BEFORE THE OKLAHOMA CORPORATION COMMISSION

IN RE: INQUIRY OF THE OKLAHOMA CORPORATION) COMMISSION TO EXAMINE CURRENT AND PENDING) FEDERAL REGULATIONS AND LEGISLATION) IMPACTING REGULATED UTILITIES IN THE STATE OF) OKLAHOMA AND THE POTENTIAL IMPACT OF SUCH) REGULATIONS ON NATURAL GAS COMMODITY) MARKETS AND AVAILABILITY IN OKLAHOMA)	Cause No. PUD 201100077

Response to Issues and Questions

On Behalf of
Sierra Club

On the Topic of
Fuel-Source-Related Issues

July 18, 2011

1. INTRODUCTION

These comments are prepared for the Sierra Club by Paul Chernick and Rachel Brailove of Resource Insight, Inc., John Plunkett of Green Energy Economics Group, and Lucy Johnston of Synapse Energy Economics.

While the questions that the NOI identifies for Technical Session #2 are framed as being related to fuel sources, the questions reach beyond fuel issues, to the nature of integrated resource planning in response to environmental mandates. These comments therefore cover both strictly fuel-related issues and issues related to integrating supply and demand planning to respond to the high cost of continued operation of the coal plants facing requirements to install scrubbers under the Haze Rule and additional expensive controls under the Cross-State Air Pollution Rule, the Hazardous Air Pollutant rule, the Clean Water Act, and additional regulations.

2. RESPONSES TO QUESTIONS

Question 1. Are there alternative planning processes other than a regulated utility's Integrated Resource Plan (IRP) as described in OAC 165:35-37 that could be considered in determining the most effective strategy to include a holistic approach to Oklahoma's generation fleet and an analysis of the overall cost impact or benefits to ratepayers as it relates to federal mandates, fuel switching (converting from one fossil fuel to another type of fossil fuel), renewable portfolio standards, fuel diversity, system efficiency improvements, transmission expansions and other upcoming issues? If so, what kind?

In the current period of rapid and important in environmental regulation, the Commission should consider an “Integrated Environmental-Compliance Planning” (IECP) approach. 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. Oklahoma’s IRP process prescribed by OAC 165:35-37 provides for many important aspects of a “holistic approach to Oklahoma's generation fleet and an analysis of the overall cost impact or benefits to ratepayers" that should be the core of IECP, but it is also missing some very critical components. The strengths of the IRP include the following:

- The integrated consideration of "supply, demand-side and transmission options" (165:35-37-4(c)(5)).[1]
- The focus on the "action plan identifying …near-term…actions…" (165:35-37-4(c)(7)).
- Provision of the "data, assumptions and descriptions of models" supporting the utility analysis" (165:35-37-4(c)(9)). Unfortunately, the utility IRPs do not always thoroughly comply with this IRP requirement. In the case of the OG&E 2011 IRP, this documentation is limited to two pages and provides a very small portion of the data, assumptions and model input and output on which the IRP results are based. Most of the assumptions are redacted. In order to have meaningful review of the utility analyses and recommendations, the Commission should require early and detailed disclosure of data, subject to confidentiality agreement if necessary.

Despite these strengths, the IRP rules have 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. The Commission has explicitly raised some of these factors in this proceeding.
- 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 (including Schedule L under the Commission's IRP rules) are oriented around the utility's development and explanation of its preferred plan. In order to make informed choices on the pending important and

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[1] As described in greater detail in response to Question 10, it is more productive to approach detailed planning of demand-side resources through a statewide collaboration of the utilities and other interested parties, rather than primarily through the IRP process.

expensive decisions, 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 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. The IRP rules require that Schedule K of the IRP present "an assessment of the need for additional resources to meet reliability, cost and price, environmental or other criteria." In the current situation, the plan ought to also assess whether operation of particular existing resources (such as the coal plants affected by the Federal Implementation Plan (FIP) for regional haze) effectively meets "reliability, cost, environmental or other criteria," compared to alternatives.[2] 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.

