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Kansas Corporation Commission
/S/ Susan K. Duffy
STATE CORPORATION COMMISSION

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Susan Talbot

THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of a General Investigation Into)
KCP&L and Westar Generation Capabilities,)
Including as these Capabilities May Be)
Affected by Environmental Requirements.)

Docket No. 11-GIME-492-GIE

INITIAL COMMENTS

COMES NOW, the prospective intervenor Sierra Club and responds as follows to the *Order Opening Docket, Setting Schedule, Granting Curb Intervention, Designating Prehearing Officer and Assessing Costs* (Order) issued by the State Corporation Commission of the State of Kansas (Commission) on January 27, 2011.

1. The Sierra Club is a national grassroots environmental organization with more than 600,000 members nationwide, and more than 4000 members in the state of Kansas. As explained further in Sierra Club's pending petition to intervene, filed February 9, 2011, Sierra Club and its Kansas Chapter support the wise allocation of energy resources, focusing specifically on ending the nation's reliance on polluting energy sources such as coal. Sierra Club, with expert assistance from Synapse Energy Economics, Inc., (Synapse), provides the following initial comments in response to the questions posed in the January 21, 2011, Order and intends to help the Commission and utilities establish the right mix of resources to fully and economically meet the state's present and future energy needs.[1] Long overdue life-saving environmental regulations are changing the landscape for electricity producers, and the utilities providing electricity to Kansas consumers stand at a crossroads between investing billions of dollars in aging infrastructure and choosing a mix of cleaner and renewable energy. Sierra Club looks forward to participating in this timely, and crucially important docket.

I. Introduction

2. As set forth in the Order, "the staff of the Commission (Staff) filed a Petition asking that a general investigation be opened (1) to determine how environmental upgrade requirements may affect the generation capabilities of (a) Kansas City Power and Light (KCP&L) and (b) Westar Energy, Inc., and Kansas Gas and Electric Company (collectively Westar), and (2) to establish criteria to be used when evaluating retrofit,

[1] Synapse Energy Economics, Inc., is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission staff, state attorneys-general, environmental organizations, federal government and utilities. A complete description of Synapse is available at its website, www.synapse-energy.com.

decommission, or replacement decisions," and requested the Commission to open a docket "to address issues described in Staffs petition."[2]

3. The Commission granted Staff's petition and opened a general investigation on January 27, 2011. The Commission directed KCP&L, Westar, and any intervenors to file initial comments by February 18, 2011, "addressing information regarding potential environmental upgrade requirements on the EGUs [electric generating units] owned by KCP&L and Westar, including questions listed in paragraphs 6 and 15." The February 18 deadline was extended to February 25 by Commission order. The Sierra Club, as a prospective intervenor, provides these initial comments pursuant to that directive.

4. The stated purpose of this general investigation docket is twofold:

> (1) determine how present and potential environmental upgrade requirements may affect the costs of the utilities' existing generation, and
>
> (2) to establish processes and criteria to ensure that retrofit, decommissioning, or replacement decisions are made on a sound least-cost basis taking into account all the available resource alternatives and their relative costs and risks.[3]

5. In order to assist the Commission and Staff in understanding the issues that should be considered in analyzing those decisions and in developing guidance for utility evaluations, the Commission:

> (1) directed all intervenors to answer three questions that are fundamental to any decision to carry out an environmental retrofit a generating unit,
>
> (2) directed the utilities to answer certain questions that would provide utility-specific information related to the three fundamental questions,
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> (3) directed parties to answer certain questions regarding risk sharing between shareholders and ratepayers, and
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> (4) invited parties to address any additional information that the Commission should consider regarding the potential environmental upgrade requirements on the EGUs owned by KCP&L and Westar.[4]

The Sierra Club supports the Commission's proactive approach to ensure sound decision-making and to ensure that the Commission has sufficient information to evaluate company decisions that could result in significant costs to ratepayers.

II. Fundamental Questions and Utility-specific Inquiries (¶¶ 6 and 8 of the Order)

6. According to the Commission, the full scope of retrofitting decisions will require the utilities to provide detailed answers to three fundamental questions, the answers to

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[2] Order at 1.

[3] Order at 1.

[4] Order at 8-9.

which will aid the Commission in future decisions regarding whether to mothball, retrofit, decommission, or replace generation capacity units.

7. The Sierra Club strongly urges the Commission to establish a comprehensive and consistent process for considering utility proposals for major investments in existing generating units. In general, the Commission's final guidelines must require:

> (1) a thorough inventory and description of all the relevant resource options, together with an assessment of their costs, benefits, uncertainties and risks, as well as the probabilities of those risks,
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> (2) an objective analysis of how those uncertainties and risks affect the performance of various resource plans individually and in combination,
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> (3) development of a plan relying on a portfolio of resources that manages risk and uncertainty to a reasonable level while delivering the lowest life cycle cost over the fullest possible range of plausible future scenarios.

8. Below, the Sierra Club addresses the Commission's three fundamental questions. We also discuss the specific questions the Commission posed to the companies in paragraph 8 of its scheduling order that relate to the fundamental questions, and have provided initial comments regarding the information and analysis that is relevant to those specific questions.

A. First fundamental question: "Is the capacity and/or energy provided by the plant to be retrofitted needed by the utility?"

9. The utility-specific questions related to this fundamental question include ¶ 8, questions c and d:

> c. What are Westar and KCP&L's expected capacity and/or energy needs over the appropriate investment planning horizons (e.g. 10, 15, 25 years) given the Companies' existing generation portfolios?
>
> d. If capacity and/or energy is not needed, then how should non-compliant plants be treated?

10. Regarding ¶ 8, question c, although the utilities can provide the best response here, the scope of Commission consideration and guidelines should include all material factors that affect resource needs and selection. Sierra Club reserves the right to review the information provided by the utilities and determine whether retrofit technologies and all other available resource options have been considered on a level playing field, accounting for their life cycle costs and respective risks and uncertainties, including a transparent and verifiable exposition setting out in detail all data, analysis, modeling and supporting documentation for each of the resource options considered, based on national best practices for utility resource planning and any additional relevant KS requirements. One widely accepted view of the types of information and analysis that should underlay a valid resource plan may be found in the National Action Plan for Energy Efficiency's *Guide to Resource Planning with Energy Efficiency*, 2007, available at http://www.epa.gov/cleanenergy/documents/suca/resource_planning.pdf. In any event, the Commission's criteria for evaluating additional investment in existing capacity should

be rigorous and require the utility to go beyond simply the question of whether a particular retrofit is mandated for continued operation.

11. Regarding ¶ 8, question d, if certain existing capacity is not necessary, for example, because it would not be economic to implement mandatory environmental upgrades, the Commission may have the option of treating such capacity as no longer used and useful. Traditional ratemaking practice provides that the remaining rate base for such plants, net of salvage value (which may be a positive or negative value), be shared between the Company and ratepayers. If the plant is still legally operable, the situation may be similar but can become more complicated. Sierra Club reserves the right to review the information provided by the utilities and other parties and to respond further on this issue.

B. Second fundamental question: "If the capacity and/or energy is needed, then is the decision to retrofit a more economically efficient choice than decommissioning the existing plant and building a new plant?"

12. In paragraph 8, the Commission poses certain utility-specific questions that are directly pertinent to this question:

> a. What EPA and KDHE regulatory programs [current and emerging] apply to each EGU within the KCP&L and Westar fleets?
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> b. What are the emission allowances for each unit?
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> e. If capacity and/or energy is needed, should KCP&L and Westar retrofit existing non-compliant plants or build new plants?
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> i. If replacement of a plant is considered as an option, what criteria should be used to determine the size and type of the generation plant to be built?
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> j. What factors were considered in any hypothetical resource portfolio scenarios which have been run?
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> k. How do Westar and KCP&L plan to regulate the wind and other renewable generation that is required by the Renewable Energy Standards Act (KSA 66-1256 through 66-1262)? If Westar and KCP&L plan to add generation to regulate wind and other renewable generation, how much generation and what fuel sources are planned to be used at these new plants used for regulation?

13. This fundamental question, along with the associated requests for utility-specific information, gets to the heart of what is necessary to determine whether retrofitting is a more economically efficient choice than decommissioning an existing plant and building a new one. The determination of the most economically efficient choice requires a comprehensive and detailed assessment of the costs associated with a variety of options. This assessment must include a full understanding of all of the costs that are associated with specific options, as well as an understanding and evaluation of costs that can reasonably be anticipated for specific options. Thus the scope of Commission consideration and guidelines should include all material factors that affect resource cost comparison and relative risk assessment. We recommend that the Commission's guidelines detail the relevant information, methodologies and supporting documentation

the utilities must provide for this question and the related paragraph 8 questions (we address specifically subparts a, b, e, i, j, and k). These requirements should be based on national best practices for utility resource planning as well as relevant Kansas requirements. In general, the scope of the Commission's consideration and the guidelines should include a comprehensive set of issues and factors and should reflect a multi-pollutant approach to evaluating the likely costs of continued operation and retrofit, rather than considering one regulation at a time.

14. In short, the Commission's questions provide a very useful starting point in understanding a utility's decision-making regarding whether to pursue retrofits or new construction in response to an identified capacity and/or energy need.

15. Electric generating units in Kansas and owned by Kansas utilities face significant compliance obligations and costs associated with current and emerging regulatory programs (¶ 8, question a). These must be factored into any hypothetical resource portfolio that a company considers in its planning decisions (¶ 8, question j). The U.S. Environmental Protection Agency (EPA) is poised to promulgate a series of rules that will apply to KCP&L's and Westar's fleets of generating units. The following is a description of those rules and the possible retrofit technologies required to meet new environmental standards; a discussion of the applicability of those rules to KCP&L's and Westar's fleets; and the approximate timeframes for compliance. More detail is given in response to ¶ 8, question a, regarding which specific environmental retrofits might be required at specific KCP&L and Westar units due to these, and other regulatory requirements. The rules are grouped for discussion under relevant federal statutes, but the state of Kansas or Missouri (where certain of the relevant plants are located) will take the lead in implementing many of these regulations through state programs. Table 1, below in these initial comments, provides an overview.

16. Therefore, the Commission's question regarding current and emerging regulations is essential to understanding the full forward-going costs that KCP&L and Westar would incur to operate their coal-fired power plants. Indeed, these regulatory requirements will either trigger significant investments in aging coal-plants or trigger retirement.

