MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of an Investigation of the Cost to Missouri's Electric Utilities Resulting from Compliance with Federal Environmental Regulations

Case No. EW-2012-0065

Comments to Staff

On Behalf of
Sierra Club

December 27, 2011

1. INTRODUCTION

These comments are submitted in response to the Commission's Order Opening an Investigation into the Cost of Compliance with Federal Environmental Regulations dated August 30, 2011. The comments were prepared by the Sierra Club and by Lucy Johnston from Synapse Energy Economics with assistance from Jeremy I. Fisher, Ph.D, Tommy Vitolo, Ph.D, Kenji Takahashi, Alice Napoleon, Tyler Comings and Patrick Knight from Synapse Energy Economics. 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.

2. OVERVIEW

Many states and utilities are managing large coal fleets and are faced with task of ensuring multiple policy objectives (economic, environmental, reliability) are met. EPA is expressly pursuing a multi-pollutant approach in developing regulations in order to facilitate comprehensive compliance planning for companies. In January 2010, EPA announced its intention to ensure better air quality, and promote a cleaner and more efficient power sector and have strong but achievable reduction goals for SO_2, NO_X, mercury, and other air toxics.[1] EPA Administrator Jackson has emphasized the agency's efforts to take a multi-pollutant sector-based approach to regulation in order to provide certainty and clarity.[2] EPA regulations for these pollutants have been under development

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[1] Lisa P. Jackson, Seven Priorities for EPA's Future, available at http://blog.epa.gov/administrator/2010/01/12/seven-priorities-for-epas-future/. Accessed 4/8/11.

[2] Lisa Jackson, Remarks on the 40th Anniversary of the Clean Air Act, As Prepared; September 14, 2010. Available at

for years. Existing coal units are subject to EPA regulations under the Clean Air Act (CAA), the Clean Water Act (CWA), and the Resource Conservation and Recovery Act (RCRA), among other statutes, as shown in the table below

The costs to comply with an individual regulation or requirement should not be considered in isolation. Neither a utility nor the Commission should be content with a piecemeal approach to considering the cost-effectiveness of compliance options; instead a utility should consider all reasonable forward-going risks, including regulatory risks, for all plants and all plans, and the Commission should ensure that it has sufficient detailed information to reach a decision in these complex matters. It is important to consider the full scope of upcoming regulations to develop a long-term resource plan that makes sense from a customer impact perspective. Considering retrofit investments one by one, as final regulations are issued, will result in a subpar decision-making process where ratepayers might fund retrofits that appear cost-effective when considered individually, but that combined are more expensive than other available options and could render some existing generating units uneconomic.

EPA regulations could have an impact on a substantial portion of the coal fleet in Missouri, especially when coupled with a carbon price. Synapse has done an analysis of Missouri resources, and potential costs of emissions mitigation. Synapse's initial evaluation of publicly available data for the Missouri coal fleet shows when compliance with EPA regulations is evaluated 17.2% of coal capacity is vulnerable (deemed high risk or where retirement is most economic).[3]

Missouri cannot afford a case-by-case, retrofit-by-retrofit approach to evaluating utilities' decisions on how to achieve compliance. Regulatory mandates will inevitably inform utilities' decisions as they make future resource allocations to meet customer demand.

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http://yosemite.epa.gov/opa/admpress.nsf/a883dc3da7094f97852572a00065d7d8/b6210c1d1d49b7a4852577fb006f435a!OpenDocument. Accessed 4/8/11.

[3] This triage data is discussed in more detail later in these comments. The data is conservative in that it does not include the cost of controlling coal combustion residuals or wastewater effluent. These added compliance requirements are being considered by EPA and will likely be implemented over the next 5 years.

Given the sheer number and wide coverage of these mandates, it will be essential that, for future planning purposes, the Commission and the utilities consider their potential impact in a cohesive, rather than singular, case-by-case basis.

The potential impact of the combination of regulations highlights the need for comprehensive and forward-looking planning. To support good decision-making, it is essential to understand the full forward-going costs that utilities will face, and that they will seek to pass along to ratepayers. Sierra Club urges the Commission to ensure that it receives the information necessary to make these determinations and that the appropriate regulatory proceedings are available to permit sound decision-making in the interests of ratepayers and consistent with state and federal policy objectives. Strong planning mechanisms and regulatory proceedings will mitigate potential impacts and enable a smooth transition to a 21st century resource mix.

3. PRINCIPLES OF GOOD PLANNING AND EVALUATION OF INVESTMENT DECISIONS

Electric generating units in Missouri and owned by Missouri utilities face significant compliance obligations and costs associated with current and emerging regulatory programs. Understanding current and emerging regulations is essential to understanding the full forward-going costs that utilities 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 and replacement with more economic resource options.

The U.S. Environmental Protection Agency (EPA) is poised to promulgate a series of rules that will apply to the fleet of generating units in Missouri. The following table provides an overview of the rules. The rules are grouped for discussion under relevant federal statutes, but the state of Missouri will take the lead in implementing many of these regulations through state programs. This series of environmental and public-health based rules and their application to specific units requires thoughtful analysis.

Table 1: Summary of existing and emerging regulations

Law	Regulation	Applicability to generating units	Time period	Regulated Pollutants & potential controls
Clean Air Act	Regional Haze	BART-eligible EGUs in Missouri/Kansas	Final. Up to 5 years from SIP determination	SO_2 and NO_x. Controls include scrubbers and SCR.
	Cross-State Air Pollution Rule.	Electric generating units in Missouri/Kansas	Final rule 2011. Implementation 2012 and 2014.	SO_2 and NO_x. Controls include scrubbers, SCR, sorbent injection, SNCR, low-nox burners.
	Air Toxics	Units that (i.e. >10 t/yr of one pollutant or >25 t/yr of combined pollutants)	Proposed 03-2011 Final December 2011 Implementation 3 years after final rule, and no later than 2015	Includes acid gases, mercury, non-mercury metals. Potential controls include wet scrubbers, sorbent injection, 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, sorbent injection, SCR, baghouses.
Clean Water Act	Cooling Water regulations for existing plants	All existing power plants	Proposed 2011 Final July 2012 Implementation 5-8 years.	Plants using once through cooling may need to retrofit to closed-cycle cooling to reduce impingement and entrainment.
	Effluent limitation guidelines - update	All plants requiring CWA discharge permit	Proposed mid 2012 Final 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 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	Rule is final and applicable.	Six greenhouse gases Case-by-case determination, may include cleaner fuel, controlling fugitive emissions, carbon sequestration, boiler efficiency
	NSPS for EGUs	Existing plants with modifications	Final 2012 Implementation 3-4 years after final (2016?)	To be determined

The above table shows the potential synergistic magnitude of existing and proposed regulatory requirements. These long-overdue and much-needed public health and environmental protections will inevitably inform utilities decisions as they make future resource allocations to meet customer demand. Given the number and coverage of these regulations, it is essential that the Commission and the utilities consider the impact of these regulations in a cohesive way rather than on a rule-by-rule basis.

Sierra Club urges the commission to use caution when a regulated utility requests approval to "rush to retrofit," whether through an IRP, a rate case, or other proceeding. The commission should think beyond a simple selection among alternative power plant retrofits to determine the optimal configuration for meeting regulatory requirements over the long term. In these cases, "optimal" considers costs and a range of future risks associated with a utility's proposed compliance plan. 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.

A step-wise, consistent decision-making process is necessary 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.

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 should 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,
>
> (2) an objective analysis of how those uncertainties and risks affect 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

The scope of Commission consideration and any guidance it provides to regulated utilities should include all material factors that affect resource needs and selection. Retrofit technologies and all other available resource options should be 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 Missouri requirements.[4] 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.

The retirement of coal units facing expensive capital investments may represent a cost-effective path for the benefit of ratepayers and the public. However, there is no reason to believe, without additional planning, that a one for one replacement of coal plants with natural gas combined cycle units represents a least-cost mechanism for meeting the electric needs of Missouri ratepayers. When considering retirement of existing coal units,

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[4] 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.

companies must consider a complete range of options for a replacement portfolio, including renewable energy, cost-effective energy efficiency, market purchases, and new gas-fired power plants. In some circumstances, converting existing coal units to natural gas is likely to be less expensive than continuing the operation of coal plants that require, in addition to investments to achieve compliance, routine expenditures for the maintenance of an aging fleet. However, converting existing infrastructure to utilize natural gas should be evaluated as just one potential mechanism in a cost-effective energy portfolio.

Compliance decisions will require determining whether retrofitting is a more economically efficient choice than decommissioning an existing plant and relying on existing capacity or procuring new resources (including possibly building a new plant). 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 detail the relevant information, methodologies and supporting documentation the utilities must provide to enable adequate review. These requirements should be based on national best practices for utility resource planning as well as relevant Missouri 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. The Commission should issue rules or guidance that clearly articulate the criteria and required documentation for the analysis described above.

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. 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.

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 would be sound public policy for the Commission to require such resource plans. The Commission should also have in mind assessment of 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.