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[2] While the 2011 OG&E IRP does examine the installation of scrubbers at Muskogee and Sooner, there are other problems with the OG&E IRP, such as its failure to reflect pending environmental requirements other than the Haze Rule FIP and its limited reviewability. Integrated compliance planning must consider the entire suite of forthcoming requirements, and not only those that are finalized.

- 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 in Sierra Club's response to Question A1 and in the first technical conference in this NOI, 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,[3] 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 sheer number and wide coverage of these pending rules mandates that the Commission and the utilities consider their potential impact in a comprehensive, rather than case-by-case basis, for both planning and cost recovery. The Commission should expect to see 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.

  A step-wise, consistent decision-making process for deciding whether to invest in retrofit of existing plants, new plants or other available resources is essential to ensuring the best outcome for ratepayers. Without such an

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

analysis, it is impossible for the Commission to fully assess whether maintaining, upgrading, and operating the existing fleet of plants is prudent, efficient, and a suitable long-term commitment of revenues to be raised from ratepayers.

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."[4] 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 NOx emissions, but the PUC also considered the effects of the alternatives on emissions of SO_2, particulates, mercury and carbon.[5]

In the near term, an IECP should probably be conducted 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. These would include the six coal units for which the FIP for regional haze proposed scrubbers:

- Muskogee 4,
- Muskogee 5,

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

5 "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)

- Sooner 1,
- Sooner 2,
- Northeastern 3, and
- Northeastern 4.

These units will also be under pressure to reduce summer NOx emissions by 50% to 60% as soon as feasible under the Cross-State Air Pollution Rule. The allocations of seasonal NOx allowances proposed by the EPA would only cover 40% to 50% of the units' historical NOx emissions; achieving those dramatic emissions would require selective catalytic reduction (SCR). As shown in Table 3 of Sierra Club's July 11, 2011 NOI responses, the six FIP-affected units face retrofit costs on the order of $1,000/kW to comply with pending requirements, in addition to increased operating costs.

The discussion in the July 13 Technical Session in this investigation highlighted the Commission's need for information to evaluate the merits of requests for pre-approval of environmental compliance costs. While some environmental compliance costs are unavoidable, 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.

Question 2. What is the estimated natural gas commodity supply, demand and price outlook in Oklahoma for the next ten and twenty years? Are there alternatives to natural gas as a fuel for electricity generation? How does the current and forecasted cost of natural gas compare to the current and forecasted cost of other alternative fuel sources (coal, wind, solar, hydro, nuclear and biomass) for electric generation?

The Sierra Club has limited comments on gas supply, demand and price outlook. For comments on generation alternatives, see the response to Question 3. The development of detailed cost comparisons for resources should probably be deferred to the proceeding on integrated environmental compliance planning that Sierra Club hopes the Commission will initiate promptly, based on this NOI.

As shown in Table 1, Oklahoma is a net exporter of natural gas, producing about three times as much gas as it consumes for all purposes: heating, other domestic and commercial uses, industry, and power production. In recent years, Oklahoma has produced less than 10% of its proved reserves in each year; rather than declining as gas is produced, proved reserves have actually been increasing.

Table 1: Oklahoma Natural Gas Statistics (Bcf)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Reserves	13,699	13,558	14,886	15,401	16,238	17,123	17,464	19,031	20,845	22,769
Production	1,613	1,615	1,582	1,558	1,656	1,639	1,689	1,784	1,887	1,858
Consumption	539	491	508	540	539	583	624	658	688	657
Net Exports	1,074	1,124	1,073	1,018	1,117	1,057	1,065	1,125	1,199	1,201

Notes: All data from EIA (www.eia.gov/state/state-energy-profiles-data.cfm?sid=OK)
Dry Natural Gas Proved Reserves
Natural Gas Marketed Production
Natural Gas Total Consumption
Net Exports = Production – Consumption

Replacing the entire output of the six units affected by EPA's Regional Haze FIP from gas combined-cycle energy would require about 170 Bcf annually, only about 15% of the average net increase in reserves since 2001.[6] The coal-plant energy replaced by wind, solar and efficiency will require no additional gas. The historical data certainly suggests that the supply of gas will exceed demand for the next ten and twenty years, even if the six coal units are entirely replaced with gas generation.