17. This series of environmental and public-health based rules and their application to specific KCP&L and Westar units requires thoughtful analysis. Sierra Club, with expert analysis from Synapse Energy Economics has tried to provide as much information for the Commission as possible at this point in the proceedings. Sierra Club is happy to provide further briefing if the Commission has additional questions.

Table 1: Summary of existing and emerging regulations

Law	Regulation	Applicability to generating units	Time period	Pollutants and potential controls
Clean Air Act	Regional Haze	KDHE has determined applicability (e.g., LaCygne and Jeffrey units)	Final. Up to 5 years from determination	SO_2 NO_x
	Clean Air Transport Rule	Electric generating units in KS and MO	Final rule expected 2011. Implementation 2012	SO_2 NO_x
	Air Toxics	KCP&L and Westar units that are "major" sources (i.e. >10 t/yr of one pollutant or >25 t/yr of combined pollutants)	Proposed 03-2011 Final 11-2011 Implementation 3 years after final rule, and no later than 2015	Includes acid gases, mercury, non-mercury metals. Potential controls include wet scrubbers, SCR, bag houses, activated carbon injection.
	National Ambient Air Quality Standards revision	Potentially affected include plants in attainment areas that increase emissions in that area, and plants in non-attainment areas.		SO_2, NO_x, fine particulates. Potential controls include wet scrubbers, SCR, baghouses.
Clean Water Act	Cooling Water regulations for existing plants	All existing power plants	Proposed 03-2011 Final 07-2012 Implementation: earlier of permit renewal or a few years following final rule (i.e. 2015?)	Plants using once through cooling are likely to retrofit to closed-cycle cooling
	Effluent limitation guidelines - update	All plants requiring CWA discharge permit	Proposed mid 2012 Final 01-2014 In the interim, case by case determination for permit renewal	Includes dissolved and undissolved metals. Control technologies include physical and/or chemical treatment, zero liquid discharge, biological treatment and reverse osmosis
Resource Conservation and Recovery Act	Coal Combustion Waste	All coal-fired power plants	Proposed 2010 Final early 2012	Heavy metals and toxins. Controls include phasing out surface impoundments and requiring composite liners for new/expanded landfills
Clean Air Act – Greenhouse Gases	New Source Review	Units undergoing major modification	Final Implementation 01-2011 and 07-2011	Six greenhouse gases Case-by-case determination, may include cleaner fuel, controlling fugitive emissions, carbon sequestration, boiler efficiency
	New Source Performance Standards for Electric Generators	Existing plants with modifications	Final 05-2012 Implementation 3-4 years after final rules (i.e. 2016?)	To be determined

18. Below is a summary of existing and emerging regulations, and their applicability to KCP&L and Westar units, grouped under the headings of the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, and regulation of greenhouse gases under the Clean Air Act.

(1) Clean Air Act

Clean Air Act Regional Haze Planning and Rules

Description: The Clean Air Act aims to achieve natural visibility in all Class I areas (national parks, etc.) by 2064. See 42 U.S.C. § 7479–7479B. The Clean Air Act and EPA's implementing rules require states to create plans to achieve natural visibility with enforceable reductions in haze-causing pollution from individual sources and "reasonable further progress" milestones. Sources impacting visibility may require enforceable emissions limits known as "best available retrofit technology" (BART) limits; those limits are set on a case-by-case assessment of the relative costs of pollution reductions as against the visibility gains achieved.

KCP&L and WESTAR Plants Subject to the Rule: The Kansas Department of Health and Environment (KDHE) has determined which units are subject to BART and what emission limits apply to the various units to achieve the Clean Air Act's visibility mandates. Regional haze reduction requirements are one of the driving forces behind the retrofits being considered for LaCygne and Jeffrey.

Relevant Dates: BART compliance is required within 5 years of approval of a state's haze plan. In this case, it appears that formal deadlines for compliance have been agreed upon for at least some of the units.

Pollutants Addressed and Possible Controls Required: Haze is caused in large part by fine particles. Reductions in sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) are required.

Clean Air Transport Rule

Description: In the CAA, Congress required upwind states to cease emissions that (a) contribute significantly to a downwind state's nonattainment of National Ambient Air Quality Standards ("NAAQS"), or (b) interferes with the downwind state's ability to maintain NAAQS. See 42 U.S.C. § 7410(a)(2)(D)(i)(I). Because upwind states failed to fulfill this duty, EPA has stepped in to help downwind states achieve healthy air. The "Good Neighbor" rule, or Transport Rule, implements the Clean Air Act's (CAA's") "Good Neighbor" provision will help down-wind states control pollution from power plants that otherwise blows into downwind states. The rule will cut pollutants, sulfur dioxide (SO_2) and nitrogen oxide (NO_x) that form ozone and fine particles in the atmosphere, which aggravate asthma and cause heart and lung problems. Pollution from Kansas and Missouri contributes to nonattainment in TX, WI, IL, IN, IA, KY, MI, OH, TN, and PA. See 75 Fed. Reg. 45210 (August 2, 2010).

KCP&L and WESTAR Plants Subject to the Rule: Kansas is covered by the proposed Transport Rule's requirements for protection of fine particle NAAQS and protection of the 8 hour ozone standard. Power plants in Missouri are required to protect the fine particle NAAQS only. Missouri is in the stringent "group 1" for SO_2 reductions and Kansas is in the moderate "group 2" for SO_2 reductions. Initial reductions are required in 2012, with additional reductions in 2014 in some states. Power plants over 25 megawatts are subject to the proposed Transport Rule's emissions reduction targets for EGUs; plants may purchase credits instead of installing pollution-controls, but plants within the state must, as a whole, achieve the specified reductions.

Relevant Dates: A final rule is expected in mid-2011. The first set of pollution reductions will occur in 2012.

Pollutants Addressed and Possible Controls Required: The reductions required and the trading scheme of the final rule will dictate the emissions reductions KCP&L and Westar must achieve. Controls for SO_2 or NO_x should be considered.

Air Toxics Standards for Electric Generating Units

Description: Next month, the EPA is expected to propose an updated air quality standard for life-threatening hazardous air pollution from power plants, such as mercury and arsenic. This air toxics safeguard is also called the "Power Plant MACT" Rule (Maximum Available Control Technology). Pursuant to Clean Air Act §112(d), EPA will promulgate emission limits for hazardous air pollutants that are based on the emissions of the cleanest existing sources. Existing sources will be required to meet the applicable emissions limit, using any technology that will reduce hazardous air pollutants sufficiently to do so.

KCP&L and WESTAR Plants Subject to the Rule: The Air Toxics rule will apply to all of KCP&L and Westar's plants that are "major" sources of hazardous air pollutants—those which have the potential to emit more than 10 tons of any one hazardous air pollutant, or more than 25 tons of any combination of hazardous air pollutants. All plants must meet the "MACT" emission limits set according to the cleanest ("best performing 12%) existing coal-fired power plants.

Relevant Dates: The proposed rule is due for public comment on March 16, 2011, with a final rule sometime in November 2011 (pursuant to a consent decree). KCP&L's and Westar's plants will have to meet the rule's limits within three years of the adoption of final rule, with a one year extension available with EPA approval—putting the latest date of compliance around November 2015.

Pollutants Addressed and Possible Controls Required: The proposed rule is expected to set "maximum available control technology" emissions limitations for Hazardous Air Pollutants, including but not limited to acid gases, mercury, and non-mercury metals. The best-controlled units in the country use wet scrubbers, SCR, and baghouses to control hazardous air pollutants. These controls may be required by the final rule. Activated carbon injection may be required to control mercury. Companies may be able to comply with required mercury reductions by fuel switching, running existing SCR units year-round, installing control technology, or some combination of these strategies.

National Ambient Air Quality Standards

Description: EPA promulgates "National Ambient Air Quality Standards" (NAAQS) pursuant to the authority granted by Clean Air Act § 109 (42 U.S.C. §7409). Primary NAAQS are set to protect public health, and are supposed to be revisited at five year intervals. EPA is currently working to improve "national ambient air quality standards" (NAAQS) for SO_2, ozone, and PM2.5 (fine particulate) to assure protection of public health. New standards for these pollutants will trigger the process for designating areas as either in "attainment" or "nonattainment" with the new standards. Widespread nonattainment designations under all the new standards are expected. In nonattainment areas, sources must automatically comply with moderate emission limitations known as "Reasonably Available Control Technology" (RACT), and new sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER) as well as emission offsets. 42 U.S.C. § 7502; 42 U.S.C. § 7503. In attainment areas, new sources must demonstrate they do not cause or contribute to a violation of the new standards. 42 U.S.C. § 7475. For areas that are designated nonattainment, Kansas and Missouri must develop a "state implementation plan" (SIP) designed to attain the standards within 5 years of being designated nonattainment. Those plans may contain additional emissions reduction requirements at specific plants.

KCP&L and WESTAR Plants Subject to the Rule: If KCP&L or Westar seek a permit that would lead to increased emissions in an attainment area, they must ensure the increases would not cause or contribute to a violation of the new NAAQS. In nonattainment areas, the utility seeking a permit that would lead to increased emissions must comply with very stringent emissions control requirements, must offset all of the increased emissions at nearby sources, and must demonstrate that all other plants owned by the company are in compliance with applicable laws. Plants that cause or contribute to "nonattainment" for any of the NAAQS must comply with "reasonably available control technology" (RACT) limits regardless of whether the plant seeks to increase emissions.

KCP&L' and Westar's plants that are either located in the following counties, or that cause or contribute to non-attainment in the following counties, will need RACT level controls for sulfur dioxide and nitrogen oxides. Jackson County, Missouri is currently violating the 1 hr SO_2 standard. Levenworth, Linn, Sedgwick, Sumner, Trego, and Wyandotte counties in Kansas, and Cass, Cedar, Clay, Clinton, Greene, Lincoln, Monroe, Perry, St. Charles, St. Louis, and Sainte Genevieve counties in Missouri are currently violating the proposed ozone standards.

Relevant Dates: SO_2: EPA has issued a final 1 hr SO_2 rule. 75 Fed. Reg. 35520 (June 22, 2010). Ozone: EPA has issued a proposed rule, with a final rule expected by July 2011. 75 Fed. Reg. 2938 (Jan. 19, 2010). PM2.5: A proposed rule is expected by mid-2011. States will have one year from the time the standard is final to designate nonattainment areas, with one more year for EPA to finalize those areas.

Pollutants Addressed and Possible Controls Required: Construction permit applications and non-attainment designations will drive pollution control requirements for KCP&L's and Westar's fleets. State-of-the-art controls would include a wet scrubber for SO_2, selective catalytic reduction (SCR) for NO_x, and a baghouse for fine particulate.