In its review of utility proposals 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 power plants in light of a rapidly changing landscape that disfavors coal, and that compare those costs to the variety of alternatives available to Missouri utilities. Underlying these considerations are the principles of prudency that apply to ratemaking, including the obligation for ongoing reassessment of avoidable costs.

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.

4. COAL FLEET PLANNING

An assessment of the existing and potential economic customer impacts of different options such as continued use of coal and installation of emissions control, use of available gas capacity, and development of other resources such as renewables and energy efficiency requires a comprehensive planning process (and/or comprehensive investment review) that takes into account the full range of potential compliance costs, assessment of financial risks, as well as costs of alternatives. Given the EPA initiative to issue a comprehensive set of regulations governing multiple pollutants – which will not be fully addressed by installing scrubbers or any one emission control technology - it is important to consider the full scope of upcoming regulations to develop a long-term resource plan that makes sense from a customer impact perspective. Investment in compliance activities with high capital costs is particularly risky when additional regulations are near certain but the specifics and not yet final. Finally, for continued operation of carbon intensive coal-fired facilities, decision makers must always consider the possibility of a cost on carbon emissions. This highlights the importance of a comprehensive planning process and holistic assessment of costs of alternatives.

One option that the Commission could consider in the current period of rapid and important in environmental regulation, an "Integrated Environmental-Compliance Planning" (IECP) approach that Sierra Club has also proposed in Oklahoma in the OCC's Inquiry to Examine Current and Pending Federal Regulation and Legislation.[5] The IECP can provide the system-wide perspective the Commission needs to inform future pre-approval determinations, while avoiding the time-consuming process of reviewing all the statewide issues from scratch in each pre-approval case.

Missouri does have IRP rules, however, IRP has several shortcomings in the context of IECP, including the following:

- The utilities file IRPs individually. Holistic IECP would include a statewide approach to such issues as the availability of existing surplus capacity, off-system purchases, assessment of wind potential and transmission requirements, gas availability, and other common opportunities and constraints.
- Each utility's IRP is based on its own assessment of capital and fuel costs. IECP would logically involve a single set (or range) of cost assumptions.
- Traditional IRPs are oriented around the utility's development and explanation of its preferred plan. In order to make informed decisions on the pending important and expensive decisions pending, the Commission will need a full understanding of statewide challenges and opportunities, including multiple paths for complying with environmental requirements and moving forward. Focusing on a utility-preferred plan would be a distraction from the Commission's primary goals in this process, which should be to gather the information necessary to act expeditiously

[5] Sierra Club;"Response to Issues and Questions On Behalf of Sierra Club On the Topic of Fuel-Source-Related Issues July 18, 2011;"Submitted in Oklahoma Corporation Commission Cause No. PUD 201100077

on resource-acquisition decisions (including environmental retrofits) as they arise and to provide guidance to the utilities regarding the resources that the Commission believes they should be pursuing.

- IRPs have traditionally assumed that existing resources will continue to operate through fixed retirement dates and have thus focused on the gap between need and existing resources. In the current situation, the plan must also assess whether operation of particular existing resources effectively meets reliability, cost, environmental or other criteria, compared to alternatives. The costs of retrofitting and continuing to operate these generators must be compared to the costs of existing underutilized natural-gas capacity, new combined-cycle capacity, wind, other renewables, demand response, and energy efficiency.

- The IRPs are primarily an opportunity for the utility to present its preferred plan to the Commission, with very limited input from other parties. In contrast, the IECP process must involve greater transparency in the utility's inputs and analysis (particularly through provision of more detail than required in the IRPs, and multiple rounds of discovery) and greater input from other parties, including adequate time for review of utility data and analyses, filing of direct and rebuttal testimony, and adjudicatory hearings.

In evaluating continued operation of existing plants, it is critical for companies to consider a reasonable range and intensity of risks and uncertainties, particularly those associated with environmental regulation. As discussed above these include costs related to the following:

- reducing carbon emissions;

- reducing NOx emissions to reduce smog ozone levels to meet current and future standards,

- reducing emissions of NOx and SO_2 to control haze and particulate pollution, including future air quality rules for particulates,

- reducing emissions of mercury and other hazardous air pollutants,

- controlling coal combustion waste under both waste rules and water-quality rules,[6] and
- limiting the use of cooling water to protect fish and other organisms.

Responding to these requirements piecemeal will result in inefficient and unnecessarily expensive decisions. The Commission should require utilities to provide the anticipated costs and the potential risks of existing and emerging regulations for the whole range of pollutants in utility evaluations of their investment proposals. Given the capital-intensive and long-lived nature of investments in the electric industry, if the final form or timing of a regulation is unknown, the analysis should include both an expected value of the cost of compliance and the range of plausible costs.

Colorado has enacted a form of IECP, in the form of a legislative mandate for “emission reduction plans” under House Bill (HB) 10-1365. The Colorado PSC describes that legislation as “At the highest level, HB 10-1365 reflects the General Assembly’s belief that Colorado will realize significant economic and public health benefits by addressing emissions from front-range coal-fired power plants in a coordinated fashion. Having made this determination that a comprehensive emission reduction strategy is in the public interest, the legislature tasked the Commission and other state agencies with vetting and shaping the plans proposed by regulated electric utilities.”[7] The modified plan eventually ordered by the Colorado PUC included the retirement of five coal units in 2011–2017, conversion of two coal units to gas in 2014 and 2017 (although Public Service Colorado was also ordered to further study retirement options in its next IRP), and installation of controls on three units in 2014–2016. This particular review was focused on reducing

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[6] Continuation or repetition of the current drought may increase pressure on the coal plants to reduce water consumer from cooling towers, as well.

[7] Final Order in Docket No. 10M-245E, December 9, 2010, ¶2.

NOx emissions, but the PUC also considered the effects of the alternatives on emissions of SO_2, particulates, mercury and carbon.[8]

Over the next few years, the Missouri PSC should conduct IECP evaluations separately from the normal IRP cycle, to focus primarily on the fate of the units that face the earliest and most expensive emission-reduction requirements.

There is a clear need for the Commission to have sufficient information to evaluate the merits of requests for IRP approval or rate increases in light of the alternatives available. . It is not a foregone conclusion that cleaning up a dirty power plant is the best alternative for reducing emissions. Existing units do not exist in a vacuum, and the economics of continued operation depend on the availability of system-wide resource alternatives. The Commission needs this larger context to determine whether the investments associated with a utility's compliance strategy are in the best interests of ratepayers. The IECP can provide the system-wide perspective in support of the Commission's pre-approval determinations, while avoiding the time-consuming process of reviewing all the statewide issues from scratch in each pre-approval case.

In order to illustrate the potential magnitude of compliance costs, we have estimated capital expenditures for compliance with upcoming regulations using readily available public information. We estimate total capital expenditures of about $11 billion to install the full suite of modern pollution control technologies on Missouri coal units operating above a 12% capacity factor to comply with both existing and many impending regulations (see Table 3), including cooling towers on the once-through cooled Sooner units. These investments are significant, and should not be pursued without careful and comprehensive planning that gives full consideration to a wide range of supply and demand alternatives, as well as new and underutilized existing resources.

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[8] "The Commission observes that EPA regulation of greenhouse gasses is currently underway, future regulation in some form is highly likely, and that those regulations will eventually impose costs on a utility's greenhouse gas emissions. Therefore, while we do not adopt a specific future cost per ton in evaluating the proposed scenarios, we consider each scenario's carbon emissions reductions, as well as its sensitivity to carbon prices." (Final Order in Docket No. 10M-245E, ¶92)

Table 2 on the next page shows projected capital expenditures for Missouri coal units. Table 3, on the subsequent page, compares the forward-going costs ($/MWh) of coal units compared with alternative supply and demand side options (for units operating at a capacity factor higher than 12%).

Beyond the costs listed in the tables below, Missouri coal units could face additional compliance costs associated with revision of the NAAQS, compliance with effluent limitation guidelines restricting liquid releases from coal wastes (which could entail water treatment), rules on managing coal combustion residuals (ash) for new and existing coal ash retention facilities, and requirements for reducing carbon dioxide emissions. Finally, owners of coal generating units would of course continue to incur additional capital expenditures to maintain aging coal-fired units.

