additional assessment following the workshops in this Case. The Reliability Impact Assessment was different from the previous study. In the earlier study, EPA models were used. The recent study used information provided by SPP members' generation plans and outage expectations. While the recent study did not show the same reliability concerns as the first study, outage coordination concerns do exist during the 2013 to 2015 timeframe. SPP will be evaluating an EPA outage coordination study.

UTILITY/CORPORATE 10-K INFORMATION

Companies annually file the "Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934" (a/k/a Form 10-K). For the electric utilities, those reports were filed in February. The 10-K Reports were reviewed for pertinent information. Excerpts and paraphrased portions of that information are included in Appendices A through C, identified by the filing company. Some information is repetitive or not specifically applicable to THE Missouri jurisdiction, but is included for completeness.

From the information provided in the utility/corporate 10-K reports, the environmental-related capital expenditure estimates are provided below. These estimates involve different time frames, dependent on the utility. All of the utilities noted that uncertainty exists regarding potential regulations associated with water intake structures (impingement and entrainment), thermal discharges, and coal combustion residuals. This uncertainty could result in financial and operational consequences for a number of generating units.

Ameren Missouri: $1,225,000,000 to $1,485,000,000 from 2012 through 2021

Great Plains Energy (Missouri jurisdictional[11]): $644,000,000 from 2012 through 2017

Empire District Electric: $112,000,000 to $130,000,000 from 2012 through 2015

Total: $1,981,000,000 to $2,259,000,000 from 2012 through 2021

2012 ELECTRIC UTILITY RESOURCE PLANNING TRIENNIAL COMPLIANCE FILING AND ANNUAL UPDATE REPORTS

In accordance with 4 CSR 240-22.080, Filing Schedule, Filing Requirements, and Stakeholder Process (Electric Utility Resource Planning), Ameren Missouri and Empire submitted an annual update report and KCP&L and GMO submitted triennial compliance filings in 2012. These submittals were reviewed for information pertinent to this investigation. Summary information, as submitted by the utilities, from these plans is provided below.

Ameren Missouri

Ameren Missouri's annual update included a section titled Environmental Compliance Analysis. Primary consideration was given to CSAPR compliance. Existing measures provide SO_2 compliance through 2017. Installation of a flue gas FGD system at Rush Island was included as an option. Also, continued use of ultra-low sulfur coal and conversion of Meramec Plant to natural gas were evaluated. Retirement of the Meramec Plant was evaluated in combination with four supply side resource types: simple cycle gas turbines, combined cycle gas turbines, nuclear (small modular reactor), and wind coupled with simple cycle gas turbines. Compliance with the MATS rule includes electrostatic precipitator upgrades and ACI. Complete details for the annual update are in File No. EO-2012-0357.

Empire

Empire is proceeding with its compliance plan to install a scrubber, fabric filter, and power activated carbon injection at the Asbury Plant (collectively referred to as the Asbury air-quality control system or AQCS). The installation should be completed by early 2015. The estimated cost is $112 million to $130 million. Upon the completion of the AQCS, Asbury Unit 2 will be retired. The compliance plan also includes transitioning Riverton 7 and 8 from coal to natural gas. These units are equipped to utilize either fuel, thus no appreciable capital expense is involved. By 2016, Riverton 12 may be converted from a simple cycle combustion turbine (142 MW) to a combined cycle unit (250 MW). Upon completion of this conversion, Riverton 7 and 8 (and 9) would be retired. Cost information was not provided in the Annual Update Report; however, cost information was provided in the last triennial filing

[11] Based on 10-K Report information and estimated for Missouri jurisdictional impact.

(September 2010). The estimated capital cost (2010 dollars) for the conversion was $1,253/kW or approximately $125,300,000. Complete details for the annual update are in File No. EO-2012-0294.

KCP&L and GMO

KCP&L and GMO triennial filings include preferred plans for the addition of combined cycle, solar, and wind generating units (and noted that solar and wind additions could be obtained from power purchase agreements, purchase of renewable energy credits, or utility ownership). Retirement of three generating units is noted in the preferred plan, Montrose 1 in 2016 (KCP&L) and Sibley 1 and 2 in 2017 (GMO). For all three unit retirements, environmental regulations are noted as the drivers for these decisions. It is also noted that continuing developments regarding these regulations will be monitored to ensure these decisions remain prudent.

KCP&L and GMO both include a document in their filings titled "Narrative Discussion of Environmental Pollutants and Future Changes in Environmental Laws, Regulations, or Standards".[12] This document provides background information and status of regulations for a number of issues related to this report. Complete details for the triennial filings are in File Numbers EO-2012-0323 and EO-2012-0324 for KCP&L and GMO, respectively.

CONCLUSIONS

The current and pending EPA regulations have the potential to significantly impact the electrical generating capacity of Missouri. This report primarily focuses on the coal-fired generating units that serve the Missouri customers of investor-owned utilities. Appendix D lists those coal-fired generating units. Other generating units such as natural gas-fired and nuclear may be impacted by these regulations to a lesser extent and are not addressed in this report.

Control technologies are mature for some types of emissions and evolving for other types. From most perspectives, the two newest generating units (Iatan 2 and Plum Point 1) will not require extensive retrofits, if any. Iatan 1 and Hawthorne 5 generating units have retrofits in place that will satisfy most of the air emissions regulations. The remaining generating units may require extensive capital improvements as well as increased operating and maintenance expenses. Additionally, some emissions control modifications consume significant amounts of electrical power, thus reducing the generating unit's net output.

[12] Identified as Appendix 4E in KCPL filing (File No. EO-2012-0323) and 4H in GMO filing (File No. EO-2012-0324).

For the purposes of this report, existing electric utility resource planning information was reviewed. This information is on record in various cases at the Commission. This is the prescribed process for the Missouri investor-owned electric utilities to document their long-range planning processes. This report is not intended to replace or supersede any of the information that has been provided in these cases (or future cases). There may be opportunities for the electric utilities to minimize the costs associated with new environmental regulations other than upgrades to existing generating units or replacement of existing generating units. Energy efficiency, demand-side management, introduction of distributed generation technology, and other developments may decrease the overall system demand for electricity and thus partially negate the need for additional or existing generating unit(s). Again, the evaluations to support the analysis for decreased demand is reviewed as part of the electric utility resource planning process and should be addressed in that context. Increasing environmental compliance costs will continue to exert pressure on utilities to consider retirement of coal and oil plants. Additionally, the expense of retrofitting a plant to achieve compliance should always be weighed against other options – particularly given that future environmental regulations could be even more stringent and make a retrofit obsolete before recovery of the investment. To assure reliable service at reasonable rates, utilities should consider all available options.

Various studies have been conducted to evaluate the impact of the current and pending EPA rules. While these studies reach different conclusions and results, concerns about overall system reliability due to lack of generation due to retirements appear to be less significant than concerns about outage coordination. Outages may be required for decreased dispatch of existing generating units, retrofits, fuel switching, or environmental upgrades. These outages when occurring simultaneously could impact electrical systems. SPP and MISO continue to evaluate these outage scheduling concerns.

For the purposes of this report, estimated costs of compliance for known EPA regulations were taken from the company/corporate SEC filings. As stated in the "Utility 10-K Information" section of this report those costs were $1,981,000,000 to $2,259,000,000 from 2012 through 2021. For proposed or anticipated regulations, detailed estimates were not provided in the company/corporate 10-K reports. Retrofit of cooling towers to meet possible cooling water regulations could be an additional expense. Since that cost information was not specified in the company/corporate 10-K reports, cost estimates for cooling towers from Sierra Club information would be a total of $1,017,000,000. (Note: The Sierra Club information does not include data for La Cygne 1 and 2 or Jeffrey Energy Center Units 1, 2, and 3. Cooling tower information would only be applicable for La Cygne since Jeffrey Energy Center utilizes cooling towers at present.) Combining the company/corporate 10-K information with the Sierra Club estimates, the range for additional costs due to regulatory compliance would be $1,981,000,000 to $3,276,000,000.

The Sierra Club advocates consideration of alternative sources of generation such as natural gas-fired combustion turbines, natural gas-fired steam plants (or fuel switching to natural gas at existing steam plants), natural gas-fired combined cycle plants, renewable energy (wind), and energy efficiency. The complete analysis is filed in File No. EW-202-0065. These alternatives were reviewed only to the extent that they were included in current utility resource planning results. No cost estimates were developed for these alternatives in this report.

Appendix A

Ameren Missouri

Environmental Matters

We are subject to various environmental laws and regulations enforced by federal, state, and local authorities. From the beginning phases of siting and development to the ongoing operation of existing or new electric generating, transmission and distribution facilities and natural gas storage, transmission and distribution facilities, our activities involve compliance with diverse environmental laws and regulations. These laws and regulations address emissions, impacts to air, land and water, noise, protected natural and cultural resources (such as wetlands, endangered species and other protected wildlife, and archeological and historical resources), and chemical and waste handling. Complex and lengthy processes are required to obtain approvals, permits, or licenses for new, existing or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials (including wastes) requires release prevention plans and emergency response procedures.