(2) Clean Water Act

Clean Water Act Cooling Water Intake Structure Rule

Description: EPA is expected to propose a rule in March 2011, which will implement the requirements of Section 316(b) of the Clean Water Act at existing power plants. 33 U.S.C. § 1326. Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under section 316(b), EPA will likely set a performance standard(s) that reflects "best technology available" for reducing the impacts of cooling water intake structures including reducing the significant "impingement" and "entrainment" impacts of cooling water intake structures on aquatic life.

KCP&L and WESTAR Plants Subject to the Rule: All of KCP&L and Westar's plants will have to meet the new standards set by EPA in its rule, which will apply to all existing power plants. (A rule applying to new plants is already in place.) In practice, the portion of KCP&L's and Westar's fleets that currently use once-through cooling will face retrofits to closed-cycle cooling. Even without the rule, case-by-case "best technology available" determinations are required. These determinations must occur when the water discharge permits for the plants are renewed. Thus, the retrofits could be required as soon as the next permit renewal, or once the rule is promulgated, within a few years of the final rule. *See* EPA Memo by Benjamin Grumbles, Implementation of the Decision in Riverkeeper v. EPA, Remanding the Cooling Water Intake Structure Phase II Regulation (March 20, 2007).

Relevant Dates: Pursuant to a settlement agreement, EPA must promulgate a proposed rule by March 14, 2011, and a final rule by July 27, 2012.

Pollutants Addressed and Possible Controls Required: The rule will addresses the environmental impacts of cooling water intake structures, including impingement and entrainment of aquatic organisms. Closed-cycle cooling will likely be required for at least some plants, which in most cases requires a cooling tower and an infrastructure improvement on the intake mechanism itself.

Effluent Limitation Guidelines for the Steam Industry

Description: The Clean Water Act requires EPA to develop "effluent limitation guidelines—clear rules for what large industrial sources of water pollution can discharge into nearby waters. See 33 U.S.C. § 1311; 40 C.F.R. 423. These rules must consider what is "economically achievable" and must be updated at least once every five years to keep up with improving treatment technology. Although EPA is supposed to update its rules regularly, the power plant rules were last updated in 1982, and so are almost thirty years out of date. Under the last administration, EPA began a detailed series of studies designed to allow it to update the rules. Importantly, EPA has already begun a detailed series of studies, which have found that power plant water discharges are associated with fish kills, serious river contamination, and other public health risks.

KCP&L and WESTAR Plants Subject to the Rule: All of the plants that require a Clean Water Act discharge (NPDES) permit will be subject to the new effluent guidelines.

Relevant Dates: Pursuant to a settlement, the proposed rule is due by mid-2012, and a final rule is due in January 2014. As with the §316(b) rule, NPDES permits that are renewed in the interim before the final rules are applicable still need to go through case-by-case determinations about what technologies are available to treat effluent. *See*: EPA Memo from James A. Hanlon re: National Pollutant Discharge Elimination System (NPDES) Permitting of Wastewater Discharges from Flue Gas Desulfurization (FGD) and Coal Combustion Residuals (CCR) Impoundments at Steam Electric Power Plants (Jun. 7, 2010).

Pollutants Addressed and Possible Controls Required: EPA may create guidelines for a number of harmful pollutants, including dissolved and undissolved metals, including mercury, selenium, arsenic, etc. Available technologies to treat effluent include physical/chemical treatment, zero-liquid discharge, biological treatment, and reverse osmosis.

(3) Resource Conservation and Recovery Act

Description: Coal-fired power plants generate very large volumes of ash. That ash is generally placed in ponds or landfills that have very few protections against leaks, groundwater contamination, or catastrophic failure. EPA has proposed regulation of ash, or "coal combustion residue" (CCR) as either a Subtitle C "hazardous waste" or Subtitle D "solid waste" under the Resource Conservation and Recovery Act (RCRA). 75 Fed. Reg. 35127 (June 21, 2010). If EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system will apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. The coal combustion rulemaking is required as a result of a combination of missed statutory deadlines and court orders covering some 30 years. The 1980 Bevill amendment, part of the Solid Waste Disposal Act amendments to RCRA, exempted coal combustion residues from regulation for two years while EPA gathered additional information about such wastes. The EPA missed that deadline and several subsequent deadlines, which prompted litigation that eventually resulted in this rulemaking. The original Bevill Amendment suggested that EPA should regulate coal combustion wastes if further study yielded evidence proving that CCW was a threat to human health and the environment. In the 30 years since that Amendment was passed, EPA's studies and research have produced a growing body of evidence that overwhelmingly support a subtitle C regulation of CCR to protect human health and the environment.

KCP&L and WESTAR Plants Subject to the Rule: All coal-fired plants that generate CCR will be required to comply with the rule. Different requirements will apply depending on whether CCR is stored on-site or shipped off-site.

Relevant Dates: EPA has already accepted public comment on its proposed rule. A final rule is expected in early 2012. Meanwhile, current liability may exist if ponds are leaking into ground and/or surface waters.

Pollutants Addressed and Possible Controls Required: CCR contains heavy metals and toxins found in coal burned at the power plant. Existing surface impoundments will be phased out and all new and expanded landfills will require composite liners. Groundwater monitoring will be required for all landfills. There are developments on several regulatory fronts that may have a considerable impact on how and at what cost CCR must be handled and disposed of. Perhaps the one that looms largest is EPA's current consideration of whether to propose to classify CCR as a hazardous waste under Subtitle C of the Resource Conservation and Recovery Act (RCRA) or retain its current non-hazardous classification but impose more stringent requirements under Subtitle D of RCRA. Consideration of the uncertainties surrounding this regulation—like all other uncertainties—is fundamental to reaching a decision that would be in the public interest.

(4) Greenhouse gas rules under the Clean Air Act

Tailoring Rule and New Source Review

Description: The Clean Air Act requires major new stationary sources of air pollution—and existing sources making major modifications—to receive permits certifying that they will limit their emissions to the rate achievable by the best available control technology (BACT) before they begin construction. 42 U.S.C. § 7475(a)(3). This BACT requirement applies for every "pollutant subject to regulation" under the Clean Air Act that is emitted over certain thresholds – and that includes greenhouse gases.

KCP&L and WESTAR Plants Subject to the Rule: By rule, EPA is phasing in the major source greenhouse gas permitting program. Beginning January 2011 with Phase 1, only sources that would already be included in preconstruction permitting due to their emissions of other pollutants will have to install greenhouse gas controls if they emit more than 100,000 tons per year of CO_2e (for new sources) or increase their emissions by 75,000 tons per year CO_2e (for modifications). In Phase 2, beginning July 2011, all new sources emitting more than 100,000 tons per year of CO_2e will need permits, along with any major modification projects with emissions of more than 100,000 tons per year of CO_2e that increases its emissions by at least 75,000 tons per year CO_2e.[5] EPA will also

[5] Carbon dioxide equivalent (CO_2e) means the global warming potential of a greenhouse gas (GHG) over a given time period (the typical standard is 100 years) using carbon dioxide (CO_2) as a reference. For example, over a 100-yr period, every unit of methane gas has 21 times more global warming potential than carbon dioxide. Therefore, methane gas carries a CO_2e weight of 21, while CO_2 carries a CO_2e

issue a separate rule addressing permitting for smaller sources (those emitting above 50,000 tons per year of CO_2e), which will take effect July 1, 2013. EPA will address sources below 50,000 tons per year in a subsequent study and rulemaking, to be finalized by April 30, 2016. Therefore, any KCP&L or Westar plant that undergoes a major modification, subject to the phased implementation described above, increasing greenhouse gases by more than 75,000 tons must undergo new source review permitting.

Relevant Dates: Phase 1 starts on January 2, 2011, and Phase 2 starts July 1, 2011.

Pollutants Addressed and Possible Controls Required: A suite of six greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride (SF_6). Required controls will be determined on a case-by-case basis, taking cost into account, and may include using cleaner fuels (burning gas rather than coal, for instance), controlling fugitive emissions, carbon sequestration, and using more efficient boilers.

New Source Performance Standards for Electric Generating Units

Description: New source performance standards (NSPS) are baseline, uniform national air pollution limits that apply to specific source categories (e.g. fossil fuel power plants, refineries, cement plants). For new and modified sources, EPA issues separate standards for each source category covering those pollutants emitted in significant quantities. The standard is based on what is achievable through the best system of emissions reduction that the Administrator determines has been adequately demonstrated, taking cost into consideration. For existing sources, this standard can consider the remaining useful life of the facility. The Clean Air Act requires major new and expanded industrial facilities to comply with the NSPS for their source category. 42 U.S.C. § 7411.

KCP&L and WESTAR Plants Subject to the Rule: For KCP&L's and Westar's existing fleets, certain types of modifications will trigger compliance with the New Source Performance Standard for Greenhouse Gases.

Relevant Dates: EPA will issue the final NSPS and guidance for power plants in May, 2012. The standards for existing sources will take effect 3-4 years after the standards for new sources.

19. The above summaries exhibit the potential synergistic magnitude of existing and proposed regulatory requirements. These mandates will inevitably inform utilities' decisions as they make future resource allocations to meet customer demand. Given the sheer number and wide coverage of these mandates, it is essential that the Commission and the utilities consider their potential impact in a cohesive, rather than singular, case-by-case basis for future utility planning.

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weight of 1. In greenhouse gas accounting, standard practice is to convert all GHG emissions to CO_2e to measure the total global warming potential of all emitted gases.

20. In ¶ 8, question (b), the Commission requests information regarding the emission allowances for each unit. The utilities will best answer this question. However, generally, Clean Air Act Title V operating permits dictate the emission rates for each of KCP&L's and Westar's plants. Sierra Club reserves the right to review at the information provided by the utilities and determine whether all applicable requirements are met through the current Title V operating permits for the plants, or whether those permits are in some way deficient, thus changing the quantity of "allowable" emissions, and, if necessary, to seek an opportunity to conduct discovery. The BART determinations, potential nonattainment designations, and various rules described herein may also alter the allowable emissions rates at some or all of KCP&L and Westar's units.

21. Questions a, e and i of ¶ 8 underscore the importance of a consistent decision-making process for deciding whether to retrofit existing plants, new plants or employ some other resource. In deciding whether to retrofit existing non-compliant plants, build new plants or select some other resource, and for determining the size and type of replacement plants, utilities must consider the market cost of existing, unused natural gas capacity, the cost of a new combined cycle natural gas plant, as well as that of wind, other renewables, demand response, and energy efficiency, in addition to the specific retrofit costs faced by an individual unit.