Table 2: Estimated Environmental Upgrade Capital Expendatures (Million 2009$)

Plant Name	FGD Total Project Cost (Million $)	SCR Total Project Cost (Million $)	Baghouse Capital Cost (Million $)	ACI Capital Cost (Million $)	Wet Cooling Tower Capital Cost (Million $)	Total Capital Expenditures (Million $)
Asbury 1	$146		$36	$3		**$186**
Asbury 2	$26		$5			**$31**
Blue Valley 2	$34	$12	$8	$3		**$56**
Blue Valley 3	$67	$24	$17	$3		**$112**
Blue Valley ST1	$34	$12	$8	$3		**$56**
Chamois 1	$22	$7	$5		$10	**$44**
Chamois 2	$48	$16	$10	$3	$21	**$99**
Columbia 5	$26	$9				**$35**
Columbia 7	$32	$11				**$43**
Hawthorn 5				$4	$92	**$97**
Iatan 1	$343	$145	$93	$4	$113	**$697**
James River PS 1	$30	$10	$6			**$46**
James River PS 2	$30	$10	$6			**$46**
James River PS 3	$49		$11	$3		**$62**
James River PS 4	$61		$14	$3		**$78**
James River PS 5	$91	$33	$22	$3		**$149**
Labadie 1	$292	$120	$88	$4	$89	**$592**
Labadie 2	$292	$120	$88	$4	$89	**$592**
Labadie 3	$309	$128	$93	$4	$96	**$631**
Labadie 4	$309	$128	$93	$4	$96	**$631**
Lake Road 3	$24	$9	$6			**$40**
Lake Road 4	$100	$41	$28	$3	$32	**$205**
Marshall 5	$25	$9				**$34**
Meramec 1	$107	$38	$25	$3	$46	**$218**
Meramec 2	$107	$38	$25	$3	$46	**$218**
Meramec 3	$181	$69	$46	$3	$58	**$358**
Meramec 4	$212	$83	$55	$4	$68	**$421**
Missouri City 1	$38	$15	$12		$15	**$80**
Missouri City 2	$38	$15	$12		$15	**$80**
Montrose 1	$136	$50	$38	$3	$53	**$279**
Montrose 2	$136	$50	$38	$3	$53	**$279**
Montrose 3	$136	$50	$38	$3	$53	**$279**
New Madrid 1	$299		$79	$4	$93	**$475**
New Madrid 2	$299		$79	$4	$93	**$475**
Rush Island 1	$306	$126	$92	$4	$96	**$623**
Rush Island 2	$306	$126	$92	$4	$96	**$623**
Sibley 1	$56	$19	$12	$3	$26	**$115**
Sibley 2	$52	$17	$11	$3	$24	**$107**
Sibley 3	$238	$95	$62	$4	$74	**$474**
Sikeston PS 1		$62	$41	$3		**$106**
Sioux 1	$283	$116	$85	$4	$85	**$573**
Sioux 2	$283	$116	$85	$4	$85	**$573**
Southwest PS ST1		$49	$37	$3		**$89**
Thomas Hill 1	$127	$45	$30	$3	$50	**$255**
Thomas Hill 2	$176	$66	$44	$3	$57	**$346**
Thomas Hill 3	$324	$135	$87	$4	$104	**$655**

Table 3: Economic Merit of Existing Coal Fleet Relative to Alternative Supply and Demand Side Options ($/MWh)

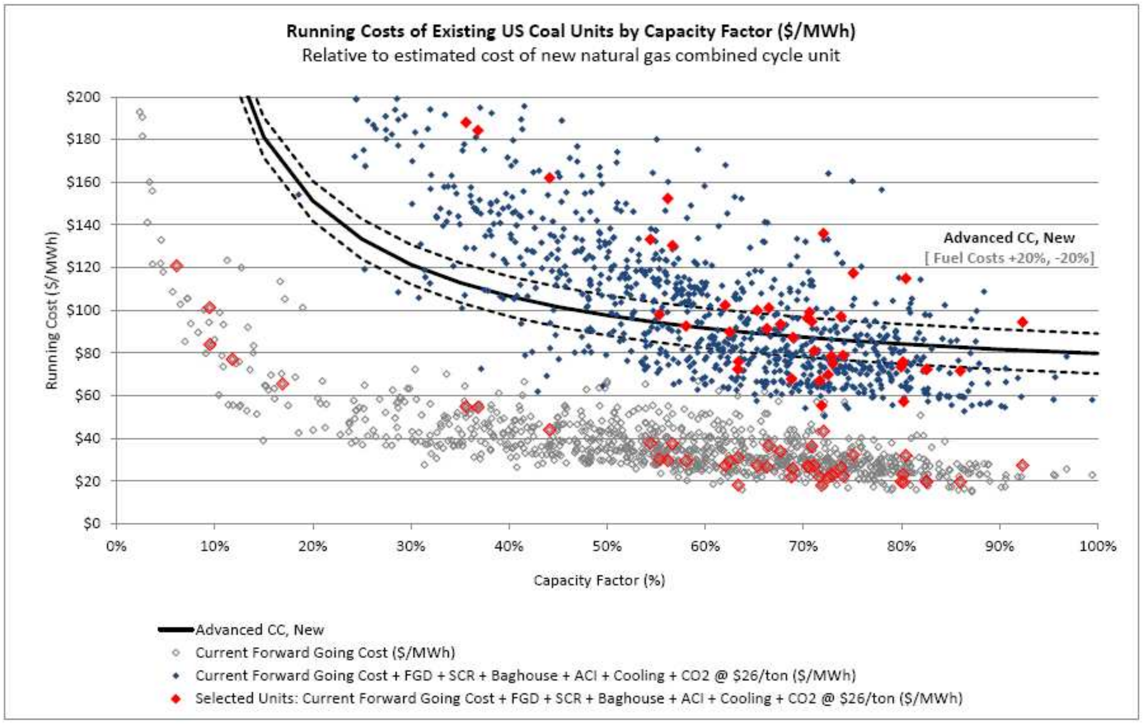
Plant Name	Nameplate Capacity (MW)	First Year of Operation	Capacity Factor, Average 2008-2009	Forward-Going Cost for Existing Coal Units* ($/MWh)	Estimated All-in Cost of a New Natural Gas CC** ($/MWh)	Estimated Cost of Existing Gas CC** ($/MWh)	Estimated Cost of Converting Station to Natural Gas** ($/MWh)	Cost of Energy Efficiency ($/MWh)
Asbury 1	213	1970	71.1%	**$81.0**	$84.0	$67.0	$80.1	$50.0
Asbury 2	19	1986	0.3%	++				
Blue Valley 2	25	1958	35.6%	**$188.0**	$88.1	$69.0	NA	$50.0
Blue Valley 3	65	1965	16.9%	**$241.9**	$117.1	$73.5	$101.7	$50.0
Blue Valley ST1	25	1958	36.8%	**$184.3**	$87.2	$68.9	NA	$50.0
Chamois 1	15	1953	56.2%	**$152.4**	$80.0	$67.5	NA	$50.0
Chamois 2	44	1960	92.3%	**$94.4**	$72.9	$66.5	NA	$50.0
Columbia 5	17	1957	11.8%	++				
Columbia 7	22	1965	9.5%	++				
Hawthorn 5	594	1969	71.9%	**$55.2**	$83.7	$67.0	$69.4	$50.0
Iatan 1	726	1980	63.4%	**$75.7**	$86.6	$67.2	$69.0	$50.0
James River Power Statior	22	1957	56.7%	**$130.2**	$78.3	$67.5	NA	$50.0
James River Power Statior	22	1957	54.4%	**$133.1**	$79.0	$67.6	NA	$50.0
James River Power Statior	44	1960	66.5%	**$101.1**	$75.9	$67.1	$82.1	$50.0
James River Power Statior	60	1964	70.8%	**$94.7**	$75.0	$67.0	$78.7	$50.0
James River Power Statior	105	1970	67.7%	**$93.3**	$75.6	$67.1	$78.3	$50.0
Labadie 1	574	1970	80.0%	**$73.4**	$81.5	$66.8	$70.6	$50.0
Labadie 2	574	1971	86.0%	**$71.5**	$80.1	$66.6	$70.0	$50.0
Labadie 3	621	1972	82.6%	**$72.1**	$80.9	$66.7	$70.0	$50.0
Labadie 4	621	1973	82.5%	**$72.1**	$80.9	$66.7	$70.0	$50.0
Lake Road 3	13	1962	0.1%	++				
Lake Road 4	90	1966	72.0%	**$135.9**	$83.7	$67.0	$75.7	$50.0
Marshall 5	17	1967	44.1%	**$162.1**	$83.0	$68.2	NA	$50.0
Meramec 1	138	1953	70.6%	**$98.9**	$84.1	$67.0	$75.1	$50.0
Meramec 2	138	1954	73.8%	**$96.9**	$83.1	$66.9	$74.2	$50.0
Meramec 3	289	1959	66.3%	**$91.3**	$85.6	$67.1	$74.1	$50.0
Meramec 4	359	1961	68.9%	**$87.2**	$84.6	$67.0	$75.1	$50.0
Missouri City 1	23	1954	9.5%	++				
Missouri City 2	23	1954	6.1%	++				
Montrose 1	188	1958	62.0%	**$102.3**	$87.2	$67.3	$76.1	$50.0
Montrose 2	188	1960	65.3%	**$99.8**	$85.9	$67.2	$75.4	$50.0
Montrose 3	188	1964	70.5%	**$96.4**	$84.2	$67.0	$74.6	$50.0
New Madrid 1	600	1972	68.8%	**$67.7**	$76.7	$67.1	$69.1	$50.0
New Madrid 2	600	1977	71.7%	**$67.0**	$76.1	$67.0	$68.9	$50.0
Rush Island 1	621	1976	80.2%	**$75.8**	$81.4	$66.8	$72.7	$50.0
Rush Island 2	621	1977	72.9%	**$78.3**	$83.4	$66.9	$73.5	$50.0
Sibley 1	55	1960	75.1%	**$117.3**	$82.8	$66.9	$78.8	$50.0
Sibley 2	50	1962	80.4%	**$114.8**	$81.4	$66.7	$78.3	$50.0
Sibley 3	419	1969	55.3%	**$97.8**	$90.3	$67.6	$73.8	$50.0
Sikeston Power Station 1	261	1981	80.2%	**$57.2**	$73.5	$66.7	$68.8	$50.0
Sioux 1	550	1967	58.0%	**$92.4**	$88.9	$67.4	$72.3	$50.0
Sioux 2	550	1968	62.5%	**$89.8**	$87.0	$67.3	$71.7	$50.0
Southwest Power Station	194	1976	63.3%	**$72.3**	$76.6	$67.2	$79.9	$50.0
Thomas Hill 1	180	1966	74.0%	**$78.8**	$75.6	$66.9	$70.4	$50.0
Thomas Hill 2	285	1969	73.0%	**$75.0**	$75.8	$66.9	$69.6	$50.0
Thomas Hill 3	670	1982	72.5%	**$69.7**	$75.9	$66.9	$67.0	$50.0