In addition to existing laws and regulations, including the Illinois MPS that applies to our energy centers in Illinois, the EPA is developing numerous new environmental regulations that will have a significant impact on the electric utility industry. These regulations could be particularly burdensome for certain companies, including Ameren, Ameren Missouri and Genco, that operate coal−fired energy centers. Significant new rules proposed or promulgated since the beginning of 2010 include the regulation of greenhouse gas emissions; revised national ambient air quality standards for SO2 and NO2 emissions; the CSAPR, which requires further reductions of SO2 and NOx emissions from power plants; a regulation governing management of CCR and coal ash impoundments; the MATS, which requires reduction of emissions of mercury, toxic metals, and acid gases from power plants; revised NSPS for particulate matter, SO2, and NOx emissions from new sources; and new regulations under the Clean Water Act that could require significant capital expenditures such as new water intake structures or cooling towers at our energy centers. The EPA also plans to propose an additional rule, applicable to new and existing electric generating units, governing NSPS and emission guidelines for greenhouse gas emissions. These new regulations may be litigated, so the timing of their implementation is uncertain, as evidenced by the stay of the CSAPR by the United States Court of Appeals for the District of Columbia on December 30, 2011. Although many details of these future regulations are unknown, the combined effects of the new and proposed environmental regulations may result in significant capital expenditures and/or increased operating costs over the next five to ten years for Ameren, Ameren Missouri and Genco. Actions required to ensure that our facilities and operations are in compliance with environmental laws and regulations could be prohibitively expensive. If they are, these regulations could require us to close or to significantly alter the operation of our energy centers, which could have an adverse effect on our results of operations, financial position, and liquidity, including the impairment of plant assets. Failure to comply with environmental laws and regulations might also result in the imposition of fines, penalties, and injunctive measures. The estimates in the table below contain all of the known capital costs to comply with existing environmental regulations and our assessment of the potential impacts of the EPA's proposed regulation for CCR, the recently finalized MATS, the stayed CSAPR as currently designed, and the revised national ambient air quality standards for SO2 and NOx emissions as of December 31, 2011. The estimates in the table below assume that CCR will continue to be regarded as nonhazardous. The estimates in the table below do not include the impacts of new regulations proposed by the EPA under the Clean Water Act in March 2011 regarding cooling water intake structures as our evaluation of those impacts is ongoing. The estimates shown in the table below could change significantly depending upon a variety of factors including:

- additional federal or state requirements;
- regulation of greenhouse gas emissions;
- new national ambient air quality standards or changes to existing standards for ozone, fine particulates, SO2, and NOx emissions;
- additional rules governing air pollutant transport;
- finalized regulations under the Clean Water Act;
- CCR being classified as hazardous;
- whether the CSAPR is implemented and whether any modifications are made to its existing requirements;
- new technology;
- expected power prices;
- variations in costs of material or labor; and
- alternative compliance strategies or investment decisions.

2012	2013 – 2016	2017 – 2021	Total
$55,000,000	$325,000,000 - $400,000,000	$845,000,000 - $1,030,000,000	$1,225,000,000 - $1,485,000,000

The following sections describe the more significant environmental rules that affect our operations.

Clean Air Act

Both federal and state laws require significant reductions in SO2 and NOx emissions that result from burning fossil fuels. In March 2005, the EPA issued regulations with respect to SO2 and NOx emissions (the CAIR). The CAIR required generating facilities in 28 states, including Missouri and Illinois, and the District of Columbia to participate in cap−and−trade programs to reduce annual SO2 emissions, annual NOx emissions, and ozone season NOx emissions.

In December 2008, the United States Court of Appeals for the District of Columbia remanded the CAIR to the EPA for further action to remedy the rule's flaws, but allowed the CAIR's cap−and−trade programs to remain effective until they are replaced by the EPA. In July 2011, the EPA issued the CSAPR as the CAIR replacement. The CSAPR was to become effective on January 1, 2012, for SO2 and annual NOx reductions and on May 1, 2012, for ozone season NOx reductions. In the CSAPR, the EPA developed federal implementation plans for each state covered by this rule; however, each impacted state can develop its own implementation rule starting as early as 2013. The CSAPR establishes emission allowance budgets for each of the states subject to the regulation, including Missouri and Illinois. With the CSAPR, the EPA abandoned CAIR's regional approach to cutting emissions and instead set a pollution budget for each of the impacted states based on the EPA's analysis of each upwind state's contribution to air quality in downwind states. For Missouri and Illinois, emission reductions were required in two phases beginning in 2012, with further reductions in 2014. With the CSAPR, the EPA adopted a cap−and−trade approach that allows intrastate and limited interstate trading of emission allowances with other sources within the same program, that is, in the SO2 program, in the annual NOx, or in ozone season NOx program. Multiple legal challenges were filed requesting to have CSAPR partially or entirely vacated and to stay the implementation of the CSAPR while the court considers the challenges. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued a stay of the CSAPR. The stay does not invalidate the rule, but only delays its implementation until a final court ruling is issued. The United States Court of Appeals for the District of Columbia has expedited its consideration of the regulation and will hear arguments on the validity of CSAPR in April 2012. The ultimate outcome of the challenges to the regulation is uncertain. The court could uphold CSAPR or remand it back to the EPA for partial or entire revision. Until the CSAPR appeal process is concluded, the EPA will continue to administer the CAIR.

On December 21, 2011, the EPA issued the final MATS under the Clean Air Act, which require emission reductions for mercury and other hazardous air pollutants, such as acid gases, toxic metals, and particulate matter by setting emission limits equal to the average emissions of the best performing 12% of existing coal and oil−fired electric generating units. Also, the rule requires reductions in hydrogen chloride emissions, which were not regulated previously, and it may require continuous monitoring systems that are not currently in place. The MATS do not require a specific control technology to achieve the emission reductions. The MATS will apply to each unit at a coal−fired power plant; however, emission compliance can be averaged for the entire power plant. Compliance is required by April 2015 or, with a case−by−case extension, by April 2016.

Separately, in January and June 2010, the EPA finalized new ambient air quality standards for SO2 and NO2. It also announced plans for further reductions in the annual national ambient air quality standards for ozone and fine particulates. The state of Illinois and the state of Missouri will be required to develop separate attainment plans to comply with the new ambient air quality standards. Ameren, Ameren Missouri and Genco continue to assess the impacts of these new standards. In September 2011, the EPA withdrew its draft annual national ambient air quality standard for ozone and announced that it was implementing the 2008 national ambient air quality standard for ozone. The EPA is required to revisit this standard again in 2013.

Ameren Missouri's current environmental compliance plan for air emissions from its energy centers includes burning ultra−low−sulfur coal and installing new or optimizing existing pollution control equipment. In July 2011, Ameren Missouri contracted to procure significantly higher volumes of lower−sulfur−content coal than Ameren Missouri's energy centers have historically burned, which will allow Ameren Missouri to eliminate or postpone capital expenditures for pollution control equipment while still achieving required emissions levels. In 2010, Ameren Missouri completed the installation of two scrubbers at its Sioux energy center to reduce SO2 emissions. Currently, Ameren Missouri's compliance plan assumes the installation of two scrubbers within its coal−fired fleet during the next 10 years and precipitator upgrades at multiple energy centers. However, Ameren Missouri is currently evaluating its operations and options to determine how to comply with the additional emission reductions requirements in 2014 set forth in the CSAPR, if ultimately enacted, the MATS, and other recently finalized or proposed EPA regulations.

The completion of Ameren's, Ameren Missouri's and Genco's review of recently finalized environmental regulations and compliance measures could result in significant increases in capital expenditures and operating costs. The compliance costs could be prohibitive at some of our energy centers as the expected return from these investments, at current market prices for energy and capacity, might not justify the required capital expenditures or their continued operation, which could result in the impairment of long−lived assets.

Emission Allowances

The Clean Air Act created marketable commodities called allowances under the acid rain program, the NOx budget trading program, the CAIR, and the CSAPR. With the CSAPR, the EPA adopted a cap−and−trade approach that allows intrastate and limited interstate trading of emission allowances with other sources within the same program, that is, either the SO2, annual NOx, or ozone season NOx programs. As noted above, on December 30, 2011, the United States Court of Appeals for the District of Columbia issued a stay of the CSAPR. Until the CSAPR appeal process is concluded, the EPA will continue to administer the CAIR including its allowance program. See Note 1 – Summary of Significant Accounting Policies for the SO2 and NOx emission allowance book values that were classified as intangible assets as of December 31, 2011 and 2010, and Note 17 – Goodwill, Impairment and Other Charges for information regarding the emission allowance impairments recorded during 2011 and 2010.

Environmental regulations including the CAIR and the CSAPR, the timing of the installation of pollution control equipment, fuel mix, and the level of operations, will have a significant impact on the number of allowances required for ongoing operations. The CAIR uses the acid rain program's allowances for SO2 emissions and created annual and ozone season NOx allowances. The CSAPR, however, will not rely upon the acid rain program, the NOx budget trading program, or CAIR allowances for its allowance allocation program. Instead, the EPA issued a new type of emissions allowance for each program under the CSAPR. Any unused SO2 allowances, annual NOx allowances, and ozone season NOx allowances issued under CAIR cannot be used for compliance with CSAPR. Ameren, Ameren Missouri and Genco expect to have adequate CAIR allowances for 2012 to avoid needing to make external purchases.