[6] This computation assumes an average heat rate of 7,500 Btu/kWh, roughly the efficiency of new gas combined-cycle plants. For the existing combined-cycle plants that are operating at inefficiently low levels, the heat rate and fuel requirements for incremental output would be lower than 7,500 Btu/kWh. Replacement energy from steam and combustion-turbine plant would require more than 7,500 Btu/kWh.

Question 3. What is the estimated intra and inter-state coal supply, demand and price outlook, including transport related issues, in Oklahoma for the next ten and twenty years? Are there alternatives to coal as a fuel for electricity generation? How does the current and forecasted cost of coal compare to the current and forecasted cost of other alternative fuel sources (natural gas, wind, solar, hydro, nuclear and biomass) for electric generation?

Sierra Club has no comments on coal supply, demand and price outlook, other than to note that the Powder River Basin coal used at Oklahoma coal plants (and specifically at the plants affected by the FIP) is subject to increasing demand, domestic and international. Rising demand is likely to increase the price of coal, improving the relative economics of alternative resources, including natural gas, renewables and energy efficiency.

The price of coal is only one factor in economic comparisons between the existing coal plants and alternatives. The costs of environmental compliance may well be more important than the cost of coal.

As for alternatives to coal as a fuel for electricity generation, the major near-term generation alternatives for Oklahoma are

- natural gas burned in existing steam plants,
- natural gas burned in existing combined-cycle power plants and combustion turbines,
- market purchases of energy,
- new natural-gas-fired combined-cycle and combustion-turbine power plants, and
- wind generation.

While not a generation resource, energy efficiency is also an important fuel-displacing resource for Oklahoma. For more discussion of the potential for energy-efficiency to reduce the cost of complying with the pending environmental requirements, see the response to Question 10.

In the longer term, solar, in-stream hydro, and sustainable biomass generation may also become important.

The following three sections provide additional information regarding various existing gas-fired resources available as part of an environmental compliance plan. In reviewing the potential identified below, it is useful to compare potential energy resources to the 19,000 GWh produced by the six FIP-affected units in 2009.[7] For additional information on renewable energy resources, see the response to Question 5. For additional information on energy efficiency potential and costs, see the response to Question 10.

Existing Oklahoma Gas Resources as Alternatives to Coal

Both OG&E and PSO/AEP, as well as other Oklahoma utilities and merchant generators, own gas resources that are significantly underutilized.

OG&E owns 2,665 MW of gas-fired steam plants, which operated at an average capacity factor of only about 19% in 2009;[8] 91 MW of modern, high-efficiency combustion turbines, which have operated at capacity factors of 2–5% in recent years;[9] and 1,165 MW of combined-cycle gas, which operated at an average capacity factor of 52%.[10]

PSO owns 2,192 MW of gas-fired steam plants, which operated at an average capacity factor of only about 19% in 2009; about 310 MW of modern, high-efficiency combustion turbines; and 689 MW of combined-cycle gas, which operated at an average capacity factor of 52%. In addition, its sister American Electric Power ("AEP") operating company Southwest Electric Power Company ("SWEPCo"), owns 1,818 MW of gas-fired steam plants in SPP, which operated

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[7] Most Oklahoma utilities, and SPP as a whole, have ample excess capacity, which is likely to increase with the development of renewable energy, so replacing the capacity of any retired coal units is likely to be less challenging than replacing the energy. In addition, the market cost of pure peaking capacity tends to be much lower than the cost of energy.

[8] This total includes about 170 MW of capacity at Muskogee 3, which OGE does not list in its 2010 IRP.