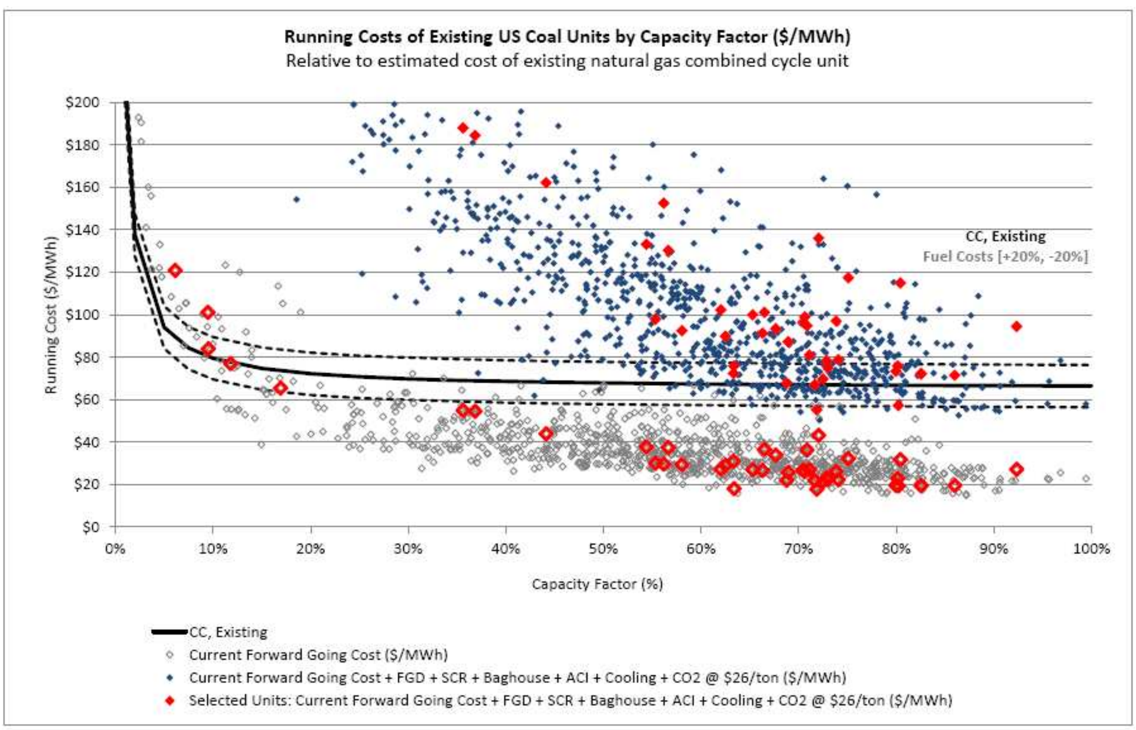
*Includes $26/tCO2 cost
**Includes $26/tCO2 cost; assumes that gas unit runs at same capacity factor as coal unit
***Assumed capacity factor of 40% & 10% CRF;
****Assumed cost of energy efficiency ++ $/MWh values not included for units with capacity factor <12%

The following figures indicate the economics on a $/MWh per capacity factor basis of all non-cogenerating coal units in the United States. Missouri units ("selected units") are demarcated by empty red markers while other coal units are demarcated with empty grey markers. Also indicated is the effect of environmental controls on each of the coal units according to projections developed by Sargent & Lundy for EPA's IPM Model v.4.10. Missouri units are demarcated by filled red markers while other coal units are demarcated with filled blue markers. The top figure indicates how the economics of these coal units compare with the running cost of a new combined cycle natural gas unit at varying capacity factors, while the bottom figure compares the coal units against the running cost of an existing combined cycle.[9]

Figures 1 and 2 – Running Costs of Coal Units Compared to New and Existing Natural Gas.

[9] This analysis uses natural gas as a comparison because of the adequacy of publicly-available data. However, consistent with our comments here, Sierra Club urges the Commission to require utilities to consider all available resources, including wind, solar, and demand-side management, which in many cases, will be less expensive and less polluting than natural gas.


Running Costs of Existing US Coal Units by Capacity Factor ($/MWh)
Relative to estimated cost of new natural gas combined cycle unit
Running Cost ($/MWh)
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Capacity Factor (%)
Advanced CC, New
[Fuel Costs +20%, -20%]
Advanced CC, New
Current Forward Going Cost ($/MWh)
Current Forward Going Cost + FGD + SCR + Baghouse + ACI + Cooling + CO2 @ $26/ton ($/MWh)
Selected Units: Current Forward Going Cost + FGD + SCR + Baghouse + ACI + Cooling + CO2 @ $26/ton ($/MWh)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40%
50%
60%
70%
80%
90%
100%
Capacity Factor (%)
CC, Existing
Fuel Costs [+20%, -20%]
CC, Existing
Current Forward Going Cost ($/MWh)
Current Forward Going Cost + FGD + SCR + Baghouse + ACI + Cooling + CO2 @ $26/ton ($/MWh)
Selected Units: Current Forward Going Cost + FGD + SCR + Baghouse + ACI + Cooling + CO2 @ $26/ton ($/MWh)

Our initial evaluation of publicly available data for the Missouri coal fleet shows when compliance with EPA regulations is evaluated 17.2% of coal capacity is vulnerable (deemed high risk or where retirement is most economic). As stated above, this triage data is conservative in that it does not include the cost of controlling coal combustion residuals, wastewater effluent or other costs that coal-fired plants could face to continue operation. These added compliance requirements are being considered by EPA and will likely be implemented over the next 5 years.

5. RELIABILITY

Reliability is a fundamental concern of the Commission, and rightfully so. As such, it warrants careful analysis. In fact, because parts of Missouri are within the Southwest Power Pool Regional Transmission Organization (SPP RTO), some regions within the Midwest Independent Transmission Service Operator (MISO), and some areas not a member of an RTO or ISO, it is appropriate for the Commission to consider no fewer than three separate studies. This is necessary to ensure that the generation, transmission, and other considerations are sufficient to ensure reliability within each of those regions, each with its own reserve margin target and contingency plans.

In their presentation to the Commission on October 26, 2011, Southwest Power Pool states that "SPP has found if the EPA's IPM modeling assumptions were to be deployed during 2012 Summer [sic] peak conditions, then FERC and NERC regulations would be violated."[10] This should give Commissioners pause and, if true, might require immediate and drastic reaction. However, as explained by Bruce Biewald, the SPP analysis is not an analysis of CSAPR and the possible impacts of CSAPR on the SPP system but rather it is a load flow modeling exercise in which SPP removed all generation units which consumed no fuel in the EPA models. Because those units are almost entirely gas-fueled or dual gas/oil-fueled units used to meet peak a small

[10] SPP Presentation to the Missouri Public Service Commission, "SPP Reliability Assessment Based on EPA CSAPR Model," October 26, 2011.

number of hours per year, there is no evidence that they would be retired in response to CSAPR and therefore the decision to remove them from the load flow analysis is unreasonable.[11]

A proper analysis of CSAPR would consider all options available to each generator within the area of study, in this case SPP. An objective analytical approach which considered how various realistic scenarios influenced system dispatch and reliability would be employed, and only then would the decision makers be in a position to truly understand the implications of CSAPR (or any other regulation of combination of regulations) on system reliability. To more accurately gauge system reliability, a study must also use all available information to predict which units will be offline temporarily during a retrofit and when, which units will be permanently retired and effective upon which date, and finally which units will be mothballed, available to return to service within a timeframe of weeks or months should the EPA enter into a consent decree. As a final backstop, the Department of Energy may use its emergency powers to keep essential generation on-line, or the President may use emergency powers to delay requirements in order to protect national security.[12] The study would gather the information available from the numerous integrated resource plans (IRPs), rate cases, and other dockets, from each state within the RTO or ISO. It would also incorporate information gleaned from 10-K and other financial statements. A proper analysis would also consider which tools the RTO or ISO has to incentivize or require sufficient generation capacity, such as reliability must-run, capacity payments, or other methods to retain generation or even return it from retirement or mothball status. An example of this kind of detailed analysis comes from the Ameren Missouri IRP, filed in early 2011. In it, Ameren details that Meramec, an 839 MW coal fired power plant which could reasonably be considered "at risk" of retirement could be retired without any additional supply side resources added without threatening reliability.[13] Ameren's IRP is clear: with "DSM cost recovery solutions"[14] made available through a Missouri Energy Efficiency Investment Act (MEEIA) filing for which it

[11] Biewald, Bruce, Declaration Regarding Southwest Power Pool Analysis of CSAPR Impacts, October 27, 2011. Available at www.synapse-energy.com

[12] Jennifer Macedonia et al, "Environmental Regulation and Electric System Reliability," Bipartisan Policy Center, June 2011.