22. In ¶ 8, question j, the Commission asks about factors the utility has considered in any hypothetical resource portfolio scenarios it may have run. This question gets to some of the most important, and also some of the most difficult, aspects of evaluating resource options—those associated with risk and uncertainty. It is critical for companies to consider a reasonable range and intensity of risks and uncertainties, particularly those associated with environmental regulation. These include carbon costs, ozone regulation, mercury regulation, coal combustion waste risks and requirements, and a lengthy list of pending regulatory issues, as discussed above in response to ¶ 8, question a. We recommend that utilities be directed to include the costs and risks of existing and emerging regulations on a joint, multi-pollutant basis in evaluating resource portfolio scenarios, even when the final form or timing of a regulation is unknown, given the capital intensive and long-lived nature of investments in the electric industry.

23. In ¶ 8, question j, the Commission asks Westar and KCP&L how they plan "to regulate the wind and other renewable generation that is required by the Renewable Energy Standards Act (KSA 66-1256 through 66-1262)?"[6] The Commission also asks, "If Westar and KCP&L plan to add generation to regulate wind and other renewable generation, how much generation and what fuel sources are planned to be used at these new plants used for regulation?" The above questions are relevant not only with respect to the cost and functionality of those renewable resources, but also to how well they can perform as alternatives to the proposed environmental retrofits to existing fossil plants. This is an important issue, as integration and interconnection costs, requirements and uncertainties can inappropriately burden renewable generation in resource comparisons. Furthermore, imposition of inappropriate requirements or failure to clarify standard

[6] From the context, it is clear that the Commission's interest is in *frequency* regulation and other forms of control for the output of non-dispatchable renewable resources for the purposes of system integration.

requirements, have been such a burden in the past that the U.S. Federal Energy Regulatory Commission has found it necessary to impose national standards for interconnection. If the companies impose or assume for planning purposes unnecessary, inappropriate, or excessively burdensome interconnection and integration requirements or limitations on renewables, this Commission cannot fairly assess the need and justification for environmental retrofits to existing fossil fuel plants. Therefore, the Commission should require the companies to provide documentation supporting their answers to this question that is complete, transparent and sufficient to determine the necessity and appropriateness for any such requirements, assumptions or burdens. Sierra Club reserves the right to review the information provided by the utilities and determine whether they have met this standard and, if necessary, to seek an opportunity to conduct discovery.

C. Third fundamental question: "If the retrofit choice is the better choice, then has the utility chosen the best retrofitting option?"

23. The Commission's requests for information from the companies, ¶ 8, questions f-h, are related to this fundamental question.

> f. What criteria should be employed to determine optimal retrofit configurations to meet regulatory requirements? Has this analysis been performed for individual plants? Which plants?
>
> g. Do the environmental retrofit projects that are currently installed, under construction, or planned, represent the end of the upgrading process for their corresponding generation unites, or will the environmental retrofit projects, in turn, require additional improvements to these units?
>
> h. For any planned but incomplete environmental upgrades, has analysis been performed on how the planned upgrades may impact the expected life of the plant at the completion of the upgrades? If so, what criteria for analysis was used?

24. Sierra Club's response to the various analyses the utilities have done in response to these questions will be addressed on reply. Here, the scope of Commission consideration and guidelines should include all material factors that affect resource cost comparison and relative risk assessment applied to decisions between retrofit technologies and replacement or retirement. Sierra Club reserves the right to review the information provided by the utilities and determine whether all available resource options have been considered on a level playing field, with their life cycle costs and respective risks and uncertainties accounted for. The most reliable and comprehensive approach to such examination would be the preparation of a long-term resource plan by the utility. Such a resource plan is widely recognized in the field of electric utility planning to be appropriate and wise. More than twenty-five years of utility and Commission experience nationally in the field of power planning support this conclusion. Further, two broad principles are central to resource planning practice and should be required by the Commission. The first is to consider all resources on a "level playing field." That is, the development of the IRP considers all resources that may contribute to meeting need. It also means that energy efficiency and demand response (together, demand-side management) resources, transmission and distribution resources (including improvements to transmission and distribution efficiency), and all types of generation resources must be

considered on an equal basis. The second is that the plan should be an integrated portfolio of resources with the mix of resources that will provide adequate and reliable service at the lowest life cycle cost. As both of these resource planning practices are calculated to lead to adequate and reliable utility service at least cost to consumers, it is sound public policy for the Commission to require such resource plans. The Commission should also assess the uncertainties and risks attendant on a resource plan. A resource plan that is projected to have the lowest life cycle cost under one set of assumptions about the future, may or may not also be the best under another set of assumptions. Assumptions that can make a material difference to the performance of resource plans include, but are not limited to, (1) load growth and other factors affecting the size and timing of resource needs over time, such as trends in customer types, end use make up and load shape, (2) cost, availability and deliverability of fuels, equipment, construction materials and expertise, labor, land, transmission service and other goods and services that determine the cost of the various resources in the portfolio, (3) financial factors, such as inflation rates, utility bond ratings and changes in the rating criteria, cost and availability of various types of insurance, cost and availability of various types of capital, (4) factors relating to implementation schedules and "lumpiness" of various resource options, such as construction or installation times or delays in those times, risk of project failure or cost increase, (5) environmental and regulatory risks, such changes in emission standards (including the likelihood of CO_2 regulations), new emission standards or fees, permitting risk, and (6) planning risk, for example, the risk that a resource will become obsolete or unnecessary while under construction. While the technicalities can be somewhat abstract, the essence of risk and uncertainty assessment in this context is to measure the variability of a resource portfolio's results due to uncertainties in factors or assumptions such as those listed in the preceding answer. The Commission should look for (1) a thorough inventory and description of the relevant risks, together with an assessment of their probabilities, (2) an objective analysis of how those risks impact the performance of various resource plans individually and in combination, (3) development of a plan relying on a portfolio of resources that manages risk and uncertainty to a reasonable level while delivering the lowest life-cycle cost over the fullest possible range of plausible future scenarios. In order to facilitate review by the Commission and parties, and to promote accuracy, these assessment and data gathering activities should be transparent (clear and understandable to the Commission, the parties and the public), fully documented and supported by work papers and methodologies that allow the Commission and the parties to determine their validity, quantitative whenever possible, and treat all resources on a level playing field. Cost-benefit comparisons of resources and portfolios should be carried out using one or both of the two tests recommended above.[7] The Scope of Commission consideration and guidelines should include comprehensive set of issues and factors, including multi-pollutant approach (not one regulation at a time) to evaluating likely costs of continued operation and retrofit.

25. In developing guidelines for information related to question f in ¶ 8, the Commission should employ criteria to determine the optimal configuration to meet regulatory requirements that consider the full forward-going cost of operating coal-fired

[7] See, also, related discussion in ¶¶ 10 and 11 of these initial comments.

power plants in light of a rapidly changing landscape that disfavors coal, and that compare those costs to the variety of alternatives available to KCP&L and Westar. Underlying these considerations are the principles of prudency that apply to ratemaking, including the obligation for ongoing reassessment of avoidable costs.

26. As framed, the Commission asks how it should determine which "retrofit" configurations are optimal to meet regulatory requirements. Sierra Club urges the commission to think beyond a simple selection among alternative power plant retrofits to determine the optimal configuration for meeting regulatory requirements over the long term. When compared with the high cost of traditional retrofits, options such as new wind generation, demand-side management, energy efficiency, fuel switching at the existing units, and underutilized and/or new combined cycle natural gas capacity, in combination with coal-unit retirements, may present the "optimal" cost and risk configuration for complying with new environmental and public health-based requirements. Therefore it is important to consider this question in two ways: (1) what are the required retrofit configurations to meet regulatory requirements if retrofit is chosen; and (2) what is the optimal way to meet regulatory requirements including non-retrofit options.

27. Synapse conducted an analysis of the forward-going economic merit of the existing coal fleet in Kansas, and KCP&L and Westar coal units in Missouri, collectively referred to as "the coal fleet." Using publicly available data, Synapse estimated the current running cost of the coal fleet in 2008, as well as the expected forward-going cost of the fleet following implementation of a suite of measures that may reasonably be needed to meet the environmental compliance criteria detailed above in these initial comments.[8]

28. As a basic, minimal test for a rational economic decision, Synapse compared the forward-going cost of each unit against other options for meeting the power needs of consumers. For purposes of this analysis, the economic merit of each existing coal unit from the fleet is defined as the differential between Synapse's estimates of (1) the environmentally compliant forward-going cost per MWh of that unit and (2) the cost per MWh to produce the same amount of generation from each of the following resource alternatives:

1. New, gas-fired combined cycle generators,
2. Existing gas-fired combined cycle generators,
3. Wind power, and
4. Energy efficiency

[8] "Future revenue requirements" are defined here as the all-in cost of generation and operations and maintenance ("O&M"), as well as the additional costs of capital improvements to meet environmental regulations, and the O&M costs of operating these environmental upgrades. This simple analysis does not examine changes in dispatch or operational use that might occur as a result of implementing environmental controls. For the purposes of the analysis, we assume that the average capacity factors of units in the coal fleet in 2008 and 2009 represent their current optimal deployment. These capacity factors are also used to estimate the impact of fixed costs, such as capital expenditures and fixed O&M costs, on the forward-going cost.

29 The following sections describe Synapse's estimate of the current fleet's operating costs, the future revenue requirements for an environmentally compliant coal fleet, and the estimated economic merit for each unit in the coal fleet.[9]

Current Fleet Operating Costs

30. Synapse characterized the current running costs of each coal unit in the study region, based on publicly available data in 2008, as well as generation in 2009. The twenty-three (23) units in this database all reported generation in 2008 and 2009, burn coal as a primary fuel, and are either within the State of Kansas or are owned or operated by KCP&L or Westar. The generating units and their associated nameplate capacities are shown in the attached **Exhibit Sierra Club-1.** The nameplate capacity of each generating unit is taken as a fixed value. Generation output and capacity factor are taken as an average between reported 2008 and 2009 annual generation, reported by each individual generator.

31. To estimate fuel costs, Synapse calculated the reported coal-component heat rate at each of the 23 units in this analysis (MMBtu/MWh), the total reported quantity of coal consumed at each unit (tons), and the prices paid for delivered coal as reported to the EIA (¢/MMBtu). This information was used to estimate the weighted average delivered price of coal at each unit in the coal fleet.