Should the CSAPR become effective as issued, Ameren, Ameren Missouri and Genco are studying their compliance options to identify additional opportunities that may exist for compliance in an economical fashion. Ameren, Ameren Missouri and Genco may be required to purchase emission allowances, if available, to install new or optimize existing pollution control equipment, to limit generation, or take other actions to achieve compliance with the CSAPR in future phase−in years.

Global Climate Change

State and federal authorities, including the United States Congress, have considered initiatives to limit greenhouse gas emissions and to address global climate change. Potential impacts from any climate change legislation or regulation could vary, depending upon proposed CO2 emission limits, the timing of implementation of those limits, the method of distributing any allowances, the degree to which offsets are allowed and available, and provisions for cost−containment measures, such as a "safety valve" provision that provides a maximum price for emission allowances. As a result of our diverse fuel portfolio, our emissions of greenhouse gases vary amongour energy centers, but coal−fired power plants are significant sources of CO2. The enactment of a climate change law could result in a significant rise in household costs and rates for electricity could rise significantly. The burden could fall particularly hard on electricity consumers and upon the economy in the Midwest because of the region's reliance on electricity generated by coal−fired power plants. Natural gas emits about half as much CO 2 as coal when burned to produce electricity. Therefore, climate change regulation could cause the conversion of coal−fired power plants to natural gas, or the construction of new natural gas plants to replace coal−fired power plants. As a result, economywide shifts to natural gas as a fuel source for electricity generation also could affect the cost of heating for our utility customers and many industrial processes that use natural gas.

In December 2009, the EPA issued its "endangerment finding" under the Clean Air Act which stated that greenhouse gas emissions, including CO2, endanger human health and welfare and that emissions of greenhouse gases from motor vehicles contribute to that endangerment. In March 2010, the EPA issued a determination that greenhouse gas emissions from stationary sources, such as power plants, would be subject to regulation under the Clean Air Act effective the beginning of 2011. As a result of these actions, we are required to consider the emissions of greenhouse gases in any air permit application.

Recognizing the difficulties presented by regulating at once virtually all emitters of greenhouse gases, the EPA finalized in May 2010 regulations, known as the "Tailoring Rule," that established new higher thresholds for regulating greenhouse gas emissions from stationary sources, such as power plants. The Tailoring Rule became effective in January 2011. The rule requires any source that already has an operating permit to have greenhouse−gas−specific provisions added to its permits upon renewal. Currently, all Ameren energy centers have operating permits that, when renewed, may be modified to address greenhouse gas emissions. The Tailoring Rule also provides that if projects performed at major sources result in an increase in emissions of greenhouse gases of at least 75,000 tons per year, measured in CO2 equivalents, such projects could trigger permitting requirements under the NSR programs and the application of best available control technology, if any, to control greenhouse gas emissions. New major sources are also required to obtain such a permit and to install the best available control technology if their greenhouse gas emissions exceed the applicable emissions threshold. Separately, in December 2010, the EPA announced a settlement agreement under which it would propose NSPS for greenhouse gas emissions at new and existing fossil fuel−fired power plants by July 26, 2011 and issue a final standard by May 2012. The EPA has not yet proposed a rule and has not specified a new estimate of when it will issue that standard. It is uncertain whether reductions to greenhouse gas emissions would be required at Ameren's, Ameren Missouri's or Genco's energy centers as a result of any of the EPA's new and future rules. Legal challenges to the EPA's greenhouse gas rules have been filed. Any federal climate change legislation that is enacted may preempt the EPA's regulation of greenhouse gas emissions, including the Tailoring Rule, particularly as it relates to power plant greenhouse gas emissions. The extent to which the Tailoring Rule could have a material impact on our energy centers depends upon how state agencies apply the EPA's guidelines as to what constitutes the best available control technology for greenhouse gas emissions from power plants and whether physical changes or changes in operations subject to the rule occur at our energy centers. Although the EPA has stated its intention to regulate greenhouse gas emissions from stationary sources, such as power plants, congressional action could block or delay that effort.

Future federal and state legislation or regulations that mandate limits on the emission of greenhouse gases would likely result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Moreover, to the extent Ameren Missouri requests recovery of these costs through rates, its regulators might delay or deny timely recovery of these costs. Excessive costs to comply with future legislation or regulations might force Ameren, Ameren Missouri and Genco as well as other similarly situated electric power generators to close some coal−fired facilities earlier than planned, which could lead to possible impairment of assets and reduced revenues. As a result, mandatory limits could have a material adverse impact on Ameren's, Ameren Missouri's, and Genco's results of operations, financial position, and liquidity.

Recent federal court decisions have considered the application of common law causes of action, such as nuisance, to address damages resulting from global climate change. In June 2011, the United States Supreme Court in *State of Connecticut v. American Electric Power* rejected state efforts to impose liability for CO 2 and greenhouse gases emissions under federal common law. That ruling, however, did not address whether private citizens could pursue causes of action based on state common law. In June 2011, a case called Comer v. Murphy Oil (Comer) was filed in the United States District Court for the Southern District of Mississippi. In this litigation, a Mississippi property owner sued several industrial companies, including Ameren Missouri and Genco, alleging that CO2 emissions created the atmospheric conditions that intensified Hurricane Katrina. Although we are unable to predict the outcome of the Comer litigation on our results of operations, financial position, and liquidity, Ameren believes that it has meritorious defenses. Numerous procedural and substantive challenges are expected in the Comer litigation.

The impact on us of future initiatives related to greenhouse gas emissions and global climate change is unknown. Compliance costs could increase as future federal legislative, federal regulatory, and state−sponsored initiatives to control greenhouse gases continue to progress, making it more likely that some form of greenhouse gas emissions control will eventually be required. Since these initiatives continue to evolve, the impact on our coal−fired energy centers and our customers' costs is unknown, but any impact would probably be negative. Our costs of complying with any mandated federal or state greenhouse gas program could have a material impact on our future results of operations, financial position, and liquidity.

NSR and Clean Air Litigation

The EPA is engaged in an enforcement initiative to determine whether coal−fired power plants failed to comply with the requirements of the NSR and NSPS provisions under the Clean Air Act when the plants implemented modifications. The EPA's inquiries focus on whether projects performed at power plants should have triggered various permitting requirements and the installation of pollution control equipment.

Following the issuance of a Notice of Violation, in January 2011, the Department of Justice on behalf of the EPA filed a complaint against Ameren Missouri in the United States District Court for the Eastern District of Missouri. The EPA's complaint alleges that in performing projects at its Rush Island coal−fired energy center, Ameren Missouri violated provisions of the Clean Air Act and Missouri law. In January 2012, the United States District Court granted, in part, Ameren Missouri's motion to dismiss various aspects of the EPA's penalty claims. The EPA's claims for injunctive relief, including to require the installation of pollution control equipment, remain. At present, the complaint does not include Ameren Missouri's other coal−fired energy centers, but the EPA has issued Notices of Violation under its NSR enforcement initiative against the company's Labadie, Meramec, and Sioux coal−fired energy centers. Litigation of this matter could take many years to resolve. Ameren Missouri believes its defenses to the allegations described in the complaint as well as the Notices of Violation are meritorious. Ameren Missouri will defend itself vigorously. However, there can be no assurances that it will be successful in its efforts.

Ultimate resolution of these matters could have a material adverse impact on the future results of operations, financial position, and liquidity of Ameren, Ameren Missouri and Genco. A resolution could result in increased capital expenditures for the installation of pollution control equipment, increased operations and maintenance expenses, and penalties. We are unable to predict the ultimate resolution of these matters or the costs that might be incurred. However, Ameren Missouri has concluded that, while a loss may be reasonably possible, the likelihood of loss is not probable. Therefore, no reserve has been established.

Clean Water Act

In March 2011, the EPA announced a proposed rule applicable to cooling water intake structures at existing power plants that have the ability to withdraw more than 2 million gallons of water per day from a body of water and use at least 25 percent of that water exclusively for cooling. Under the proposed rule, affected facilities would be required either to meet mortality limits for aquatic life impinged on the plant's intake screens or to reduce intake velocity to 0.5 feet per second. The proposed rule also requires plants to meet site−specific entrainment standards or to reduce the cooling water intake flow commensurate with the intake flow of a closed−cycle cooling system. The final rule is scheduled to be issued in July 2012, with compliance expected within eight years thereafter. All coal−fired, nuclear, and combined cycle energy centers at Ameren, Ameren Missouri and Genco with cooling water systems are subject to this proposed rule. The proposed rule did not mandate cooling towers at existing facilities, as other technology options potentially could meet the site−specific standards. Ameren, Ameren Missouri and Genco are currently evaluating the proposed rule, and their assessment of the proposed rule's impacts is ongoing. Therefore, we cannot predict at this time the capital or operating costs associated with compliance. The proposed rule could have an adverse effect on our results of operations, financial position, and liquidity if its implementation requires the installation of cooling towers at our electric generating stations.