[13] Ameren 2011 IRP, Chapter 10, Appendix B, page 8.

[14] Ameren 2011 IRP, Figure 10.6, Chapter 10, page 15.

will file in the first quarter 2012[15], Ameren could retire its at risk coal fired power plant and still comply with the IRP's requirement to "provide the public with energy services that are safe, reliable, and efficient."[16]

Compliance with CSAPR or any other regulation is, fundamentally, an exercise in planning. The regulations themselves, while refined during the public process, are finally enacted after many years of initial public notice, during which time individual utilities and entire RTOs and ISOs prepare for the possibility and then eventuality of the rules through IRPs and other planning processes. In the case of the EPA's Cross-State Air Pollution and Utility Air Toxics Rules "come after more than a decade of notice, and allow for more technology options and approaches than previously expected."[17]

Naturally, reliability concerns are not overlooked during these processes. Timely anticipation of upcoming EPA regulations is likely a reason why "many of the companies that own a substantial amount of the nation's coal-fired generating units have recently reported that they are well positioned to comply with the upcoming EPA regulations."[18] In addition to the planning process, a number of plant owners are in compliance with some or all of the upcoming EPA requirements due to more stringent state regulation or, in the case of American Electric Power, a 2007 consent decree.

While few if any specific planning exercises are flawless, the interconnected nature of the grid helps to ensure that an unexpected or unforeseen outcome in a specific utility or sub-region can be mitigated with the help of neighboring systems.

NERC analysis of upcoming EPA regulations indicates that planning reserve margins remain comfortable in the Southwest Power Pool, and that SPP does not appear to be one of the regions where resource adequacy deteriorates significantly due to EPA regulations

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[15] Surrebuttal Testimony of Matt Michaels, Case No. EO-02011-0271, page 33, lines 10-11.

[16] 4 CSR 240-22.010(2).

[17] Tierney, Susan F. "Testimony of Susan F. Tierney, Ph.D. Before the U.S. House of Representatives Committee on Energy and Commerce, Subcommittee on Energy and Power," September 14, 2011, page 5.

[18] Ibid, page 12.

(see e.g. Results for 2018, Figure 16).[19] However, utilities, and resource providers must be comprehensive in considering the potential impacts and responses to the regulations in order to ensure continued service at reasonable costs and impacts to ratepayers.

Because the resource mix, regulatory requirements, and market structures vary widely across RTOs and ISOs, it should not be surprising that the various regions have vastly different strategies for maintaining system reliability whilst complying with the new EPA regulations. In addition to MISO and SPP, ISOs and RTOs representing New York (NYISO), the Mid-Atlantic (PJM), and Texas (ERCOT) have submitted comments requesting that affected units be offered a "safe harbor" if they provide the Regional Transmission Organization with notice of their intended shutdown at least two years before the EPA compliance deadline, are identified as "Reliability Critical Units," and the mitigations are expected to take more than three years to be placed into service.[20] The "safety valve" as described by the RTOs and ISOs above "would apply on a case-by-case basis and the Joint TRO Commenters anticipate that it would not need to be invoked often, if at all."[21] ISO New England is fully prepared to ensure reliability and efficient market operation while utilities and other generation owners ensure compliance with EPA regulations. They do not anticipate needing a case-by-case safety valve or other extension due to a combination of transitioning to gas generation over the past decade or so, using "market signals" to direct the kind of generation needed to offset losses from coal- and oil- fired power plants retirements, and including the effects of EPA rules in its transmission planning process.[22][23]

RTOs and ISOs, and indeed utilities themselves have a broad variety of techniques to maintain reliability, and will likely incorporate a number of the following approaches to varying degree. Scheduling retrofits in a scheduled orderly manner to ensure sufficient capacity during months of expected peak demand is essential. New generation, be it natural gas fired or renewable or both

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[19] 2010 Special Reliability Scenarios Assessment: *Potential Resource Adequacy Impacts of U.S. Environmental Regulations*; NERC, October 26, 2010.

[20] Craig A. Glazer et al., "Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection L.L.C., and the Southwest Power Pool," EPA-HQ-OAR-2009-0234, EPA-HQ-OAR-2011-0044, and FRL-9286-1, DATE!?!?

[21] Ibid.

[22] "Grid Operator Dismisses Need For EPA Utility Rule Reliability 'Safety Valve'," InsideEPA.com, November 11, 2011.

[23] Chadalavada, Vamsi. "Discussion of the 2012 Work Plan DRAFT", ISO New England, December 12, 2011.

may be part of the solution, and various entities who are a necessary part of the process may speed or slow that process through permitting, bureaucracy, incentive payments, and other means. Utilities or state agencies can implement energy efficiency programs sufficient to defer new generation a few years or more. Capacity additions at individual plants, sometimes only a few megawatts per project, can help to ensure peak load capacity. New transmission to allow for PPAs or the reduction of load pockets can be used to reduce the probability of service outages. Ensuring that mothballed generators are ready to be deployed in as short a timeframe as can be reasonably expected provides more certainty. Expanding demand response programs is a cost effective strategy for the highest demand hours as well.

6. ALTERNATIVE COMPLIANCE MECHANISMS

Alternative compliance mechanisms, such as the repowering or strategic retirement of coal units, would avoid the large environmental-compliance investments, while resulting in much larger reductions in multiple pollutants. Replacing coal with a portfolio of natural gas, renewable energy, and efficiency can avoid many of the environmental regulatory costs currently enacted or in process. Alternative mitigation options, including fuel switching, purchasing existing combined-cycle capacity, building or buying new combined-cycle capacity, building or buying wind generation, and energy efficiency would eliminate potential costs from other upcoming federal requirements, as shown in Table 4.

Table 4: Contribution of various emissions mitigation options to compliance with various regulations

	Cross-State Air Pollution Rule (CSAPR)	Air Toxics Rule (MACT)	Regional Haze Rule (BART)	Ozone NAAQS	SO_2 NAAQS	Coal Combustion Residuals Rule	Cooling Intake Structures Rule	Effluent Limitation Guidelines	Carbon Dioxide Limitations
Flue Gas Desulfurization (FGD)	○	○	○		○				
Selective Catalytic Reduction (SCR)	○		○	○					
Baghouse & ACI		○	○						
Recirculating Cooling Tower							●		
Conversion to Natural Gas	○	●	○	○	●	●		●	○
Replacement with Natural Gas CC	○	●	○	○	●	●	●	●	○
Renewable Energy (Wind)	●	●	●	●	●	●	●	●	●
Energy Efficiency	●	●	●	●	●	●	●	●	●

● = Option offers full compliance with regulatory standard
○ = Option assists in mitigation, or provides element of compliance with regulatory standard

Upcoming regulations provide the opportunity and create the necessity for comprehensive and coordinated analysis and planning for decisions about existing generating units.

There are several relevant developments in the Southwest Power Pool (SPP). SPP currently only operates an energy imbalance service, but it is in the process of developing other energy markets. SPP began developing its Integrated Marketplace in 2009; it will include centralized dispatch, a process for committing reliability units, and a day-ahead market with transmission congestion rights.[24] SPP's actions in this and related areas will affect Missouri utilities and Missouri policy directions in interesting ways. For example, its consolidation of the balancing areas into one SPP

[24] Information available from SPP at http://www.spp.org/section.asp?pageID=138

balancing area is likely to improve the economics of wind (e.g. by allowing intra-SPP entities to buy the cheapest intra-SPP wind) and allow more of it to be integrated, as well as resulting in an increased value of the capacity credit given for wind. This could foster wind resources in the area, which could constitute an important contribution to the region's economy.

The Planning Authorities in the Eastern Interconnect have created the Eastern Interconnection Planning Collaborative (EIPC) to model the impact on the electric grid of various policy options of interest to states, provincial, and federal policy makers and other stakeholders. Preliminary results from the EIPC modeling effort indicate that, in scenarios that include a national carbon price, SPP could serve as an important and significant source of wind power for other regions, and that exports from SPP to other regions could be large. Additional scenarios, such as the national RPS (Renewable Portfolio Standard) future, are likely to also show big wind build-outs in the SPP region.

7. ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response are resources that could bring significant benefits to Missouri by ensuring a resilient power system in the face of upcoming regulations and other risk factors. Energy efficiency can reduce load growth, and reduce system peak demands thereby providing a long-term resource adequacy benefit, and demand response can serve as a short-term reliability resource – important benefits as utilities consider whether to retrofit or retire existing generating capacity. Energy efficiency and demand response also reduce costs to consumers. These benefits warrant consideration of energy efficiency on a level playing field with other resources in IRP, and both energy efficiency and demand response as important alternative resources in compliance decisions pertaining to units affected by EPA regulations.

Energy efficiency means providing the same or better level of service or production while reducing the energy consumption and costs to operate electric appliances, heating and cooling systems, or entire building envelopes. Energy efficiency programs and policies promote the techniques, measures and devices that provide equal or better service while using less energy than other measures. Consider the use of an efficient washing machine:

the clothes get just as clean as when using a less efficient appliance, but the washing machine uses less energy and costs less to run.[25]

Efficiency is often the lowest cost method of providing for consumer energy needs, and provides persistent reductions in consumer energy bills, emissions of greenhouse gasses and criteria pollutants, water use, and dependence on imported fuels. Efficiency programs provide significant local employment benefits in the sales and installation of lighting, insulation, and HVAC equipment; jobs which cannot be outsourced.

Energy Efficiency is Low-cost Resource

Throughout the United States, the cost of saving a kilowatt-hour (kWh) of electric energy has proven lower—far lower—than the cost of generating that same kWh. One comprehensive review of state and utility efficiency programs by ACEEE in 2009 concluded that the average program costs over multiple years and states ranged from 1.5 to 3.4 cents per kWh, with a median value of 2.7 cents/kWh and an average value of 2.5 cents/kWh.[26], [27] ACEEE notes that "recent conventional energy supply-side options have typically cost between $0.07 and $0.15 per kWh — about three to four times the cost of energy efficiency investments.[28] This comparison is presented in Figure 3, below which is taken from ACEEE's recent report.[29]

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[25] Energy efficiency can also mean achieving the same level of service through different means. Consider building design and industrial processes: building occupants require sufficient lighting, cooling, and heating to productively perform their duties in comfort. Reaching this level can be accomplished in several different ways, all with varying energy use. Buildings can have long rows of overhead lighting or they can have skylights to let in natural light. The latter requires less energy to accomplish the same goal and also increases worker productivity, as people work better with some natural daylight.

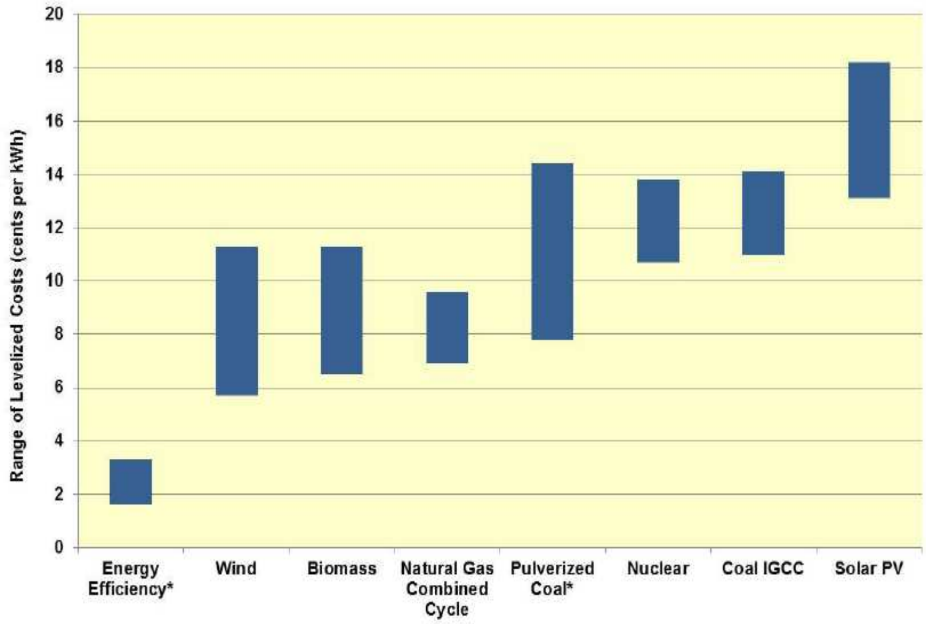
[26] ACEEE 2009. Savings Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs

[27] The utility cost of saved energy through energy efficiency programs represents the costs incurred by a utility or efficiency program administrator. The utility cost typically includes the costs associated with program administration, marketing, measurement and evaluation, and participant incentives and rebates, while it excludes participants' costs, which is the cost participants pay minus the amount of utility incentives.

[28] Ibid.

[29] R. Neal Elliott, Rachel Gold, and Sara Hayes, "Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency," ACEEE White Paper, August 2011.

Figure 3: Comparison of cost of various energy resources in the United States (cents per kWh)[30]



Another study, summarized below, compares a number of efficiency program cost estimates from states with very aggressive programs over several years found a similar trend.[31] The average is ¢2.6 per kWh (adjusted to $2010). It is also important to note that this study found economies of scale in the cost of efficiency programs. It found a trend for every observed utility or entity that the cost of the programs decreased as the scale of the program expanded.

Missouri has tremendous potential for developing EE and demand response

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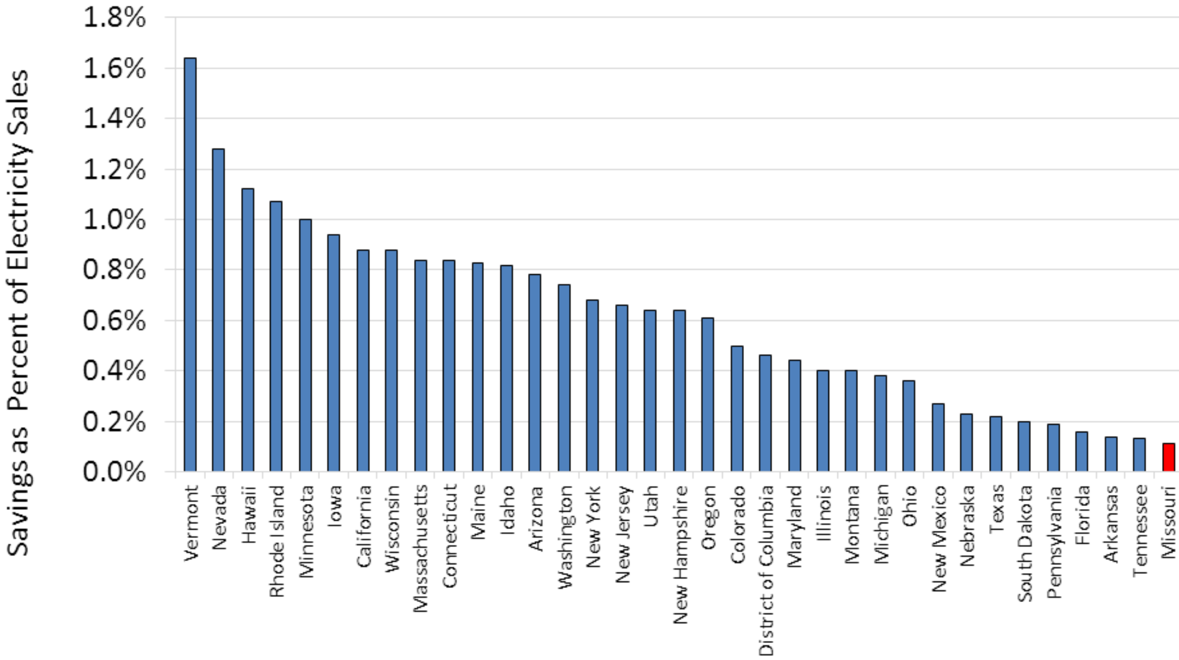
[30] R. Neal Elliott, Rachel Gold, and Sara Hayes, "Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency," ACEEE White Paper, August 2011.

[31] Synapse Energy Economics 2008.

Historical achievements through utility efficiency programs, codes and standards as well as potential studies have proven that significant amounts of energy efficiency potential are available almost everywhere households and businesses exist. Among many states, energy savings potential in Missouri appear particularly underutilized given that its

Figure 4. 2009 Incremental Electricity Savings by State: Top 35 States[32]



efficiency programs have not been active in the past. For example, the state energy efficiency score card reports by ACEEE in 2010 and 2011 ranked Missouri around 35th in terms of energy savings as % of sales. Figure 4 above shows the 2011 study result.