32. For the purposes of this analysis, Synapse used O&M assumptions from the NERC 2010 Reliability Assessment to estimate fixed and variable O&M costs. Costs were categorized with economies of scale based on the capacity of the plant. Assumed O&M costs are given in Table 1 of **Exhibit Sierra Club-2.** The total running cost for existing coal units were estimated as the sum of the fuel cost and the fixed and variable O&M costs, expressed in $/MWh. Estimated running costs of the coal fleet in Kansas are given in **Exhibit Sierra Club-1.**

33. The costs shown in **Exhibit Sierra Club-1** do not include regular capital expenditures, such as boiler upgrades or major component replacements, or payments on initial capital expenditures. The assumptions do not factor in the cost of compliance with the new Clean Water Act effluent limitations guidelines nor do they include existing allowance costs or payments for sulfur dioxide (SO_2), mercury, or oxides of nitrogen (NO_X) in applicable trading regions. In addition, those costs also do not include the future costs of greenhouse gas emission permits, controls or regulation. Therefore, the costs shown may be considered conservative estimates.

New Environmental Control Cost Assumptions

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[9] The analysis compiles extensive data from the Energy Information Administration (EIA) to estimate operational characteristics of the coal fleet, and capital and O&M costs from several recent analyses of regulatory costs, including: (1) an October 2010 assessment of the reliability impacts of EPA regulations from the National Electric Reliability Council (NERC) (NERC 2010 Reliability Assessment); (2) assumptions for the IPM v4.1 model in the EPA's Regulatory Impact Assessment (RIA) of the Clean Air Transport Rule (CATR) (EPA CATR RIA); and assumptions for the Charles River Associates (CRA) MRA-NEEMS model in the Eastern Interconnection Planning Collaborative (EIPC) assessment of the impact of EPA regulations (EIPC 2010).

34. EPA regulations are expected to result in installation of emissions control technologies for SO_2, NO_X, and mercury, as well as water withdrawal reduction measures at plants which use once-through cooling and remediation for uncontrolled coal ash ponds. The Synapse analysis estimated the incremental future revenue requirements of adding environmental controls to the existing western coal fleet, where appropriate controls are not already available. These costs are categorized as an initial capital expenditure amortized over a period, and the fixed and variable O&M costs of operating the new equipment.

35. We estimated that current and pending regulations will require most, if not all, of the coal fleet to install and operate environmental controls for the protection of human health, ground and surface waters, and the environment. Synapse analysis showed that there is reasonable evidence that the coal fleet will require the following controls:

- FGD (flue gas desulfurization) for sulfur dioxide (SO_2) control and supplementary mercury capture,
- SCR (selective catalytic reduction) for oxides of nitrogen (NO_x) and ozone control,
- ACI (activated carbon injection) for mercury control,
- Baghouse for particulate capture,
- Wet cooling tower (closed-cycle cooling) to reduce water withdrawals, and
- Coal pond remediation and improved storage techniques

36. **Exhibit Sierra Club-3** shows current control environmental controls built at units of the coal fleet, according to 2008 EIA records. In Kansas,

- Holcomb 1, Lawrence 4 & 5, and units at the Jeffrey Energy Center are equipped with operational capable FGD units;
- No coal units are equipped with NO_X capture technologies (SCR or selective non-catalytic reduction [SNCR]);
- Only the Holcolmb 1 unit is equipped with a filter baghouse for particulate capture;
- The Riverton, Quindaro, Nearmean Creek, and La Cygne plants all use a form of once-through cooling;
- With the exception of the Quindaro plant, all other coal units retain a significant fraction of coal ash at the plant site in disposal ponds or landfills.

37. For the purposes of estimating future revenue requirements for existing coal units under a feasible, environmentally compliant regulatory regime, Synapse assumed that all existing coal units which do not have appropriate control technologies (as listed above) must be equipped with environmental retrofits to continue operation in a near-term year. The following financial analysis is a snapshot of an unspecified near-term future year

with the costs of these retrofits estimated and applied to the forward-going cost, holding fuel and O&M costs constant from 2008.

Financial Assumptions

38. For the purposes of this analysis, Synapse followed generic financial assumptions in the NERC 2010 Reliability Assessment. The study laid out four categories of ownership and estimated cost of capital recovery factor (CRF) assumptions as in Table 2 in Exhibit Sierra Club-2. Synapse assumed that the Holcomb plant has access to funding at a municipal cost of capital, as do the Quindaro and Nearman Creek units. The remaining units in this analysis are assumed to have a regulated IOU cost of capital. Environmental upgrades are assumed to be amortized over a 15 year period, while new power plants have a book life of 30 years.

SO_2 Pollution Controls: FGD Assumptions

39. Units in the fleet were considered to already have a valid and operational SO_2 control mechanism if the generator's primary boiler was reported to have an operational wet or dry FGD as of 2008. (See **Exhibit Sierra Club-3**.) The Synapse analysis follows FGD cost assumptions derived explicitly in the EPA CATR RIA, as stipulated by an associated Sargent & Lundy LLC analysis. The assumptions derive capital and O&M costs based on primarily capacity, but also unit heat rates, specifications on targeted emissions rates, and the cost of reagents and components. Default values for component costs and labor charges are listed in Table 3 of **Exhibit Sierra Club-2**.

40. A cost retrofit factor is used to adjust capital equipment and construction costs for site-specific difficulties or barriers to construction at an existing site, compared to greenfield construction cost. As defined in the Sargent & Lundy appendices to the EPA / IPM v4.1 model, "A retrofit factor that equates to difficulty in construction of the system must be defined. The costs herein could increase significantly for congested sites." A cost "retrofit factor" of 1.0 was assumed for FGD units. Units with pre-existing FGD were assumed to operate at 100% utilization, which, in this analysis, increases fixed and variable O&M costs.

NO_x Pollution Controls: SCR Assumptions

41. No unit in the study fleet has appropriate controls to draw NO_X out of the flue stream, reducing ozone pollution (see **Exhibit Sierra Club-3**); only existing SCR and SNCR units are considered adequate.

42. As with FGD cost assumptions, the Synapse analysis follows EPA CATR RIA to derive SCR costs, as stipulated by an associated Sargent & Lundy LLC analysis. Again, default values for component costs and labor charges are listed in Table 4 of **Exhibit Sierra Club-2**).

43. A cost "retrofit factor" of 1.0 was assumed for SCR units. Units with pre-existing SCR were assumed to operate at 100% utilization, which, in this analysis, increases their fixed and variable O&M costs. (The two Asbury units and Hawthorn 5 appear to have SCR installed.)

Mercury Pollution Controls: ACI Assumptions

44. There are no units in the fleet with dedicated mercury controls (activated carbon injection, ACI) as of 2008. (See **Exhibit Sierra Club-3.**) Under mercury control regulations, ACI would likely be required on all coal-fired units.

45. The capital and fixed and variable O&M costs of implementing mercury pollution controls were derived from the EIPC 2010 assessment.

Particulate Pollution Controls: Baghouse Assumptions

46. In the study fleet, only two units (Holcomb 1, KS, and Hawthorn 5, MO) are equipped with fabric filter baghouses to capture fine particulates. (See **Exhibit Sierra Club-3**). The remaining units are equipped with either electrostatic precipitators (ESP) or use other wet scrubbers for the purposes of reducing particulate emissions.

47. For the purposes of this analysis, electrostatic precipitators were considered insufficient control technologies for fine particulate capture, particularly with associated activated carbon injection for mercury control. It is anticipated that new mercury standards and tightening particulate air quality standards will require all coal units to be equipped with fabric filter baghouses.

48. The capital and fixed and variable O&M costs of implementing particulate pollution controls were derived from the EIPC 2010 assessment.

Reduction in Water Withdrawals and Discharges: Wet Cooling Tower Assumptions

49. Coal units making up approximately half of the capacity in this analysis utilize some form of once-through cooling, discharging cooling waters directly into lakes, streams, and multi-use reservoirs. The cooling pond of the La Cygne, KS, plant is the shoreline of the Linn County Park, and discharges six miles downstream to the Marais Des Cygnes National Wildlife Refuge. Similarly, the Montrose, MO, cooling pond is overlapped to a large extent by the Montrose Conservation Area. Other once-through cooling structures withdraw and discharge directly into moving rivers and streams.

50. For the purposes of this analysis, all once-through cooling systems which discharge into public waters were assumed to be subject to the 316(b) requirement, and to require cooling system retrofits to cooling towers or cells.

51. The costs of installing cooling towers were derived from the NERC 2010 Reliability Assessment. The assumed NERC cost curve, used in this analysis, is given in Figure 1 of **Exhibit Sierra Club-3**. No variable O&M costs were assumed.

Future Revenue Requirements with Environmental Controls

52. The total capital expenditures required to meet proposed environmental regulations for the study fleet in this analysis were estimated to be approximately $6 billion 2009$.

53. The estimates of future revenue requirements of generation were significantly higher given the full suite of capital and O&M expenditures required by expected environmental regulations. Estimated future revenue requirements for individual units in the fleet are given in **Exhibit Sierra Club-5**. Synapse estimated that the generation-

weighted average revenue requirement from coal units in this analysis could approximately double if all upgrades assumed in this analysis are implemented.