In September 2009, the EPA announced its plan to revise the effluent guidelines applicable to steam electric generating units under the Clean Water Act. Effluent guidelines are national standards for wastewater discharges to surface water that are based on the effectiveness of available control technology. The EPA is engaged in information collection and analysis activities in support of this rulemaking. It has indicated that it expects to issue a proposed rule in July 2012 and to finalize the rule in 2014. We are unable at this time to predict the impact of this development.

Ash Management

There has been activity at both state and federal levels regarding additional regulation of ash pond facilities and CCR. In

May 2010, the EPA announced proposed new regulations regarding the regulatory framework for the management and disposal of CCR, which could affect future disposal and handling costs at our energy centers. Those proposed regulations include two options for managing CCRs under either solid or hazardous waste regulations, but either alternative would allow for some continued beneficial uses, such as recycling of CCR without classifying it as waste. As part of its proposal, the EPA is considering alternative regulatory approaches that require coal−fired power plants either to close surface impoundments, such as ash ponds, or to retrofit such facilities with liners. Existing impoundments and landfills used for the disposal of CCR would be subject to groundwater monitoring requirements and requirements related to closure and postclosure care under the proposed regulations. Additionally, in January 2010, EPA announced its intent to develop regulations establishing financial responsibility requirements for the electric generation industry, among other industries, and it specifically discussed CCR as a reason for developing the new requirements. Ameren, Ameren Missouri and Genco are currently evaluating all of the proposed regulations to determine whether current management of CCR, including beneficial reuse, and the use of the ash ponds should be altered. Ameren, Ameren Missouri and Genco also are evaluating the potential costs associated with compliance with the proposed regulation of CCR impoundments and landfills, which could be material, if such regulations are adopted.
In addition, the Illinois EPA requested that Ameren, Ameren Missouri and Genco establish groundwater monitoring plans for their ash impoundments in Illinois. Ameren and the Illinois EPA have established a framework for closure of ash ponds in Illinois, including the ash ponds at Venice, Hutsonville, and Duck Creek, when such facilities are ultimately taken out of service. Ameren, Ameren Missouri and Genco have recorded AROs, based on current laws, for the estimated costs of the retirement of their ash ponds.

Appendix B

Great Plains Energy and Kansas City Power & Light Company

Environmental Matters

Great Plains Energy and KCP&L are subject to extensive federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and disposal, natural resources and health and safety. In addition to imposing continuing compliance obligations and remediation costs, these laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is expected to be material to Great Plains Energy and KCP&L. Failure to comply with environmental requirements or to timely recover environmental costs through rates could have a material effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.
The following discussion groups environmental and certain associated matters into the broad categories of air and climate change, water, solid waste and remediation.

Air and Climate Change Overview
The Clean Air Act and associated regulations enacted by the Environmental Protection Agency (EPA) form a comprehensive program to preserve air quality. States are required to establish regulations and programs to address all requirements of the Clean Air Act and have the flexibility to enact more stringent requirements. All of Great Plains Energy's and KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Air Act. Great Plains Energy's and KCP&L's current estimate of capital expenditures (exclusive of AFUDC and property taxes) to comply with the currently-effective Clean Air Interstate Rule (CAIR), the replacement to CAIR or the Cross-State Air Pollution Rule (CSAPR), the best available retrofit technology (BART) rule, the SO2 National Ambient Air Quality Standard (NAAQS), the industrial boiler rule and the Mercury and Air Toxics Standards (MATS) rule that would reduce emissions of toxic air pollutants, (all of which are discussed below) is approximately $1 billion. The actual cost of compliance with any existing, proposed or future rules may be significantly different from the cost estimate provided.
The approximate $1 billion current estimate of capital expenditures reflects the following capital projects:

- KCP&L's La Cygne No. 1 scrubber and baghouse installed by June 2015;
- KCP&L's La Cygne No. 2 full air quality control system (AQCS) installed by June 2015;
- KCP&L's Montrose No. 3 full AQCS installed by approximately 2017; and
- GMO's Sibley No. 3 scrubber and baghouse installed by approximately 2017.

In September 2011, KCP&L commenced construction of the La Cygne project. Other capital projects at KCP&L's Montrose Nos. 1 and 2 and GMO's Sibley Nos. 1 and 2 and Lake Road Nos. 4 and 6 are possible but are currently considered less likely. Any capacity and energy requirements resulting from a decision not to proceed with these less likely projects is currently expected to be met through renewable energy additions required under Missouri and Kansas renewable energy standards, demand side management programs, construction of combustion turbines and/or combined cycle units, and/or power purchase agreements.
The estimate does not reflect the non-capital costs the Companies incur on an ongoing basis to comply with environmental laws, which may increase in the future due to the Companies' ongoing compliance with current or future environmental laws. The Companies expect to seek recovery of the costs associated with environmental requirements through rate increases; however, there can be no assurance that such rate increases would be granted. The Companies may be subject to materially adverse rate treatment in response to competitive, economic, political, legislative or regulatory pressures and/or public perception of the Companies' environmental reputation.

Clean Air Interstate Rule (CAIR) and Cross-State Air Pollution Rule (CSAPR)
The CAIR requires reductions in SO2 and NOx emissions in 28 states, including Missouri. The reductions in SO2 and NOx emissions are accomplished through statewide caps for NOx and SO2. Great Plains Energy's and KCP&L's fossil fuel-fired plants located in Missouri are subject to CAIR, while their fossil fuel-fired plants in Kansas are not.
On July 11, 2008, the D.C. Circuit Court of Appeals vacated CAIR in its entirety and remanded the matter to the EPA to promulgate a new rule consistent with its opinion. On December 23, 2008, the Court issued an order remanding CAIR to the EPA to revise the rule consistent with its July 2008 order.
In July 2011, the EPA finalized the CSAPR to replace the currently-effective CAIR. The CSAPR requires the states within its scope to reduce power plant SO2 and NOx emissions that contribute to ozone and fine particle nonattainment in other states. The geographical scope of the CSAPR includes Kansas, Missouri and other states. Kansas and Missouri are included in the annual SO2 and NOx programs for the control of fine particulate matter in the CSAPR. In December 2011, the EPA finalized a rulemaking to include Missouri for ozone season control but not Kansas. The EPA will address the inclusion of Kansas in a separate action and revisit Kansas' status in the CSAPR at that time. In the CSAPR, the EPA set an emissions budget for each of the affected states. The CSAPR allows limited interstate emissions allowance trading among power plants; however, it does not permit trading of SO2 allowances between the Companies' Kansas and Missouri power plants. There would be additional reductions in SO2 allowances allocable to the Companies' Missouri power plants taking effect in 2014. There is no such 2014

additional reduction in SO2 allowances allocable to the Companies' Kansas power plants. In February 2012, the EPA finalized technical adjustments to the final CSAPR. The rules amend the assurance penalty provisions, which would further restrict interstate trading of emission allowances, to start in 2014 instead of 2012. The EPA revised certain unit-level allocations in certain states, including Kansas and Missouri, which would re-allocate allowances to assist KCP&L in compliance with the CSAPR.

Compliance with the CSAPR was to begin in 2012. Multiple states, utilities and other parties, including KCP&L, filed requests for reconsideration and stays with the EPA and/or the D.C. Circuit Court. In December 2011, the D.C. Circuit Court issued an order staying the CSAPR pending the Court's resolution of the petitions for review of the rule. The order requires the EPA to continue administering the CAIR while the CSAPR is stayed.

The CSAPR is complex and Great Plains Energy and KCP&L are evaluating its impacts. The Companies project that they may not be allocated sufficient SO2 or NOX emissions allowances to cover their currently expected operations when the rule becomes effective. Any shortfall in allocated allowances is anticipated to be addressed through a combination of permissible allowance trading, installing additional emission control equipment, changes in plant processes, or purchasing additional power in the wholesale market.

Best Available Retrofit Technology (BART) Rule

The EPA BART rule directs state air quality agencies to identify whether visibility-reducing emissions from sources subject to BART are below limits set by the state or whether retrofit measures are needed to reduce emissions. BART applies to specific eligible facilities including KCP&L's La Cygne Nos. 1 and 2 in Kansas, KCP&L's Iatan No. 1, in which GMO has an 18% interest, KCP&L's Montrose No. 3 in Missouri, GMO's Sibley Unit No. 3 and Lake Road Unit No. 6 in Missouri and Westar Energy, Inc.'s (Westar) Jeffrey Unit Nos. 1 and 2 in Kansas, in which GMO has an 8% interest. Both Missouri and Kansas have submitted BART plans to the EPA. In December 2011, the EPA issued a proposal that would approve the CSAPR as an alternative to determining BART. As a result, states in the CSAPR would be able to substitute participation in the CSAPR for source-specific BART. In December 2011, the EPA approved the Kansas BART plan.