Energy efficiency is a long term resource that contributes to resource adequacy

Numerous states and utilities have actually incorporated energy efficiency in resource plans or in wholesale markets in the past, including states with both restructured and regulated wholesale power markets. A study by Lawrence Berkeley National Laboratory (LBNL) in 2008 investigated how and too what extent utility resource plans incorporate

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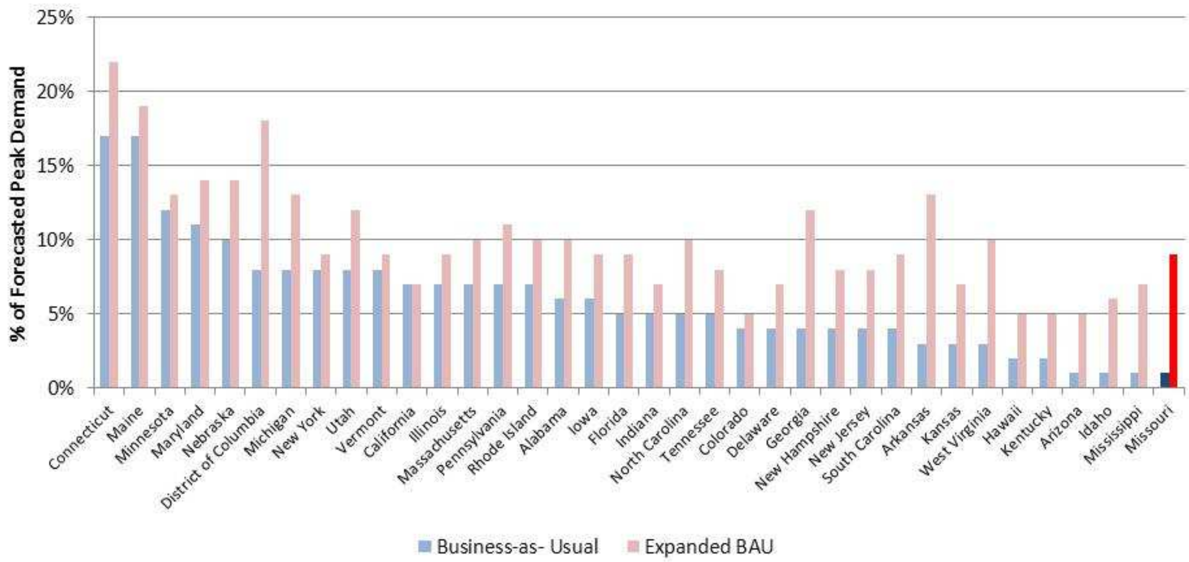
[3232] Created based on ACEEE 2011 State Energy Efficiency Scorecard energy efficiency in the West. The study found that many utilities incorporate energy efficiency in their integrated resource plans in the West and recognize its impact in the form of reduced energy and peak load growth rates. This impact among leading utilities in the west ranges from 40% to 70% reductions in those growth rates.[33]

Demand response is a short term reliability resource

In addition to energy efficiency resources, demand response resources are also helpful to reduce supply resource and grid constrains and to maintain or improve system reliability. As such, DR is an important tool for the state and region in addressing potential impacts of EPA regulations and utility compliance decisions. A recent study by Brattle Group, commissioned by the Federal Energy Regulatory Commission (FERC) identified large untapped demand response resources in various parts of the country even for the regions like New England that are known for their advanced demand response programs. The potential to increase demand response is particularly remarkable for Missouri, whose demand response is currently only about 1% of the peak load according to the study. However, the study found Missouri could increase its DR penetration to 9% by 2014 under the Expanded BAU scenario where the study assumes a state achieves best practices levels of participation, along with a modest amount of advanced metering infrastructure deployment.

[33] Nicole Hopper et al. *Energy Efficiency as a Preferred Resource: Evidence from Utility Resource Plans in the Western United States and Canada,* September 2008. Lawrence Berkeley National Laboratory

Figure 5. FERC 2009 National Demand Response Potential: Top 36 States for the Business as Usual Case with Missouri Highlighted[34]



Regions with a deregulated power market such as ISO New England and PJM have successfully incorporated energy efficiency and demand response in their forward capacity markets. For example, 822 MW of energy efficiency and 14,118 MW of demand response were cleared in the latest capacity auction (the 2014/2015 Base Residual Auction) in PJM, which represent 1% and 9% of the total capacity (about 150,000 MW) or 5% and 90% of the total new capacity (about 15,700 MW) respectively.[35]

[34] Created based on Brattle Group et al. *A National Assessment of Demand Response Potential*. Federal Energy Regulatory Commission June 2009.

[35] PJM, 2014/2015 RPM Base Residual Auction Result, Table 5 and Table 6B, http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx

DR can reduce resource constraints

DR can be used very effectively to address specific constraints on the transmissions system. Following are some examples of locations where demand response has been used to address constraints:

> **Texas**: "A widespread power disruption loomed over the Texas power grid on Thursday, August 4, as temperatures soared well into the triple digits and the state's available electric resources were nearing exhaustion from the high demand….But the disruption was avoided with the help of a small demand response program that added as much as much as 1,400 megawatts to the surplus, curtailing the problem by the afternoon"[36]

> **New England**: "The heat wave that enveloped the Northeast [in July 2011] and brought with it exceedingly hot temperatures and high levels of humidity caused electricity demand in the six New England states to soar… Various demand response program participants helped ease demand by more than 600 megawatts during peak electricity usage periods, according to grid operators."[37]

Demand side resources can be integrated into competitive markets

In order to maximize the reliability benefits of DR, integration of demand response into markets is one area that could be developed in the SPP region, to the benefit of Missouri ratepayers. Energy market designs and reliability planning processes affect the integration of demand-side management ("DSM"), including demand response ("DR") and energy efficiency ("EE") resources, into electricity systems. Modifying Regional Transmission Organization ("RTO") market rules, procedures, and planning processes can make existing electricity systems and markets more accessible to DSM.

Many of the RTOs, including ISO-NE, MISO, NYISO, and PJM, allow DR to participate in their capacity markets.[38] DR participation in these markets has generally increased in recent years. For example, PJM's most recent forward capacity market auction, for the

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[36] http://www.nappartners.com/news/large-heat-related-power-outage-avoided-in-texas

[37] http://www.nappartners.com/news/demand-response-programs-helped-new-england-iso-meet-electricity-demand

[38] ISO/RTO Council 2010. North American Wholesale Electricity Demand Response 2010 Comparison. Available at http://www.isorto.org/site/apps/nlnet/content2.aspx?c=jhKQIZPBImE&b=2708737&ct=8400541.

period June 2014 to May 2015, procured over 14,000 MW of demand response capacity resources.[39] Roughly 9% of the resources clearing the 2014/2015 PJM capacity auction were DR resources. The amount of DR that cleared the 2014/2015 base auction was over 50% greater than the amount of DR that cleared the 2013/2014 auction.[40] As another example, in ISO-NE's Forward Capacity Auction for the 2014/2015 commitment period, real-time demand response resources filled 4% of the auction's net installed capacity requirement of 33,200 MW.[41]

Allowing DR to participate in energy and ancillary services markets has been proposed or successfully implemented in New England, New York, PJM, the Midwest, and California.[42] However, DR is not well-integrated into the Day-Ahead and Real-Time energy markets or the ancillary services markets anywhere. In March of 2011, FERC issued an order on Demand Response Compensation in Organized Wholesale Energy Markets.[43] Order 745 provides that all RTOs that allow DR resources to participate in energy markets must pay those resources full Locational Marginal Prices at all hours. Order 745 will affect market dynamics and could affect the operations of existing or new resources when the demand response resource is more fully developed. The effect could be significant, and a positive one for ratepayers by reducing the operation of expensive marginal resources and reducing prices, as indicated by experience in PJM. According to PJM, demand response mitigated regional clearing prices 10 to 20 percent,

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[39] "Demand Resources and Energy Efficiency Continue to Grow in PJM's RPM Auction"; Press Release, PJM Interconnection, May 13, 2011.

[40] PJM 2011. 2014/2015 RPM Base Residual Auction Results. Available at http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx.

[41] Gottstein, Meg; *Examples for Dispatchable Demand Response Clearing the ISO-New England and PJM Forward Capacity Markets;* The Regulatory Assistance Project; August 9, 2011.

[42] ISO/RTO Council 2010. North American Wholesale Electricity Demand Response 2010 Comparison. Available at http://www.isorto.org/site/apps/nlnet/content2.aspx?c=jhKQIZPBImE&b=2708737&ct=8400541.

[43] FERC; "Demand Response Compensation in Organized Wholesale Energy Markets", Docket No. RM10-17-000; Order No. 745; March 15, 2011. Available at http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

and contributed 30 percent to the price reductions in the supply-constrained region within PJM.[44]

Market elements that support DSM

There are a number of market modifications that help encourage development of EE and DR resources, and some of them have been accomplished already in electricity markets in the U.S. These sorts of elements should be considered for inclusion in markets as they develop in the SPP region in order to benefit Missouri ratepayers. EE is able to participate in capacity markets to meet future reliability requirements in New England and PJM, which both hold capacity auctions several years in advance of need.[45] Allowing EE into the capacity markets and DR into the capacity, energy, and ancillary services markets is one important step,[46] but as noted previously, DR is not well-integrated into the Day-Ahead and Real-Time energy markets or the ancillary services markets anywhere (though PJM does allow DR to participate in one of its reserve markets). FERC Order 745 on demand response compensation in wholesale markets should help increase participation in the energy markets for DR.