54. Alternatively, the forward-going cost of continuing to use coal-fired generators can be judged compared to alternatives, namely gas, wind, and energy efficiency, all of which are highly viable in Kansas. Synapse calculated each coal unit's economic merit, expressed as an environmentally compliant, forward-going cost of energy in $/MWh and compared that to the cost per MWh for each of four "replacement" technologies that could replace that coal unit: new gas combined cycle, existing gas combined cycle, new wind, and a conservatively priced energy efficiency program. For each existing coal unit, the environmentally compliant forward-going cost per MWh is shown on one row of the table in **Exhibit Sierra Club-6**. On the same row are shown the cost per MWh for each of the four alternative technologies were that technology used to displace just that one existing coal unit's output. Also shown on that row are the existing coal unit's cost differential from the most expensive alternative (the so-called "best case" for that existing coal unit) and the differential from the least expensive of alternative (the so-called "worst case" for that existing coal unit), as well as the difference between that coal unit's cost and the "best" and "worst" of those four alternatives. As may be seen from those results, four of the existing coal units in Kansas are estimated to be more expensive to run than even the most costly of the four alternatives (red figures in next to last column of **Exhibit Sierra Club-6**). Another three of the existing coal units were virtually tied with even the "worst" of the alternatives, being within one-half $/MWh in cost, easily within the range of uncertainty in this analysis. Only two of those existing coal units beat the least expensive alternative (black figures in the last column of **Exhibit Sierra Club-6**) and those did so only about one-half $/MWh.[10]

55. This analysis, while preliminary, clearly demonstrates evidence sufficient to support a conclusion that few, if any, of the existing coal units in the study fleet warrant spending money on the environmental upgrades they may be expected to need to keep running. There is some uncertainty in this analysis, mainly driven by questions about the cost of capital and recovery periods for environmental upgrades. However, it is clear that the cost of environmental retrofits should be considered for all pending regulations, on a multi-pollutant basis, rather than incrementally. In fact, not only is a comprehensive forward-going joint analysis of environmental upgrades for the utilities' entire coal fleet in the utilities urgently needed, that those long-term analyses need to examine the optimal retrofit / replacement schedules for each individual plant in context of the overall fleet and requirements. It is likely that some existing plants would not be part of a least cost resource portfolio for Kansas. Sierra Club provides these initial comparisons and analyses

[10] Replacement gas units were assumed to run at the same capacity factor as the coal unit being replaced; wind was assumed to run with a 39% capacity factor in Kansas; and energy efficiency was priced at 3.5 ¢/kWh ($35/MWh). New gas and wind units were priced according to assumptions in Table 8.2 of the EIA 2010 Annual Energy Outlook (AEO), and financial assumptions on the cost of capital are derived from the NERC 2010 Reliability Assessment with a 30-year amortization period. (See Table 2 in Exhibit Sierra Club--2.) Natural gas fuel costs were assumed to track the AEO 2010 delivered price forecast, levelized from 2015 to 2034. Finally, existing gas units were assumed to have the same fuel and O&M costs as new gas units, but without a cost of capital.

as a starting place, and reserves the right to add to and amend these analyses as more information becomes available.

III. Questions on Risk and Ratemaking Treatment (¶ 15 of Order)

56. In paragraph 15 of its Order, the Commission directed all parties to answer four "additional questions posed by the Commission" in their initial comments. Those questions relate to the bases for selection of resource options, to certain contingencies, and to the allocation of risk in resource decision making. The Sierra Club notes it can only answer certain of these questions conceptually at this time. Question (a) in paragraph 15 asks for the reasons why a utility has rejected certain options in its decision process; the other parties cannot respond with specificity until a utility has actually made such a choice and has provided sufficient documentation for us to assess the range of alternatives considered and the reasons for their rejection. Similarly, question (d) in that paragraph asks for "the forecasted effects on rates and on the financial performance of the respective company with traditional regulatory treatment and with predetermination treatment." This, too, is a fact-dependent question since the answer will depend on a variety of factors specific to the company and the plant, such as the current financial health of the utility, the relative sizes of the company's other rate base and the asset in question, and the other components of the company's cost of service. The Sierra Club will respond to the extent possible at this point in the proceeding, but wishes to emphasize that its ultimate position in any potential predetermination proceeding may evolve and differ from the points made here.

a) If a utility has selected a specific option (i.e., mothball, retrofit, decommission, and/or build new plant), why were other options rejected, not just why the option chosen was appropriate?

b) If a utility is successful in a predetermination proceeding, then it has shifted some risk from its shareholders to its ratepayers. Should the utility's stake in the generating facility, which was the subject of the predetermination proceeding, have different rate-making principles and treatment applied than would have been applied in a traditional rate case?

c) Will pre-approval reduce the utility's risk profile going forward? If so, should an adjustment be made to the utility's return on equity in connection with whatever preapproval is granted to the utility?

d) Given the broad selection of alternatives (i.e. mothball, retrofit, decommission, and/or build new) what are the forecasted effects on rates and on the financial performance of the respective company with traditional regulatory treatment and with predetermination treatment?

57. The Sierra Club supports the Commission's decision to pose these questions. The importance of requiring a demonstration by a utility that it has fully and properly evaluated alternatives to the investment it proposes, especially an investment for which it seeks a predetermination, cannot be overemphasized. The information and supporting documentation that the utility should provide to explain its approach has already been discussed above in these initial comments, especially under our response to the Commission's second fundamental question: "If the capacity and/or energy is needed,

then is the decision to retrofit a more economically efficient choice than decommissioning the existing plant and building a new plant?"

58. The Sierra Club supports the Commission's conclusion that "If a utility is successful in a predetermination proceeding, then it has shifted some risk from its shareholders to its ratepayers" and recommends that the Commission reserve the issue of how to reflect such risk shifting in ratemaking. The logical consequence of such a risk shift would necessarily be a change in the utility's risk profile from what it would have been absent predetermination. However, that would likely be a fact-specific determination.

IV. Additional Information (¶ 15 of Order)

61. The Commission invited all parties to provide any additional information a party believes the Commission should consider regarding the potential environmental upgrade requirements on the EGU s owned by KCP&L and Westar. Sierra Club offers the following observations at this time, but may have additional information that would be of use to the Commission at a later date.

62. It is possibile that a generating unit is necessary for system security due to transmission constraints, even if there appears to be excess capacity in the broader region. This is an issue that system operators pay close attention to. For example, in certain locations in New England, due to transmission constraints otherwise uneconomic plants have been retained in service. The Commission should consider such needs, as appropriate to local conditions in Kansas, but should not presume that retaining existing coal plants in service or upgrading them are the most economical ways to address any such constraints that may exist.

V. Conclusion

63. Sierra Club appreciates the opportunity to comment on the petition from Staff and supports the decision of the Commission to fully explore these challenging issues in electric utility resource planning. We look forward to responding to the filings by other parties and providing the Commission with additional information to ensure a robust dialog about these important issues.

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CERTIFICATE OF SERVICE

I hereby certify that on this 25th day of February, 2011 an original and seven copies of this Petition for Intervention were hand delivered to Susan K. Duffy, Executive Director, Kansas Corporation Commission, 1500 S.W. Arrowhead Road, Topeka, Kansas 66604, and that true and correct copies were deposited in the United States mail, first-class postage prepaid, properly addressed to:

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Exhibit SierraClub-1 **Operating Characteristics and Estimated Running Cost (2008)** **Synapse Energy Economics**

Plant Name	Unit	State	Nameplate Capacity (MW)	First Year of Operation	Plant Coal Heat Rate (mmbtu/MWh)	Capacity Factor (2008-2009)	Estimated Fuel Cost ($/MWh)	Estimated Fixed O&M Costs ($/kw yr)	Estimated Variable O&M Costs ($/MWh)	Estimated Running Cost in 2008 ($/MWh)
Riverton	7	KS	38	1950	13.47	47%	$23.69	$30.00	$5.00	**$35.98**
Riverton	8	KS	50	1954	13.47	69%	$23.69	$30.00	$5.00	[illegible]
Quindaro	ST1	KS	82	1965	10.86	73%	$16.57	$30.00	$5.00	**$26.25**
Quindaro	ST2	KS	158	1971	10.86	41%	$16.57	$21.00	$4.00	**$26.45**
Nearman Creek	1	KS	261	1981	11.11	62%	$19.99	$21.00	$4.00	**$27.83**
La Cygne	1	KS	893	1973	10.37	62%	$12.02	$18.00	$3.75	**$19.10**
La Cygne	2	KS	685	1977	10.37	78%	$12.02	$18.00	$3.75	**$18.40**
Holcomb	1	KS	349	1983	10.36	89%	$13.14	$18.00	$3.75	**$19.20**
Lawrence Energy Center	3	KS	49	1955	11.04	77%	$13.80	$30.00	$5.00	**$23.22**
Lawrence Energy Center	4	KS	600	1960	9.88	14%	$13.80	$18.00	$3.75	[illegible]
Lawrence Energy Center	5	KS	403	1971	11.04	70%	$13.80	$18.00	$3.75	**$20.46**
Tecumseh Energy Center	7	KS	82	1957	11.13	68%	$13.93	$30.00	$5.00	**$23.99**
Tecumseh Energy Center	8	KS	150	1962	11.13	71%	$13.93	$21.00	$4.00	**$21.31**
Jeffrey Energy Center	1	KS	720	1978	11.03	66%	$17.86	$18.00	$3.75	**$24.73**
Jeffrey Energy Center	2	KS	720	1980	11.03	71%	$17.86	$18.00	$3.75	**$24.49**
Jeffrey Energy Center	3	KS	720	1983	11.03	71%	$17.86	$18.00	$3.75	**$24.49**
Asbury	1	MO	213	1970	10.77	71%	$16.83	$21.00	$4.00	**$24.20**
Asbury	2	MO	19	1986	10.77	0%	[illegible]	$30.00	$5.00	[illegible]
Hawthorn	5	MO	594	1969	10.49	72%	$10.51	$18.00	$3.75	**$17.12**
Montrose	1	MO	188	1958	10.76	62%	$18.22	$21.00	$4.00	[illegible]
Montrose	2	MO	188	1960	10.76	65%	$18.22	$21.00	$4.00	**$25.89**
Montrose	3	MO	188	1964	10.76	70%	$18.22	$21.00	$4.00	**$25.62**
Iatan	1	MO	726	1980	10.05	63%	$9.71	$18.00	$3.75	**$16.70**

Table 1: Fixed and Variable O&M

Fixed and Variable O&M Assumptions (2010$)	
NERC EPA Analysis 2010 Assumptions	
MW	**Coal Fixed O&M ($/kw-yr)**
0	$30.00
100	$21.00
300	$18.00
MW	**Coal Variable O&M ($/MWh)**
0	$5.00
100	$4.00
300	$3.80

Table 2: Capital Recovery Factor Assumptions

Capital Recovery Factor (CRF) Assumptions					
		Environmental Upgrades		New Plant	
	Pre-Tax Cost of Capital	15 Year Book Life	Capital Recovery Factor (CRF)	30 Year Book Life	Capital Recovery Factor (CRF)
Merchant	17.50%	15	19.20%	30	17.60%
Regulated IOU	12.70%	15	15.20%	30	13.10%
Cooperative	7.00%	15	11.00%	30	8.10%
Municipal	6.00%	15	10.30%	30	7.30%

Table 3: FGD Cost Assumed Variables

Variable	Value
SO2 Rate (lbs/MWh)	1.5
Labor Rate ($/hr)	$60
Limestone cost ($/ton)	$15
Waste disposal cost ($/ton)	$30
Auxiliary Power Cost ($/kWh)	$0.06
Makeup water cost ($/1000 gal)	$1.00

Table 4. SCR Cost Assumed Variables

Variable	Value
NO_x Removal Factor	88%
NO_x Rate	21%
NO_x Removal Efficiency	70%
Urea Cost ($/ton)	310
Steam Cost ($/klb)	4