Mercury and Air Toxics Standards (MATS) Rule

In January 2009, the EPA issued a memorandum stating that new electric steam generating units (EGUs) that began construction while the Clean Air Mercury Rule (CAMR) was effective are subject to a new source maximum achievable control technology (MACT) determination on a case-by-case basis. In July 2009, the EPA sent a letter notifying KCP&L that a MACT determination and schedule of compliance is required for coal and oil-fired EGUs that began actual construction or reconstruction after December 15, 2000, and identified Iatan No. 2 as an affected EGU. This was an outcome of the D.C. Circuit Court of Appeals' vacatur of both the CAMR and the contemporaneously promulgated rule removing EGUs from MACT requirements. It is not currently known how the MACT determination and schedule of compliance will impact the permitting or operating requirements for Iatan No. 2, but it is possible a MACT determination may ultimately require additional emission control equipment and permit limits.

In December 2011, the EPA finalized the Mercury and Air Toxics Standards (MATS) Rule that will reduce emissions of toxic air pollutants, also known as hazardous air pollutants, from new and existing coal- and oil-fired EGUs with a capacity of greater than 25 MWs. The rule establishes numerical emission limits for mercury, particulate matter (a surrogate for nonmercury metals), and hydrochloric acid (a surrogate for acid gases). The rule establishes work practices, instead of numerical emission limits, for organic air toxics, including dioxin/furan. Compliance with the rule would need to be addressed by installing additional emission control equipment, changes in plant operation, purchasing additional power in the wholesale market or a combination of these and other alternatives. The rule allows three years for compliance with authority for state permitting authorities to grant an additional year as needed for technology installation. The EPA indicated that it expects this option to be broadly available.

Industrial Boiler Rule

In February 2011, the EPA issued a final rule that would reduce emissions of hazardous air pollutants from new and existing industrial boilers. In May 2011, the EPA announced it would stay the effective date of the final rule during reconsideration; although in January 2012, the D.C. Circuit Court vacated the stay and remanded the stay to the EPA. In December 2011, the EPA issued a proposed revised rule and intends to issue a final rule in the spring of 2012. The proposed revised rule establishes numeric emission limits for mercury, particulate matter (as a surrogate for non-mercury metals), hydrogen chloride (as a surrogate for acid gases), and carbon monoxide (as a surrogate for non-dioxin organic hazardous air pollutants). The final rule establishes emission limits for KCP&L's and GMO's existing units that produce steam other than for the generation of electricity. The existing boiler rule and its proposed revisions do not apply to KCP&L's and GMO's electricity generating boilers, but would apply to most of GMO's Lake Road boilers, which also serve steam customers, and to auxiliary boilers at other generating facilities.

New Source Review

The Clean Air Act requires companies to obtain permits and, if necessary, install control equipment to reduce emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in regulated missions.

In March 2010, the U.S. District Court in the District of Kansas approved a settlement agreement between Westar and the parties of a lawsuit filed by the Department of Justice on behalf of the EPA. The lawsuit asserted that certain projects completed at the

Jeffrey Energy Center violated certain requirements of the EPA's New Source Review program. The Jeffrey Energy Center consists of three coal-fired units located in Kansas that is 92% owned by Westar and operated exclusively by Westar. GMO has an 8% interest in the Jeffrey Energy Center and is generally responsible for its 8% share of the facility's operating costs and capital expenditures. The settlement agreement required, among other things, the installation of a selective catalytic reduction (SCR) system at one of the Jeffrey Energy Center units by the end of 2014 and the payment of a $3 million civil penalty. Westar has estimated the cost of this SCR at approximately $240 million. Depending on the NOx emission reductions attained by that SCR and attainable through the installation of other controls at the other two units, the settlement agreement may require the installation of a second SCR system on one of the other two units by the end of 2016. There is no assurance that GMO's share of these costs would be recovered in rates and failure to recover such costs could have a significant effect on Great Plains Energy's results of operations, financial position and cash flows.

KCP&L has received requests for information from the Kansas Department of Health and Environment (KDHE) pertaining to a past La Cygne No. 1 scrubber project. KCP&L is working with the KDHE to resolve this issue and management currently believes the outcome will not have a significant impact on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Collaboration Agreement

In March 2007, KCP&L, the Sierra Club and the Concerned Citizens of Platte County entered into a Collaboration Agreement under which KCP&L agreed to pursue a set of initiatives including energy efficiency, additional wind generation, lower emission permit levels at its Iatan and La Cygne generating stations and other initiatives designed to offset CO2 emissions. Full implementation of the terms of the Collaboration Agreement will necessitate approval from the appropriate authorities, as some of the initiatives in the agreement require regulatory approval.

In 2006, KCP&L installed 100 MWs of wind generation at its Spearville wind site. KCP&L agreed in the Collaboration Agreement to pursue increasing its wind generation capacity to 500 MWs in total by the end of 2012 with 100 MWs to be added by the end of 2010 and the remainder added by the end of 2012, subject to regulatory approval. In 2010, KCP&L completed a 48 MWs wind project adjacent to its existing Spearville wind site with wind turbines it already owned and also secured 52 MWs of renewable energy credits. During 2011, KCP&L entered into long-term power purchase agreements for approximately 231 MWs of wind generation beginning in 2012 and GMO entered into a long-term power purchase agreement for approximately 100 MWs of wind generation beginning in 2012, which expire in 2032.

KCP&L has a consent agreement with the KDHE incorporating limits for stack particulate matter emissions, as well as limits for NOx and SO2 emissions, at its La Cygne Station that, consistent with the Collaboration Agreement, will be below the presumptive limits under BART. KCP&L further agreed to use its best efforts to install emission control technologies to reduce those emissions from the La Cygne Station prior to the required compliance date under BART, but in no event later than June 1, 2015. In August 2011, KCC issued its order on KCP&L's predetermination request that would apply to the recovery of costs for its 50% share of the environmental equipment required to comply with BART at the La Cygne Station. In the order, KCC stated that KCP&L's decision to retrofit La Cygne was reasonable, reliable, efficient and prudent and the $1.23 billion cost estimate is reasonable. If the cost for the project is at or below the $1.23 billion estimate, absent a showing of fraud or other intentional imprudence, KCC stated that it will not re-evaluate the prudency of the cost of the project. If the cost of the project exceeds the $1.23 billion estimate and KCP&L seeks to recover amounts exceeding the estimate, KCP&L will bear the burden of proving that any additional costs were prudently incurred. KCP&L's 50% share of the estimated cost is $615 million. KCP&L began the project in September 2011.

In the Collaboration Agreement, KCP&L also agreed to offset an additional 711,000 tons of CO2 by the end of 2012. KCP&L currently expects to achieve this offset through a number of alternatives, including improving the efficiency of its coal-fired units, equipping certain gas-fired units for winter operation and, if necessary, possibly reducing output of, or retiring, one or more coal-fired units.

Climate Change

The Companies are subject to existing greenhouse gas reporting regulations and certain greenhouse gas permitting requirements. Management believes it is possible that additional federal or relevant state or local laws or regulations could be enacted to address global climate change. At the international level, while the United States is not a current party to the international Kyoto Protocol, it has agreed to undertake certain voluntary actions under the non-binding Copenhagen Accord and pursuant to subsequent international discussions relating to climate change, including the establishment of a goal to reduce greenhouse gas emissions. International agreements legally binding on the United States may be reached in the future. Such new laws or regulations could mandate new or increased requirements to control or reduce the emission of greenhouse gases, such as CO2, which are created in the combustion of fossil fuels. The Companies' current generation capacity is primarily coal-fired and is estimated to produce about one ton of CO2 per MWh, or approximately 25 million tons and 18 million tons per year for Great Plains Energy and KCP&L, respectively.

Laws have recently been passed in Missouri and Kansas, the states in which the Companies' retail electric businesses are operated, setting renewable energy standards, and management believes that national clean or renewable energy standards are also possible. While management believes additional requirements addressing these matters will probably be enacted, the timing, provisions and impact of such requirements, including the cost to obtain and install new equipment to achieve compliance, cannot be reasonably estimated at this time. In addition, certain federal courts have held that state and local governments and private parties have standing to bring climate change tort suits seeking company-specific emission reductions and monetary or other damages. While the Companies are not a party to any climate change tort suit, there is no assurance that such suits may not be filed in the future or as to the outcome if such suits are filed. Such requirements or litigation outcomes could have the potential for a significant financial and operational impact on Great Plains Energy and KCP&L. The Companies would likely seek recovery of capital costs and expenses for compliance through rate increases; however, there can be no assurance that such rate increases would be granted.

Legislation concerning the reduction of emissions of greenhouse gases, including CO2, is being considered at the federal and state levels. The timing and effects of any such legislation cannot be determined at this time. In the absence of new Congressional mandates, the EPA is proceeding with the regulation of greenhouse gases under the existing Clean Air Act.

In March 2011, the EPA announced it finalized a settlement agreement to issue a rule that will address greenhouse gas emissions from EGUs. The rule would establish new source performance standards for new and modified EGUs and emission guidelines for existing EGUs. Under the settlement agreement, the EPA committed to issuing proposed regulations by September 2011, although the EPA did not meet that date, and final regulations by May 2012.