8. COMPLIANCE DECISIONS AND JOB IMPACTS

Utilities' decisions on how to manage their plant fleet in the face of the EPA regulations while meeting their obligation to serve Missouri customers will have implications for jobs in Missouri. Evaluation of employment issues associated with compliance decisions should include a comprehensive consideration of potential job loss as well as job creation associated with investments in alternatives to aging coal capacity. Estimates of job impacts of environmental regulations often focus on job losses at power plants slated for

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[44] Dosunmu, Ade; "Up In Smoke"; Public Utility Fortnightly's Spark (on-line e-zine), June 29, 2011. Accessed July 1, 2011.

[45] Gottstein, Meg and Lisa Schwartz. The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects. May 2010. Available at http://www.raponline.org/document/download/id/91.

[46] Gottstein, Meg; *Examples for Dispatchable Demand Response Clearing the ISO-New England and PJM Forward Capacity Markets;* The Regulatory Assistance Project; August 9, 2011.

retirement and in supporting industry such as coal mines. These predictions paint a dire picture of the economy and the EPA as a "jobs killer."[47] In fact, these regulations can create jobs at affected plants by increasing demand for upgrade technology including installations of emissions controls required for compliance. They also increase pressure on displacement of fossil fuel generation with renewable energy and energy efficiency which both require new production and installation. All of these effects stimulate the economy, requiring supporting jobs for construction and operations of new technologies and, in the case of energy efficiency, saving consumers and businesses dollars that they can then invest or spend in their local economy.

Investments in energy efficiency and renewable energy have been shown to create more jobs per unit of energy when compared to traditional fossil fuel generation such as natural gas and coal. According to a 2010 comprehensive survey of job impacts by resource type in the United States,[48] the natural gas and coal industries create between 0.09 and 0.11 jobs in operations and maintenance per MW while wind jobs range between 0.14 and 0.40 for operations and maintenance and between 2.5 and 10 jobs in construction per MW. The solar industry typically creates more jobs per MW than wind, primarily because it consists of smaller projects that require more contracts to achieve the same amount of energy—the lowest figure citied for solar in this study was 7.14 jobs per MW. Another study focused on solar benefits in New Jersey[49] cited job impacts as high as 35 jobs per MW compared to 3 jobs per MW for natural gas and 7 jobs per MW for wind.

Energy efficiency and renewable energy also produce many more local jobs than do investments in fossil fuel burning resources. There are several reasons for this advantage:

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[47] See for example: "The EPA's giant green jobs killer," New York Post, August 21, 2011.

[48] Wei, Max, Shana Patadia, and Daniel Kammen, "Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the US?" Energy Policy 38 (2010), 919-931.

[49] Peter, Niklas, "Promoting Solar Jobs: A Policy Framework for Creating Solar Jobs in New Jersey," January 5, 2010.

- Energy efficiency is the cheapest resource available at an average of 2.5 cents per kWh[50] and some forms of renewable technology are projected to be competitive or less expensive in the long-term than natural gas generation.[51] This long-term cost savings accrues for ratepayers in the region.
- As households and businesses save on energy costs through efficiency measures, individuals can spend additional money in the local economy and businesses can re-invest their savings, both of which spur job growth.
- Clean energy investments require production, installation, and operation of new equipment (such as new boilers, wind turbines, and solar panels) generating both short and long-term employment. The impacts of these investments are more likely to be felt in-state than spending on fossil fuel generation.
- Renewable and energy efficiency projects also tend to be more labor-intensive than traditional generation, creating more jobs per dollar and per unit of energy.

The installation of emissions controls needed to comply with EPA rules will generate jobs in Missouri, as it will at many other plants throughout the U.S.[52] Continued operation of coal plants and supporting mines relies on existing capital equipment (so few if any new manufacturing and construction jobs result aside from routine capital maintenance), while installation and operation of the required control equipment will create entirely new economic activity. A Ceres and PERI report estimated the economic impacts of 36 states' compliance with the proposed CSAPR and MACT rules.[53] The authors concluded that pollution control investments would support nearly 684,000 direct

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[50] R. Neal Elliott, Rachel Gold, and Sara Hayes, "Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency," ACEEE White Paper, August 2011.

[51] Synapse Energy Economics, "Towards a Sustainable Future for the US Power Sector: Beyond Business as Usual, prepared for Civil Society Institute," November 16, 2011.

[52] There is evidence of job creation from actual experience at other plants that have upgraded their scrubbers. The Ceres-PERI report mentions that Westar, which operates Jeffrey Energy Center in Kansas, spent $500 million in upgrading the plant, requiring 850 construction workers (i.e., direct jobs) on-site at the peak of installation. PSEG, which operates Mercer and Hudson plants in New Jersey, spent $1.3 billion in upgrades, requiring 1600 workers at the peak of their activity. Luminant recently invested $100 million on a selective catalytic reduction (SCR) installation at its Sandow plant, employing 1200 construction workers at the peak of construction. See for example: "1,200 on the job at Sandow 4," Rockdale Reporter, February 4, 2010.

[53] "New Jobs—Cleaner Air: Employment Effects Under Planned Changes to the EPA's Air Pollution Rules," Ceres and Political Economy Research Institute, February 2011.

and indirect job-years[54] across the 36 states, i.e. 136,800 jobs for five years. In addition, nearly 775,000 direct and indirect job-years, i.e. 155,000 jobs for five years, would be created due to installation of new generation capacity to displace coal.

The report distinguished between impacts from installation of pollution controls and replacement capacity (e.g., new renewable investments) but also accounted for jobs lost due to coal retirements. While the installation of these controls is a short-term stimulus to the economy, there are long-term operations and maintenance (O&M) jobs that would also be created with the new emissions controls and new capacity. The net effect (jobs gained minus jobs lost) is estimated to be over 4200 long-term jobs in the US.

In this study, Missouri is estimated to spend $6.6 billion in pollution controls and $6.8 billion in new capacity. This stimulus to the state economy represents 60,000 job-years in construction of pollution controls and new capacity, 1,700 long-term jobs in operations and maintenance of these facilities, and 271 jobs lost to coal plant retirements. This means a short-term boost for Missouri's economy as these controls are installed and sustainability in the long-term as 1,500 net jobs would be created. Unfortunately, this balanced view is often ignored when discussing the implications of environmental regulations.

9. CONCLUSION

There are numerous upcoming regulations and requirements, particularly from the Environmental Protection Agency, that will affect the economics of existing power plants and thus affect the state and customers. The laws requiring these regulations have been on the books for decades, and in most cases, coal-fired power plant operators have been planning for compliance for just as long.

To avoid the potentially imprudent and unnecessarily high costs of a "rush to retrofit" approach to existing and pending public health and environmental regulation, the

[54] Direct jobs refer to workers on-site while indirect jobs are associated with suppliers of the installation activities (e.g. concrete). It should be noted that the total job estimates from this study only include direct and indirect jobs and exclude induced jobs, which result from workers re-spending their wages.

Commission should consider the tools and policies raised in these comments when facing requests by Missouri utilities for approval of their compliance plans. Given the number and coverage of EPA regulations, it is essential that the Commission and the utilities consider the impact of these regulations in a cohesive way rather than on a rule-by-rule basis. In sum, and as provided above, Sierra Club & Synapse recommends that:

- The Commission be cautious when a regulated utility requests approval to "rush to retrofit," whether through an IRP or a rate case. The commission should think beyond a simple selection among alternative power plant retrofits to determine the optimal configuration for meeting regulatory requirements over the long term.
- Utilities 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.
- The Commission establish a comprehensive and consistent process for considering utility proposals for major investments in existing generating units. 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.
- In general, for any investment decisions pertaining to EPA regulatory compliance the Commission should 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,

  (2) an objective analysis of how those uncertainties and risks affect 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.

  The Commission should issue rules or guidance that clearly articulate the criteria and required documentation for the analysis described above.

- 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 more tests.
- All resources should be considered on a level playing field, and decision-making should result in an integrated portfolio of resources with the mix of resources that will provide adequate and reliable service at the lowest life cycle cost.
- In its review of utility proposals 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 power plants in light of a rapidly changing landscape that disfavors coal, and that compare those costs to the variety of alternatives available to Missouri utilities. Underlying these considerations are the principles of prudency that apply to ratemaking, including the obligation for ongoing reassessment of avoidable costs.
- The Commission consider in the current period of rapid and important in environmental regulation, an "Integrated Environmental-Compliance Planning" (IECP) approach that would permit a state-wide evaluation of EPA regulations and the State's fleet of existing coal plants.
- The Commission require utilities to provide the anticipated costs and the potential risks of existing and emerging regulations for the whole range of pollutants in utility evaluations of their investment proposals.

- Replacing coal with a portfolio renewable energy, efficiency, and possibly natural gas can avoid many of the environmental regulatory compliance costs associated with regulations currently enacted or in process and should be part of the Commission's consideration of alternatives.
- The benefits of energy efficiency and demand response warrant consideration these resources on a level playing field with other resources in IRP, and both energy efficiency and demand response as important alternative resources in compliance decisions pertaining to units affected by EPA regulations.
- Evaluation of employment issues associated with compliance decisions should include a comprehensive consideration of potential job loss as well as job creation associated with investments in alternatives to aging coal capacity.

Thank you for the opportunity to submit these comments.