[9] These combustion turbines are about as efficient as the gas steam plants.

[10] All capacity ratings in these comments are summer capacities from the Energy Information Administration EIA-860 database. Capacity factors are computed from the energy data provided in the EIA-923 database.

at an average capacity factor of about 30% in 2009, as well as about 290 MW of modern combustion turbines, which operated at a 1% capacity factor.

Other Oklahoma generation includes about 4,700 MW of combined-cycle capacity, 400 MW of gas-fired steam, and 100 MW of modern CTs, operating at capacity factors similar to those of the OG&E and PSO plants.

These plants are all able to produce much more energy than they have in recent years. The gas steam plants—most of which were originally designed as baseload units—could easily operate at capacity factors of 60%, if they were needed and economic to replace retired coal plants. The same is true for the modern combustion turbines: many cogeneration systems and combined-cycle plants use similar combustion turbines in baseload operation. The more-efficient gas combined-cycle units, all of which are modern and designed to run as baseload service (generally with great flexibility), should be able to operate at capacity factors exceeding 85%. All of these gas-plant capacity factors are limited primarily by the lower load in off-peak hours, rather than any physical limits of the plants.[11]

As shown in Table 2 below, bringing these units to reasonably full output (60% capacity factors for steam plants and modern combustion turbines and 85% for gas combined-cycle) would produce 60,000 GWh annually, more than three times the annual generation by the six FIP-affected units of about 19,000 GWh.

[11] Load is met first by the plants with the lowest running costs (usually renewables, nuclear and then coal) with priority given to plants (especially nuclear and large coal units) that cannot readily vary output to follow load.

Table 2: Under-Utilized Capacity Owned by Oklahoma Utilities and Affiliates

Owner	Plant Type	Summer MW	2009 CF	Additional Available GWh
OG&E	Combined-Cycle	1,165	52%	3,368
OG&E	Gas Steam	2,665	19%	9,572
OG&E	Modern CT	91	5%	438
PSO	Combined-Cycle	689	52%	1,992
PSO	Gas Steam	2,192	19%	12,673
PSO	Modern CT	310	2%	2,254
Other OK	Combined-Cycle	4,671	44%	16,870
Other OK	Gas Steam	358	15%	1,406
Other OK	Modern CT	134	6%	631
SWEPCo	Gas Steam	1,818	30%	8,759
SWEPCo	Modern CT	294	1%	2,163
Total				60,126

While the dispatch of these units would be determined by regional supply and demand conditions, these values indicate the general magnitude of under-utilized gas capacity.

The cost of increasing output from these plants would be limited to the cost of additional fuel and a small amount of variable O&M.

Other Existing Generation In and Around Oklahoma as Alternatives to Coal

In addition to the generation owned by OG&E and PSO/AEP, a large amount of combined-cycle and steam natural-gas capacity is underutilized in Oklahoma and surrounding areas. The relevant region for this analysis includes at least SPP (which covers Oklahoma, Kansas, most of Nebraska, portions of Texas, Arkansas, Missouri, Louisiana, and New Mexico). The transmission system in the remainder of Arkansas, Louisiana, western Mississippi, and much of Missouri is operated by SPP; there is a substantial amount of under-utilized generation in these areas that may also be available to Oklahoma utilities.[12]

[12] The non-SPP portions of Texas and New Mexico are parts of the Texas (ERCOT) and Western (WSCC) interconnections, and are not well connected to SPP.

Even limiting the analysis just to SPP, there are about 5,300 MW of gas combined-cycle that operated at an average capacity factor of 23%, 7,000 MW of gas steam that operated at an average capacity factor of 17% in 2009, and at least 4,400 MW of modern combustion turbines operating at an average capacity factor of less than 5%.[13] This additional potential generation from underutilized plants totals about 74,000 GWh, nearly four times the energy output of the FIP-affected units.