At the state level, a Kansas law enacted in May 2009 required Kansas public electric utilities, including KCP&L, to have renewable energy generation capacity equal to at least 10% of their three-year average Kansas peak retail demand by 2011. The percentage increases to 15% by 2016 and 20% by 2020. A Missouri law enacted in November 2008 required at least 2% of the electricity provided by Missouri investor-owned utilities (including KCP&L and GMO) to their Missouri retail customers to come from renewable resources, including wind, solar, biomass and hydropower, by 2011, increasing to 5% in 2014, 10% in 2018, and 15% in 2021, with a small portion (estimated to be about 2MW in 2011 for each of KCP&L and GMO) required to come from solar resources.

KCP&L and GMO project that they will be compliant with the Missouri renewable requirements, exclusive of the solar requirement, through 2023 for KCP&L and 2018 for GMO. KCP&L and GMO project that the purchase of solar renewable energy credits will be sufficient for compliance with the Missouri solar requirements for the foreseeable future. KCP&L also projects that it will be compliant with the Kansas renewable requirements through 2016.

Greenhouse gas legislation or regulation has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L, including the potential costs and impacts of achieving compliance with limits that may be established. However, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until such legislation is passed and/or regulations are issued. Management will continue to monitor the progress of relevant legislation and regulations.

SO2 NAAQS

In June 2010, the EPA strengthened the primary NAAQS for SO2. The EPA revised the primary SO2 standard by establishing a new 1-hour standard at a level of 0.075 ppm. The EPA revoked the two existing primary standards of 0.140 ppm evaluated over 24 hours and 0.030 ppm evaluated over an entire year. In July 2011, the MDNR recommended to the EPA that part of Jackson County, Missouri, which is in the Companies' service territory, be designated a nonattainment area for the new 1-hour SO2 standard.

Montrose Station Notice of Violation

In June 2009, KCP&L received notification from the MDNR alleging that its Montrose Station had excess particulate matter emissions in 2008. In November 2011, KCP&L and MDNR Executed an Abatement Order on Consent that resolved all claims for the violations alleged without KCP&L admitting the validity or accuracy of such claims. KCP&L agreed in compromise and satisfaction of MDNR's claims to complete a supplemental environmental project in the amount of $150,000.

Water

The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to preserve water quality. Like the Clean Air Act, states are required to establish regulations and programs to address all requirements of the Clean Water Act, and have the flexibility to enact more stringent requirements. All of Great Plains Energy's and KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Water Act.

In March 2011, the EPA proposed regulations pursuant to Section 316(b) of the Clean Water Act regarding cooling water intake structures pursuant to a court approved settlement. KCP&L generation facilities with cooling water intake structures would be subject to a limit on how many fish can be killed by being pinned against intake screens (impingement) and would be required to conduct studies to determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms drawn into cooling water systems (entrainment). The EPA agreed to finalize the rule by July 2012. Although the impact on Great Plains Energy's and KCP&L's operations will not be known until after the rule is finalized, it could have a significant effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

KCP&L holds a permit from the MDNR covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri river for cooling purposes and return the heated water to the Missouri river. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. KCP&L cannot predict the outcome of this matter; however, while less significant outcomes are possible, this matter may require KCP&L to reduce its generation at Hawthorn Station, install cooling towers or both, any of which could have a significant impact on KCP&L. The outcome could also affect the terms of water permit renewals at KCP&L's Iatan Station and at GMO's Sibley and Lake Road Stations.

Additionally, in September 2009, the EPA announced plans to revise the existing standards for water discharges from coal-fired power plants. In November 2010, the EPA filed a motion requesting court approval of a consent agreement in which the EPA agreed to propose a rule in July 2012 and to finalize it in January 2014. Until a rule is proposed and finalized, the financial and operational impacts to Great Plains Energy and KCP&L cannot be determined.

Solid Waste

Solid and hazardous waste generation, storage, transportation, treatment and disposal is regulated at the federal and state levels under various laws and regulations. In May 2010, the EPA proposed to regulate coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA) to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The EPA is considering two options in this proposal. Under the first option, the EPA would regulate CCRs as special wastes subject to regulation under subtitle C of RCRA (hazardous), when they are destined for disposal in landfills or surface impoundments. Under the second option, the EPA would regulate disposal of CCRs under subtitle D of RCRA (nonhazardous). The Companies principally use coal in generating electricity and dispose of the CCRs in both on-site facilities and facilities owned by third parties. The proposed CCR rule has the potential of having a significant financial and operational impact on Great Plains Energy and KCP&L in connection with achieving compliance with the proposed requirements. However, the financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until an option is selected by the EPA and the final regulation is enacted.

Appendix C

The Empire District Electric Company

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time. We expect this trend to continue. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect any such costs to be material, although recoverable in rates.

Air

The Federal Clean Air Act (CAA) and comparable state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control and related requirements. These requirements include maximum emission limits on our facilities for sulfur dioxide (SO2), particulate matter, and nitrogen oxides (NOx). In the future they are also likely to include limits on emissions of mercury, other hazardous pollutants (HAPs) and so-called greenhouse gases (GHG) such as carbon dioxide (CO2) and methane.

Permits

Under the CAA we have obtained, and renewed as necessary, site operating permits, which are valid for five years, for each of our plants.

Compliance Plan

In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). While the Cross State Air Pollution Rule (CSAPR) that was set to take effect on January 1, 2012 was stayed at the last minute in late December 2011 by the District of Columbia Circuit Court of Appeals, the Mercury and Air Toxics Standards (MATS) Rules were signed by the Environmental Protection Agency (EPA) Administrator on December 16, 2011. MATS is set to become effective and will require compliance within a three year timeframe (with flexibility for extensions for reliability reasons). This Compliance Plan largely follows the preferred plan presented in our most recent Integrated Resource Plan. The Compliance Plan calls for the installation of a scrubber, fabric filter, and powder activated carbon injection system at our Asbury plant by early 2015 at a cost ranging from $112 million to $130 million. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, an 18 megawatt steam turbine that is currently used for peaking purposes. The Compliance Plan also calls for the transition of our Riverton Units 7 and 8 from operation on coal to full operation on natural gas after the summer of 2013. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 for start-up, will be retired upon the conversion of Riverton Unit 12, a recently installed simple cycle combustion turbine, to a combined cycle unit. This conversion is currently scheduled for the 2016 timeframe.

SO2 Emissions

The CAA regulates the amount of SO2 an affected unit can emit. Currently SO2 emissions are regulated by the Title IV Acid Rain Program and the Clean Air Interstate Rule (CAIR). On January 1, 2012, CAIR was to have been replaced by the Cross-State Air Pollution Rule (CSAPR- formerly the Clean Air Transport Rule). But, on December 30, 2011 the District of Columbia Circuit Court of Appeals issued a stay of the CSAPR. CAIR will remain in effect while the case is reviewed. The Title IV Acid Rain Program will still remain in effect.

The Mercury Air Toxics Standards (MATS), discussed below, was signed on December 16, 2011, and will affect SO2 emission rates at our facilities. In addition, the compliance date for the revised SO2 National Ambient Air Quality Standards (NAAQS) is August of 2017; this will also affect SO2 emissions from our facilities. The SO2 NAAQS is discussed in more detail below.

Title IV Acid Rain Program:

Under the Title IV Acid Rain Program, each existing affected unit has been allocated a specific number of emission allowances by the U.S. Environmental Protection Agency (EPA). Each allowance entitles the holder to emit one ton of SO2. Covered utilities, such as Empire, must have emission allowances equal to the number of tons of SO2 emitted during a given year by each of their affected units. Allowances in excess of the annual emissions are banked for future use. In 2010, our SO2 emissions exceeded the annual allocations. This deficit was covered by our banked allowances. When our Title IV Acid Rain Program SO2 allowance bank is exhausted, currently estimated to be late 2012, we will need to purchase additional SO2 allowances, blend more low sulfur coal at our facilities or transition our coal-fired Riverton Units 7 and 8 to natural gas or a combination of the above. Long-term compliance with this program will be met by the Compliance Plan detailed above along with possible procurement of additional S02 allowances. We expect the cost of compliance to be fully recoverable in our rates.

CAIR:

In 2005, the EPA promulgated CAIR under the CAA. CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of SO2 and/or NOx in 28 eastern states and the District of Columbia, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and our Riverton Plant was not affected. Arkansas, where our Plum Point Plant is located, was included for ozone season NOx but not for SO2.

In 2008, the U.S. Court of Appeals for the District of Columbia vacated CAIR and remanded it back to EPA for further consideration, but also stayed its vacatur. As a result, CAIR became effective for NOx on January 1, 2009 and for SO2 on January 1, 2010 and required covered states to develop State Implementation Plans (SIPs) to comply with specific SO2 state-wide annual budgets.

SO2 allowance allocations under the Title IV Acid Rain Program are used for compliance in the CAIR SO2 Program. Beginning in 2010, SO2 allowances were utilized at a 2:1 ratio for our Missouri units. As a result, based on current SO2 allowance usage projections, we expected to have sufficient allowances to take us into the latter part of 2012.