Figure 1: Cooling Tower Retrofit Cost

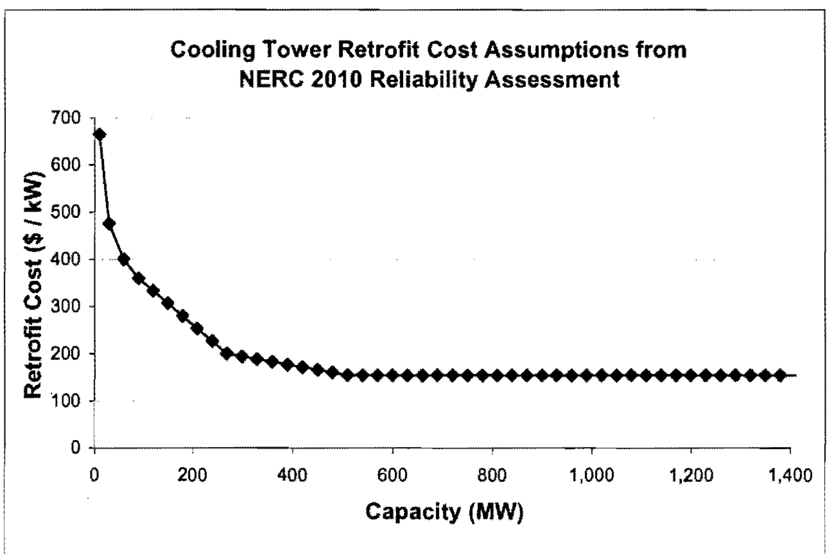

Exhibit SierraClub-3 **Existing Pollution Control Technologies (EIA 860, 2008) and Coal Ash Storage (EIA 923, 2008)** **Synapse Energy Economics**

Plant Name	Unit	State	Nameplate Capacity (MW)	Boiler SO_2 Control Processes	Boiler NO_X Control Processes	Boiler Mercury Control Processes	Boiler PM Control Processes	Boiler Cooling Type	Fraction of Coal Ash Impounded On-Site
Riverton	7	KS	38	-	Low Excess Air		Electrostatic precipitator	Once-Through Cooling	***Unknown
[illegible]	[illegible]	KS	[illegible]	[illegible]	Low Excess Air		[illegible]	[illegible]	[illegible]
Quindaro	ST1	KS	82	-	-		Electrostatic precipitator	Once-Through Cooling	0%
[illegible]	[illegible]	KS	[illegible]	[illegible]	Low NOx Burner		[illegible]	[illegible]	[illegible]
Nearman Creek	1	KS	261	-	Low NOx Burner		Electrostatic precipitator	Once-Through Cooling	19%
[illegible]	[illegible]	KS	[illegible]	*Venture type	Overfire Air		**Wet Scrubber	[illegible]	[illegible]
La Cygne	2	KS	685	-	Low NOx Burner		Electrostatic precipitator	Cooling Pond	52%
[illegible]	[illegible]	KS	348	Dry FGD	Low NOx Burner		Baghouse	[illegible]	[illegible]
Lawrence Energy Center	3	KS	49	-	-	**Electrostatic precipitator	Electrostatic precipitator	Recirculating Cooling Cell	100%
[illegible]	[illegible]	KS	600	Wet FGD & Venture Scrubber	[illegible]	**Wet Scrubber	**Wet Scrubber	[illegible]	[illegible]
Lawrence Energy Center	5	KS	403	Wet FGD & Venture Scrubber	-	**Wet Scrubber	**Wet Scrubber	Recirculating Cooling Cell	100%
[illegible]	7	KS	[illegible]	[illegible]	[illegible]	**Electrostatic precipitator	[illegible]	[illegible]	[illegible]
Tecumseh Energy Center	8	KS	150	-	-	**Electrostatic precipitator	Electrostatic precipitator	Recirculating Cooling Cell	36%
[illegible]	[illegible]	KS	720	Wet FGD (Standby)	[illegible]	**Electrostatic precipitator, Wet Scrubber	[illegible]	[illegible]	[illegible]
Jeffrey Energy Center	2	KS	720	Wet FGD (Standby)	-	*Electrostatic precipitator, Wet Scrubber	Electrostatic precipitator	Recirculating Cooling Cell	35%
[illegible]	[illegible]	KS	720	Wet FGD (Standby)	[illegible]	*Electrostatic precipitator, Wet Scrubber	[illegible]	[illegible]	[illegible]
Asbury	1	MO	213	-	SCR, Overfire Air	**Electrostatic precipitator	Electrostatic precipitator	Recirculating Cooling Cell	56%
[illegible]	[illegible]	MO	[illegible]	[illegible]	SCR, Overfire Air	**Electrostatic precipitator	[illegible]	[illegible]	[illegible]
Hawthorn	5	MO	594	Dry FGD	SCR, Overfire Air, Low NOx Burner		Baghouse	Once-Through Cooling	9%
[illegible]	[illegible]	MO	188	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]
Montrose	2	MO	188	-	-		Electrostatic precipitator	Cooling Pond	60%
[illegible]	[illegible]	MO	188	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]
Iatan	1	MO	726	-	Low NOx Burner		Electrostatic precipitator	Once-Through Cooling	28%

*Plant reports Venture-type scrubber to EIA (2008) and "wet limestone" scrubber to EPA (2009)
**Technologies have ancillary benefits for PM and mercury control, but are not designed for exclusive PM or mercury control
***Plant did not report coal ash disposition to EIA in 2008; arial photographs (Google Earth) indicate significant on-site coal storage

Exhibit SierraClub-4 | **Estimated Environmental Upgrade Capital Expendatures (Million 2009$)** | **Synapse Energy Economics**

Plant Name	Unit	State	FGD Total Project Cost (Million $)	SCR Total Project Cost (Million $)	ACI Capital Cost (Million $)	Baghouse Capital Cost (Million $)	Wet Cooling Tower Capital Cost (Million $)	Total Capital Expendatures (Million $)
Riverton	7	KS	$46.7	$14.4	$2.2	$18.8	$17.8	**$99.9**
[redacted]								
Quindaro	ST1	KS	$73.9	$22.1	$2.4	$27.8	$32.6	**$158.8**
[redacted]								
Nearman Creek	1	KS	$171.6	$57.6	$2.9	$49.7	$59.2	**$341.0**
[redacted]								
La Cygne	2	KS	$332.0	$123.6	$3.4	$80.4	$106.2	**$645.6**
[redacted]								
Lawrence Energy Center	3	KS	$51.7	$15.2	$2.3	$21.5		**$90.6**
[redacted]								
Lawrence Energy Center	5	KS		$82.7	$3.1	$61.7		**$147.5**
[redacted]								
Tecumseh Energy Center	8	KS	$115.5	$36.6	$2.7	$37.6		**$192.4**
[redacted]								
Jeffrey Energy Center	2	KS		$136.2	$3.4	$82.5		**$222.1**
[redacted]								
Asbury	1	MO	$146.2		$2.8	$44.8		**$193.9**
[redacted]								
Hawthorn	5	MO			$3.3		$92.1	**$95.4**
[redacted]								
Montrose	2	MO	$133.8	$42.8	$2.8	$42.1	$52.6	**$274.1**
[redacted]								
Iatan	1	MO	$341.4	$126.6	$3.4	$82.8	$112.5	**$666.7**

Total Costs in Kansas	**$4,181.4**
Total Costs for All Plants in Analysis	**$6,060.0**

Exhibit SierraClub-5 **Estimated Impact of Environmental Upgrades on Forward-Going Cost ($/MWh)** **Synapse Energy Economics**

Plant Name	Unit	State	Estimated Running Cost in 2008 ($/MWh)	Incremental Cost of FGD Upgrade ($/MWh)*	Incremental Cost of SCR Upgrade ($/MWh)*	Incremental Cost of ACI Upgrade ($/MWh)*	Incremental Cost of Baghouse Upgrade ($/MWh)*	Incremental Cost of Cooling Tower Upgrade ($/MWh)*	Forward-Going Cost ($/MWh)
Riverton	7	KS	**$36.0**	$63.1	$16.7	$3.2	$19.0	$17.6	**$155.6**
[redacted]									
Quindaro	ST1	KS	**$26.3**	$22.1	$5.6	$1.1	$5.6	$6.4	**$67.0**
[redacted]									
Nearman Creek	1	KS	**$27.8**	$18.0	$5.1	$0.7	$3.7	$4.3	**$59.5**
[redacted]									
La Cygne	2	KS	**$18.4**	$15.0	$4.8	$0.5	$2.7	$3.5	**$44.9**
[redacted]									
Lawrence Energy Center	3	KS	**$23.2**	$33.2	$8.5	$1.7	$10.1	$0.0	**$76.7**
[redacted]									
Lawrence Energy Center	5	KS	**$20.5**	$4.8	$5.9	$0.6	$3.9	$0.0	**$35.6**
[redacted]									
Tecumseh Energy Center	8	KS	**$21.3**	$25.1	$7.0	$0.9	$6.3	$0.0	**$60.6**
[redacted]									
Jeffrey Energy Center	2	KS	**$24.5**	$4.5	$5.4	$0.5	$2.8	$0.0	**$37.8**
[redacted]									
Asbury	1	MO	**$24.2**	$22.3	$0.9	$0.8	$5.3	$0.0	**$53.4**
[redacted]									
Hawthorn	5	MO	**$17.1**	$4.5	$0.8	$0.5	$0.1	$3.8	**$26.7**
[redacted]									
Montrose	2	MO	**$25.9**	$24.8	$7.0	$0.9	$6.1	$7.5	**$72.1**
[redacted]									
Iatan	1	MO	**$16.7**	$17.2	$5.5	$0.5	$3.2	$4.3	**$47.5**
Weighted Average (by Gen)			**$21.9**						**$47.6**

*Includes amortized capital expendatures, as well as fixed and variable O&M costs. Fixed costs distributed over net generation in 2008. Assumes FGD, SCR, ACI, baghouse, and cooling towers operate at 100% utilization during operating hours.