Table 3: Other Under-utilized Capacity in SPP

Plant Type	Summer MW	2009 CF	Additional GWh
Combined-Cycle	5,309	30%	25,579
Gas Steam	7,048	17%	26,548
Modern CT	4,436	3%	22,150
Total			74,277

The Potential for Purchase of Existing Combined-Cycle Plants as Alternatives to Coal

In addition to increasing use of their own gas-fired generation and purchasing power in the short-term and spot energy markets, the Oklahoma utilities have the option of purchasing some of the approximately 6,900 MW of combined-cycle capacity owned by merchant generators, as listed in Table 4.[14] This capacity is generally not committed to serving load, and is sold in the spot market or under short-term contracts.

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[13] Table 3 includes generation in the SPP reliability region, plus Nebraska (which is an SPP member, but part of the Midwest Reliability Organization), minus the Oklahoma capacity listed in Table 2. The SWEPCo capacity is included in both compilations. The tabulation of combustion turbines includes only post-1998 combustion turbines.

[14] Some of the modern combustion turbine capacity is also owned by merchant generators.

Table 4: Merchant Combined-Cycle Capacity in and around SPP

Plant	Owner	State	Summer Net MW	Capacity Factor
Oneta Energy Center (a)	Calpine Central LP	OK	886	32%
Evangeline Power Station	Cleco Evangeline LLC	LA	732	32%
Dogwood Energy Facility	Dogwood Energy LLC	MO	614	16%
Eastman Cogeneration Facility	Eastman Cogeneration LP	TX	402	57%
Green Country Energy LLC (b)	Green Country Op Services LLC	OK	263	55%
Kiamichi Energy Facility	Kiowa Power Partners LLC	OK	1,178	51%
Pine Bluff Energy Center	Pine Bluff Energy LLC	AR	192	80%
Union Power Partners LP	Union Power Partners LP	AR	2,020	24%
Hot Spring Power Project	Hot Spring Power Co LLC	AR	642	49%
TOTAL			6,929	37%

Notes:
a) The 886 MW at Oneta Energy Center is net of the new seven-year 200 MW PPA with Xcel Energy's Southwestern Public Service Company, reported in Calpine's 2010 Annual Report.
(b) The 263 MW at Green Country Energy is net of the 520 MW PPA with Public Service Company of Oklahoma which will be ne in effect from June 2012 through February 2022. (Exelon 10-K, p. 295)

As part of the overall compliance strategy, OG&E or PSO may find that it is cost-effective to purchase some of these plants outright, or to purchase their capacity under long-term contracts. A number of the owners of combined-cycle plants have sold all or part of their plants to utilities in recent years, including those in the table below, often at costs well below the cost of building a new gas combined-cycle, which OG&E estimates at $1,003/kW in 2010 dollars, plus financing costs. (OG&E 2011 Integrated Resource Plan, Table 4).

Table 5: Sales of Combined-Cycle Plants in and around SPP

Seller	Plant Name	State	Closing Date	% sold	Capacity (MW)[a]	Acquirer	Purchase Price $M	Purchase Price $/kW
NRG Energy	McClain	Okla.	7/9/04	77%	377	Oklahoma G&E	$160	$425
CLECo	Perryville	La.	6/30/05	100%	831	Entergy LA	$170	$205
Central Mississippi Generating	Attala	Miss.	3/31/06	100%	500	Entergy MS	$88	$176
Calpine	Aries/Dogwood	Mo.	2/7/07	100%	677	Kelson Energy	$234	$345
Cogentrix Energy	Ouachita	La.	5/4/07	100%	904	Entergy AR	$198	$219
Calpine	Acadia Energy	La.	8/17/07	50%	1,376	Cajun Gas Energy	$189	$137
GE Energy Financial Services	Green Country	Okla.	10/2/07	100%	904	J-Power USA Generation	$240	$265
Cogentrix	Southaven Power	Miss.	5/9/08	100%	904	Tennessee Valley Authority	$461	$510
Kelson	Redbud	Okla.	9/30/08	100%	1,338	Oklahoma Gas & Electric	$852	$637
Tennessee Valley Authority	Southaven Power	Miss.	10/6/08	70%	633	Seven States Power	$345	$545
Acadia Power Partners	Acadia 1	La.	Feb '10		580	CLECo	$304	$524
Kelson	Cottonwood	Texas	Aug '10	100%	1,279	NRG Energy	$525	$410
PSEG	Odessa	Texas	1/13/11		1,000	High Plains Diversified Energy	$335	$335
PSEG	Gaudelupe	Texas	1/13/11		1,000	Wayzata Investment	$351	$351
Acadia Power Partners	Acadia 2	La.	4/29/11		580	Entergy LA	$300	$517
Sequent	Wolf Hollow	Texas	5/13/11	100%	720	Exelon	$305	$424
KGen Partners	Hinds	Miss.	2012	100%	520	Entergy AR	$206	$396
KGen Partners	Hot Spring	Ark.	2012	100%	630	Entergy MS	$253	$408