In order to meet CAIR requirements for SO2 and NOx emissions (NOx is discussed below in more detail) and as a requirement for the air permit for Iatan 2, a Selective Catalytic Reduction system (SCR), a FGD scrubber system and baghouse were installed at our jointly-owned Iatan 1 plant and a SCR was installed at our Asbury plant in 2008. Our jointly-owned Iatan 2 and Plum Point plants were originally constructed with the above technology.

CSAPR- formerly the Clean Air Transport Rule:

On July 6, 2010, the EPA published a proposed CAIR replacement rule entitled the Clean Air Transport Rule (CATR). As proposed and supplemented, the CATR included Missouri and Kansas under both the annual and ozone season for NOx as well as the SO2 program while Arkansas remained in the ozone season NOx program only. The final CATR was released on July 7, 2011 under the name of the CSAPR, and was set to become effective January 1, 2012. However, as mentioned above, the District of Columbia Circuit Court of Appeals stayed the rule and as of January 1, 2012, the CAIR will be in effect while the court reviews the case. When it was published, the final CSAPR required a 73% reduction in SO2 from 2005 levels by 2014. The SO2 allowances allocated under the EPA's Title IV Acid Rain Program cannot be used for compliance with CSAPR but would continue to be used for compliance with the Title IV Acid Rain Program. Therefore, new SO2 allowances would be allocated under CSAPR and retired at one allowance per ton of SO2 emissions emitted. We would receive fewer SO2 allowances than we currently emit. Long-term compliance with this Rule will be met by the Compliance Plan detailed above along with possible procurement of additional SO2 allowances. A number of states, including Kansas, electric utilities and industrial organizations commenced litigation with the District of Columbia Court of Appeals challenging the CSAPR being stayed. The court has ordered that the parties submit briefs for an April 2012 hearing. We expect compliance costs to be recoverable in our rates.

Mercury Air Toxics Standard:

Proposed by the EPA on March 16, 2011 and signed on December 16, 2011, the MATS regulation does not include allowance mechanisms, but would establish alternative standards for certain pollutants, including SO2 (as a surrogate for hydrogen chloride (HCI)), which must be met to show compliance with hazardous air pollutant limits (see additional discussion in the MATS section below).

SO2 National Ambient Air Quality Standard (NAAQS):

In June 2010, the EPA finalized a new 1-hour SO2 NAAQS which, for areas with no SO2 monitor, will require modeling to determine attainment and non-attainment areas within each state. This modeling of emission sources is to be completed by June 2013 with compliance with the SO2 NAAQS required by August 2017. Draft guidance for 1-hour SO2 NAAQS has been published by the EPA to assist states as they prepare their SIP submissions. The EPA is also planning a rulemaking to address some of the 1-hour SO2 NAAQS implementation program elements. It is likely coal-fired generating units will need scrubbers to be capable of meeting the new 1-hour SO2 NAAQS. In addition, units will be required to include SO2 emissions limits in their Title V permits or execute consent decrees to assure attainment and future compliance.

NOx Emissions

The CAA regulates the amount of NOx an affected unit can emit. As currently operated, each of our affected units is in compliance with the applicable NOx limits. Currently, revised NOx emissions are limited by the CAIR (subject to the outcome of the CSAPR proceedings) and by ozone NAAQS rules (discussed below) which were established in 1997 and in 2008.

CAIR:

In 2005, the EPA promulgated CAIR under the CAA. CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of NOx in 28 states, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located and Arkansas where the Plum Point Energy Station is located. Kansas was not included in CAIR and our Riverton Plant was not affected.

The CAIR required covered states to develop SIPs to comply with specific annual NOx state-wide allowance allocation budgets. Based on existing SIPs, we had excess NOx allowances during 2010 which were banked for future use and will be sufficient for compliance at least through the end of 2012. The CAIR NOx program also was to have been replaced by the CSAPR program January 1, 2012 but because of the court stay will remain in effect while the case is reviewed.

CSAPR:

As published, the final rule requires a 54% reduction in NOx from 2005 levels by 2014. The NOx annual and ozone season allowances that were allocated and banked under CAIR cannot be used for compliance under CSAPR. New allowances will be issued under CSAPR.

To address NOx annual and NOx ozone season compliance, our options range from increasing the level of control with the Asbury SCR, the transition of our Riverton Plant coal-fired units to natural gas, or purchasing emission allowances. We expect the cost of compliance to be fully recoverable in our rates.

Ozone NAAQS:

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds (VOCs) in the presence of sunlight. On January 6, 2010, the EPA proposed to lower the primary NAAQS for ozone designed to protect public health to a range between 60 and 70 ppb and to set a separate secondary NAAQS for ozone designed to protect sensitive vegetation and ecosystems.

On September 2, 2011, President Obama ordered the EPA to withdraw proposed air quality standards lowering the 2008 ozone standard pending the CAA 2013 scheduled reconsideration of the ozone NAAQS (the normal 5 year reconsideration period). States will move forward with area designations based on the 2008 75 ppb standard using 2008-2010 quality assured monitoring data. Our service territory will be designated as attainment, meaning it will be in compliance with the standard. In the interim, the 1997 ozone NAAQS will remain in effect.

Mercury Air Toxics Standard (MATS):

In 2005, the EPA issued the Clean Air Mercury Rule (CAMR) under the CAA. It set limits on mercury emissions by power plants and created a market-based cap and trade system expected to reduce nationwide mercury emissions in two phases. New mercury emission limits for Phase 1 were to go into effect January 1, 2010. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia vacated CAMR. This decision was appealed to the U.S. Supreme Court which denied the appeal on February 23, 2009.

The EPA issued an Information Collection Request (ICR) for determining the National Emission Standards for Hazardous Air Pollutants (NESHAP), including mercury, for coal and oil-fired electric steam generating units on December 24, 2009. This ICR included our Iatan, Asbury and Riverton plants. All ICRs were submitted as required. The EPA ICR was intended for use in developing regulations under Section 112(r) of the CAA maximum achievable emission standards for the control of the emission of hazardous air pollutants (HAPs), including mercury. The EPA proposed the first ever national mercury and air toxics standards (MATS) in March 2011. It was signed by EPA Administrator on December 16, 2011 and establishes numerical emission limits to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including HCl and hydrogen fluoride (HF). For all existing and new coal-fired electric utility steam generating units (EGUs), the proposed standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply.

The MATS regulation of HAPs in combination with CSAPR is the driving regulation behind our Compliance Plan and its implementation schedule. We expect compliance costs to be recoverable in our rates.

Greenhouse Gases

Our coal and gas plants, vehicles and other facilities, including EDG (our gas segment), emit CO2 and/or other Greenhouse Gases (GHGs) which are measured in Carbon Dioxide Equivalents (CO2e).

On September 22, 2009, the EPA issued the final Mandatory Reporting of Greenhouse Gases Rule under the CAA which requires power generating and certain other facilities that equal or exceed an emission threshold of 25,000 metric tons of CO2e to report GHGs to the EPA annually commencing in September 2011. GHG emissions have been reported as required to the EPA in 2011 for EDE and EDG. On January 11, 2012 EPA released the greenhouse gas data reported from large facilities and suppliers across the U.S. economy for the year 2010.

On December 7, 2009, responding to a 2007 U.S. Supreme Court decision that determined that GHGs constitute ‘‘air pollutants’’ under the CAA, the EPA issued its final finding that GHGs threaten both the public health and the public welfare. This ‘‘endangerment’’ finding does not itself trigger any EPA regulations, but is a necessary predicate for the EPA to proceed with regulations to control GHGs. On May 13, 2010, the EPA issued under the CAA its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule) to address GHG emissions from stationary sources, which became effective January 2, 2011. The rule sets thresholds for GHG emissions that determine when permits will be required under the New Source Review Prevention of Significant Deterioration (PSD) and title V Operating Permit programs applicable to new and existing power plants and other covered sources. Under the PSD program, required controls for GHG emissions would be determined based on Best Available Control Technology (BACT). EPA issued a BACT permitting guidance document on November 11, 2010. Missouri and Kansas have been delegated GHG permitting authority by EPA. Several parties have filed petitions with the EPA and lawsuits have been filed challenging the EPA’s Endangerment Finding and the Tailoring Rule.

In addition, on December 23, 2010 the EPA entered into an agreement with a number of state and environmental petitioners to settle litigation pending in the U.S. Court of Appeals for the District of Columbia Circuit that requires EPA to propose New Source Performance Standards (NSPS) for GHGs for fossil-fuel fired steam generating units by September 30, 2011 and to issue final GHG NSPS standards by May 26, 2012. The EPA has not to date issued a proposed GHG emissions rule for stationary sources.

A variety of proposals have been and are likely to continue to be considered by Congress to reduce GHGs. Proposals are also being considered in the House and Senate that would delay, limit or eliminate EPA’s authority to regulate GHGs. At this time, it is not possible to predict what legislation, if any, will ultimately emerge from Congress regarding control of GHGs.