Exhibit SierraClub-6 | **Economic Merit of Existing Coal Fleet Relative to Alternative Supply and Demand Side Options ($/MWh)** | **Synapse Energy Economics**

Plant Name	Unit	State	Capacity Factor, Average 2008-2009	Forward-Going Cost for Existing Coal Units ($/MWh)*	Estimated All-in Cost of a New Natural Gas CC @ Capacity Factor ($/MWh)	Estimated Cost of Existing Gas CC @ Capacity Factor ($/MWh)	Estimated Cost of Wind @ 39% Capacity Factor ($/MWh)	Cost of Energy Efficiency ($/MWh)	Best Case Economic Merit ($/MWh)	Worst Case Economic Merit ($/MWh)
Riverton	7	KS	47%	**$155.6**	$86.3	$55.0	$84.6	$35.0	**($69.3)**	**($120.6)**
Riverton	8	KS	69%	**$108.9**	$75.2	$54.0	$84.6	[illegible]	[illegible]	[illegible]
Quindaro	ST1	KS	73%	**$67.0**	$65.1	$53.9	$51.1	$35.0	**($2.0)**	**($32.0)**
Quindaro	ST2	KS	41%	**$81.3**	$75.5	$55.5	[illegible]	[illegible]	[illegible]	[illegible]
Nearman Creek	1	KS	62%	**$59.5**	$67.4	$54.3	$51.1	$35.0	**$7.9**	**($24.5)**
La Cygne	1	KS	62%	**$49.7**	$78.1	$54.3	$84.6	$35.0	**$35.0**	[illegible]
La Cygne	2	KS	78%	**$44.9**	$72.6	$53.8	$84.6	$35.0	**$39.8**	**($9.9)**
Holcomb	1	KS	89%	**$27.8**	$63.7	$53.6	$55.7	$35.0	**$36.0**	[illegible]
Lawrence Energy Center	3	KS	77%	**$76.7**	$72.8	$53.8	$84.6	$35.0	**$8.0**	**($41.7)**
Lawrence Energy Center	4	KS	44%	**$144.3**	$168.0	$62.4	$84.6	$35.0	**$23.7**	[illegible]
Lawrence Energy Center	5	KS	70%	**$35.6**	$74.8	$54.0	$84.6	$35.0	**$49.0**	**($0.6)**
Tecumseh Energy Center	7	KS	68%	**$74.1**	$75.8	$54.1	$84.6	$35.0	**$10.6**	[illegible]
Tecumseh Energy Center	8	KS	71%	**$60.6**	$74.7	$54.0	$84.6	$35.0	**$24.1**	**($25.6)**
Jeffrey Energy Center	1	KS	66%	**$38.8**	$76.5	$54.2	$84.6	[illegible]	[illegible]	[illegible]
Jeffrey Energy Center	2	KS	71%	**$37.8**	$74.5	$54.0	$84.6	$35.0	**$46.9**	**($2.8)**
Jeffrey Energy Center	3	KS	71%	**$37.8**	$74.5	$54.0	$84.6	[illegible]	**$46.9**	[illegible]
Asbury	1	MO	71%	**$53.4**	$74.6	$54.0	$84.6	$35.0	**$31.2**	**($18.4)**
Asbury	2	MO	0%	**$29,198.0**	$4,725.0	$474.0	[illegible]	[illegible]	[illegible]	[illegible]
Hawthorn	5	MO	72%	**$26.7**	$74.4	$54.0	$84.6	$35.0	**$57.9**	**$8.3**
Montrose	1	MO	62%	**$74.5**	$77.9	$54.3	$84.6	[illegible]	[illegible]	[illegible]
Montrose	2	MO	65%	**$72.1**	$76.6	$54.2	$84.6	$35.0	**$12.5**	**($37.1)**
Montrose	3	MO	70%	**$68.5**	$74.8	$54.0	[illegible]	[illegible]	[illegible]	[illegible]
Iatan	1	MO	63%	**$47.5**	$77.4	$54.2	$84.6	$35.0	**$37.2**	**($12.5)**

THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of a General Investigation Into) KCP&L and Westar Generation Capabilities,) Including as these Capabilities May Be) Affected by Environmental Requirements.)	Docket No. 11-GIME-492-GIE

AFFIDAVIT OF WILLIAM STEINHURST IN SUPPORT OF INITIAL COMMENTS OF THE SIERRA CLUB

STATE OF VERMONT,)
) SS:
COUNTY OF WASHINGTON,)

William Steinhurst, being first duly sworn, deposes and states:

1. I, William Steinhurst have my business address at 32 Main St., #394, Montpelier, Vermont 05602. I have personal knowledge of the matters described in this Affidavit. I submit this Affidavit in support of the Sierra Club's Initial Comments in the above captioned matter.
2. I have been a Senior Consultant with Synapse Energy Economics, Inc., 22 Pearl St., Cambridge, Massachusetts 02139, for the last seven years.
3. I have been retained by the Sierra Club to assist it in the above captioned matter.
4. I have over twenty-nine years of experience in utility regulation and energy policy, including work on renewable portfolio standards and portfolio management practices for default service providers and regulated utilities, green marketing, distributed resource issues, economic impact studies, and rate design. Prior to joining Synapse, I served as Planning Econometrician and Director for Regulated Utility Planning at the Vermont Department of Public Service, the State's Public Advocate and energy policy agency.
5. I have provided consulting services for various clients, including the Connecticut Office of Consumer Counsel, the Illinois Citizens Utility Board, the California Division of Ratepayer Advocates, the D.C. and Maryland Offices of the Public Advocate, the Delaware Conservation Law Foundation, the Regulatory Assistance Project, the National Association of Regulatory Utility Commissioners (NARUC), the National Regulatory Research Institute (NRRI), American Association of Retired Persons (AARP), The Utility Reform Network (TURN), the Union of Concerned Scientists, the Northern Forest Council, the Nova Scotia Utility and Review Board, the U.S. EPA, the Conservation Law Foundation, the Sierra Club, the Southern Alliance for Clean Energy, the Oklahoma Sustainability Network, the Natural Resource Defense Council (NRDC), Illinois Energy

Office, the Massachusetts Executive Office of Energy Resources, the James River Corporation, and the Newfoundland Department of Natural Resources. I hold a B.A. in Physics from Wesleyan University and an M.S. in Statistics and Ph.D. in Mechanical Engineering from the University of Vermont.

6. I was the lead author or co-author of Vermont's long-term energy plans for 1983, 1988, and 1991, as well as the 1998 report *Fueling Vermont's Future: Comprehensive Energy Plan and Greenhouse Gas Action Plan* and Synapse's study *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*. In 2008, I was commissioned by the National Regulatory Research Institute to write *Electricity at a Glance*, a primer on the industry for new public utility commissioners and, in 2011, to update that primer for NRRI.
7. Synapse Energy Economics, Inc., is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission staff, state attorneys-general, environmental organizations, federal government and utilities. A complete description of Synapse is available at our website, www.synapse-energy.com.
8. I prepared, supervised the preparation of, or assisted in the preparation of the following portions of the Sierra Club's Initial Comments in the above captioned proceeding: Sections II, III and IV. WS
9. The information and opinions contained in those portions of the Sierra Club's Initial Comments described in paragraph 8, immediately above, are true and correct to the best of my personal and professional knowledge. This affidavit is made under oath.

FURTHER AFFIANT SAITH NAUGHT.

William Steinhurst

WILLIAM STEINHURST, AFFIANT

STATE OF VERMONT,)
) ss:
COUNTY OF WASHINGTON)

Subscribed and sworn to before me on this 24th day of February, ~~2010~~ 2011.

Notary Public

My appointment expires:

ANNABEL L GONYAW
NOTARY PUBLIC, VERMONT
~~MY COMMISSION EXPIRES~~ FEB. 10, 2015

THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of a General Investigation Into) KCP&L and Westar Generation Capabilities,) Including as these Capabilities May Be) Affected by Environmental Requirements.)	Docket No. 11-GIME-492-GIE

AFFIDAVIT OF JEREMY FISHER IN SUPPORT OF INITIAL COMMENTS OF THE SIERRA CLUB

STATE OF MASSACHUSETTS,)
) SS:
COUNTY OF MIDDLESEX,)

Jeremy Fisher, being first duly sworn, deposes and states:

1. I, Jeremy Fisher, have been a Senior Scientist with Synapse Energy Economics, Inc., 22 Pearl St., Cambridge, Massachusetts 02139, for the last three years. I have personal knowledge of the matters described in this Affidavit. I submit this Affidavit in support of the Sierra Club's Initial Comments in the above captioned matter.
2. I have been retained by the Sierra Club to assist it in the above captioned matter.
3. I have ten years of applied experience as a geological and climate scientist, as well as three years of working within the energy planning sector, including work on integrated resource plans, long-term planning for states and municipalities, modeling social and environmental externalities, and electrical system dispatch. Prior to joining Synapse, I worked as a postdoctoral researcher at the University of New Hampshire and Tulane University on the impacts of Hurricane Katrina.
4. I have provided consulting services for various clients, including the U.S. EPA, the National Association of Regulatory Utility Commissioners (NARUC), the California Energy Commission (CEC), the California Division of Ratepayer Advocates, the State of Utah Energy Office, the National Association of State Utility Consumer Advocates (NASUCA), the National Rural Electric Cooperative Association (NRECA), the State of Alaska, the Union of Concerned Scientists (UCS), the Sierra Club, the National Resources Defense Council (NRDC), the Environmental Defense Fund (EDF), the Stockholm Environment Institute (SEI), and the Civil Society Institute. I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and an Sc.M. and Ph.D. in Geological Sciences from Brown University
5. I was a principal or co-lead on papers examining the impact of renewable energy and energy efficiency on emissions for the State of California, the State of Utah, the State of

Connecticut, and the US EPA. I have led, or am leading, projects examining IRP processes and alternative resource plans in Michigan, the City of Los Angeles, Nevada, Utah, Wyoming, and Alaska.

6. Synapse Energy Economics, Inc., is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission staff, state attorneys-general, environmental organizations, federal government and utilities. A complete description of Synapse is available at our website, www.synapse-energy.com.
7. I prepared, supervised the preparation of, or assisted in the preparation the following portions of the Sierra Club's Initial Comments in the above captioned proceeding: Section II.C, paragraphs 24 through 55, and Exhibits SierraClub 1 through 6.
8. The information and opinions contained in those portions of the Sierra Club's Initial Comments described in paragraph 8, immediately above, are true and correct to the best of my personal and professional knowledge. This affidavit is made under oath.

FURTHER AFFIANT SAITH NAUGHT.

JEREMY FISHER, AFFIANT

STATE OF MASSACHUSETTS,)
) ss:
COUNTY OF MIDDLESEX)

Subscribed and sworn to before me on this 24th day of February, 2011.

Notary Public

My appointment expires: October 8, 2015

REBECCA ANNE KEANE
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
October 8, 2015