Certain states have taken steps to develop cap and trade programs and/or other regulatory systems which may be more stringent than federal requirements. For example, Kansas is a participating member of the Midwestern Greenhouse Gas Reduction Accord (MGGRA), one purpose of which is to develop a market-based cap and trade mechanism to reduce GHG emissions. The

MGGRA has announced, however, that it will not issue a CO2e regulatory system pending federal legislative developments. Missouri is not a participant in the MGGRA.
The ultimate cost of any GHG regulations cannot be determined at this time. However, we would expect the cost of complying with any such regulations to be recoverable in our rates.

Water Discharges
We operate under the Kansas and Missouri Water Pollution Plans that were implemented in response to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received necessary discharge permits.
The Riverton Units 7 and 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. The regulations became final on February 16, 2004. In accordance with these regulations, we submitted sampling and summary reports to the Kansas Department of Health and Environment (KDHE) which indicate that the effect of the cooling water intake structure on Empire Lake's aquatic life is insignificant. KCP&L, who operates Iatan Unit 1, submitted the appropriate sampling and summary reports to the Missouri Department of Natural Resources (MDNR). In 2007 the United States Court of Appeals for the Second Circuit remanded key sections of these CWA regulations to the EPA. As a result, the EPA suspended the regulations and revised and signed a pre-publication proposed regulation on March 28, 2011 and is obligated to finalize the rule by July 27, 2012.
We will not know the full impact of these rules until they are finalized. If adopted in their present form, we expect regulations of Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) to have an impact at Riverton ranging from minor improvements to the cooling water intake structure to retirement of units 7 and 8. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit.
Our new Iatan Unit 2 and Plum Point Unit 1 are covered by the proposed regulation but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally impacted by the final rule.

Surface Impoundments
We own and maintain coal ash impoundments located at our Riverton and Asbury Power Plants. Additionally, we own a 12 percent interest in a coal ash impoundment at the Iatan Generating Station and a 7.52% interest in a coal ash impoundment at Plum Point. The EPA has announced its intention to revise its wastewater effluent limitation guidelines under the CWA for coal-fired power plants sometime in 2012. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits, including permits for coal ash impoundments. We do not have sufficient information at this time to estimate additional costs that might result from any new standards. All of the coal ash impoundments are compliant with existing state and federal regulations.
On June 21, 2010, the EPA proposed a new regulation pursuant to the Federal Resource Conservation and Recovery Act (RCRA) governing the management and storage of Coal Combustion Residuals (CCR). In the proposal, the EPA presents two options: (1) regulation of CCR under RCRA subtitle C as a hazardous waste and (2) regulation of CCR under RCRA subtitle D as a non-hazardous waste. The public comment period closed in November 2010. It is anticipated that the final regulation will be published in mid to late 2012. We expect compliance with either option as proposed to result in the need to construct a new landfill and the conversion of existing ash handling from a wet to a dry system(s) at a potential cost of up to $15 million at our Asbury and Riverton Power Plants. This preliminary estimate will likely change based on the final CCR rule and its requirements. We expect resulting costs to be recoverable in our rates.
On September 23, 2010 and on November 4, 2010 representatives from GEI Consultants, on behalf of the EPA, conducted on-site inspections of our Riverton and Asbury coal ash impoundments, respectively. The consultants performed a visual inspection of the impoundments to assess the structural integrity of the berms surrounding the impoundments, requested documentation related to construction of the impoundments, and reviewed recently completed engineering evaluations of the impoundments and their structural integrity. In response to the inspection comments, a qualified engineering firm has been selected to complete the recommended geotechnical studies and install new flow monitoring devices and settlement monuments at both coal ash impoundments. The project is expected to be completed by December 2012. The project will comply with all corrective measures and recommendations made by the EPA in its site assessment reports.

Appendix D

Plant Name	Boiler ID	Generator ID	Generator Nameplate Capacity (MW)	Missouri Jurisdictional Capacity (MW)	Initial Operation	Utility	State	Cooling Water	Cooling Water Source	Furnace Type	NOX Control	SO2 Control	Particulate Control	HG Control
Asbury	1	1	213	188	1970	Empire	MO	CT	Well	Cycl	SCR	*	Precip *	*
Hawthorn	5A	5	594	341	2001	KCP&L	MO	OT	River	Wall	SCR	Scrubber	Baghouse	**
Iatan	1	1	726	499	1980	KCP&L (70%), GMO (18%), Empire (12%)	MO	OT	River	Wall	SCR	Scrubber	Baghouse	ACI
Iatan	2	2	850	510	2010	KCP&L (54.71%), GMO (18%), Empire (12%)	MO	CT	Well	Tang	SCR	Scrubber	Baghouse	ACI
Jeffrey Energy Center	1	1	720	58	1978	GMO (8%)	KS	CT	Lake	Tang	* (1)	Scrubber	Precip	
Jeffrey Energy Center	2	2	720	58	1980	GMO (8%)	KS	CT	Lake	Tang	* (1)	Scrubber	Precip	
Jeffrey Energy Center	3	3	720	58	1983	GMO (8%)	KS	CT	Lake	Tang	* (1)	Scrubber	Precip	
Labadie	1	1	574	574	1970	Ameren Missouri	MO	OT	River	Tang	OFA/LNB	ULSC	Precip	**
Labadie	2	2	574	574	1971	Ameren Missouri	MO	OT	River	Tang	OFA/LNB	ULSC	Precip	**
Labadie	3	3	621	621	1972	Ameren Missouri	MO	OT	River	Tang	OFA/LNB	ULSC	Precip	**
Labadie	4	4	621	621	1973	Ameren Missouri	MO	OT	River	Tang	OFA/LNB	ULSC	Precip	**
LaCygne	1	1	893	256	1973	KCP&L (50%)	KS	OT	Lake	Cycl	SCR	*	Scrubber*	*
LaCygne	2	2	685	197	1977	KCP&L (50%)	KS	OT	Lake	Wall	*	*	Precip*	*
Lake Road	6	4	90	90	1966	GMO	MO	OT	River	Cycl		LSC	Precip	
Meramec	1	1	138	138	1953	Ameren Missouri	MO	OT	River	Tang	OFA/LNB	ULSC	Precip	**
Meramec	2	2	138	138	1954	Ameren Missouri	MO	OT	River	Tang	OFA/LNB	ULSC	Precip	**
Meramec	3	3	289	289	1959	Ameren Missouri	MO	OT	River	Wall	OFA/LNB	ULSC	Precip	**
Meramec	4	4	359	359	1961	Ameren Missouri	MO	OT	River	Wall	OFA/LNB	ULSC	Precip	**
Montrose	1	1	188	108	1958	KCP&L	MO	OT	Lake	Tang		LSC	Precip	
Montrose	2	2	188	108	1960	KCP&L	MO	OT	Lake	Tang	*	LSC	Precip	
Montrose	3	3	188	108	1964	KCP&L	MO	OT	Lake	Tang	*	LSC	Precip	
Plum Point	1	1	665	88	2010	Empire (50 MW ownership, 50 MW PPA)	AR	CT	River	Wall	SCR	Scrubber	Baghouse	ACI
Riverton	39	7	38	33	1950	Empire	KS	OT	River	Wall		LSC	Precip	
Riverton	40	8	50	44	1954	Empire	KS	OT	River	Tang		LSC	Precip	
Rush Island	1	1	621	621	1976	Ameren Missouri	MO	OT	River	Tang	OFA/LNB	ULSC	Precip	**
Rush Island	2	2	621	621	1977	Ameren Missouri	MO	OT	River	Tang	OFA/LNB	ULSC	Precip	**
Sibley	1	1	55	55	1960	GMO	MO	OT	River	Cycl	SNCR	LSC	Precip	
Sibley	2	2	50	50	1962	GMO	MO	OT	River	Cycl	SNCR	LSC	Precip	
Sibley	3	3	419	419	1969	GMO	MO	OT	River	Cycl	SCR	LSC	Precip	
Sioux	1	1	550	550	1967	Ameren Missouri	MO	OT	River	Cycl	OFA/RRI SNCR	Scrubber	Precip	Scrubber
Sioux	2	2	550	550	1968	Ameren Missouri	MO	OT	River	Cycl	OFA/RRI SNCR	Scrubber	Precip	Scrubber
			13,705	8,921										

* Installation of control equipment

** Planning installation of control equipment

OFA = Overfire Air LNB = Low NOX Burners SCR = Selective Catalytic Reduction SNCR = Selective Noncatalytic Reduction RRI = Rich Reagent Injection LSC = Low Sulfur Coal ULSC = Ultra Low Sulfur Coal ACI = Activated Carbon Injection OT = Once Through CT = Cooling Tower

(1) One unit-SCR installation, others may be required.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of an Investigation of the Cost to Missouri's Electric Utilities Resulting from Compliance with Federal Environmental Regulations	))))	Case No. EW-2012-0065

AFFIDAVIT OF MICHAEL E. TAYLOR

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Michael E. Taylor, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Staff Report on pages 1 - 35, and the facts therein are true and correct to the best of his knowledge and belief.

Michael E. Taylor

Michael E. Taylor

Subscribed and sworn to before me this 1st day of May, 2012.

LAURA HOLSMAN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 21, 2015
Commission Number: 11203914

Laura Holsman

Notary Public