Notes:

a. Summer capacity reported by owner or EIA.

While some of the sales in Table 5 are of plants somewhat remote from Oklahoma (geographically and/or electrically), their costs are indicative of the market value of this technology in the mid-south region. Indeed, areas such as ERCOT, Louisiana, and Mississippi would tend to have higher market prices for power and power plants than the locations in Table 4.

Question 4. Given that Oklahoma currently has a 15% renewable energy goal and is on pace to exceed its goal in as little as three years, what are the possible cost, emission, and reliability impacts of such increased renewable power on current base load generation?

Renewable generation, which in Oklahoma has meant primarily wind generation, is relevant to IECP in at least two ways. First, renewable energy can provide large amounts of energy to replace the existing coal plants, avoiding the need for the expensive environmental retrofits. Unlike other potential replacements for retired coal plants, wind and solar resources produce no pollutants and use no water. Second, renewables (particularly wind) have output that varies from hour to hour, requiring load following and operating reserves that the large coal plants are not well-suited to provide.

Potential for Wind Generation to Replace the Oklahoma Coal Generation

It appears that the Oklahoma utilities could replace a significant share of the output of the FIP-affected units with wind, at attractive costs. Oklahoma and other parts of SPP have enormous potential for wind-farm development. As of July 2010, in addition to the 3,300 MW of wind in service, the SPP transmission interconnection queue included 111 projects, totaling 20,274 MW, plus 7,470 MW of incremental wind development under approved generation interconnection agreements.[15]

An SPP analysis also found that wind generation producing 40% of SPP's energy requirement (about 25,000 MW of wind capacity, producing 100,000 GWh) would be feasible, so long as supporting transmission is constructed.[16] SPP is engaged in major transmission expansions, to bring additional wind from the western part of the region to the load centers in the east. (2010 SPP Transmission Expansion Plan, pp. 33-34) Clean Line Energy's proposed Plains and Eastern merchant transmission project would bring about 7,000 MW of wind from western Oklahoma through the Oklahoma load centers to Arkansas and Tennessee. Clean Line Energy's proposed Grain Belt Express would bring east another 3,500 MW from Kansas and the Oklahoma panhandle.

Of this tremendous potential, OG&E owns 449 MW of wind and has another 332 MW under contract, while PSO has 198 MW of wind under long-term contract. In its 2011 Integrated Resource Plan, OG&E estimates that the energy cost savings from generic wind additions displacing its current marginal energy

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[15] First Status Report OF Southwest Power Pool, Inc., in Response to Order on Interconnection Queue Reform, Docket No. ER09-1254-000, July 30, 2010.

[16] SPP WITF Wind Integration Study, Final Report, Prepared for Southwest Power Pool, January 4, 2010.

supplies—a mix of coal and gas—would have a present value of about $2,600/kW. (OG&E IRP, May 2011, p. 32). Production tax credits ("PTCs"), if they are extended, would provide benefits of another $840/kW, for a total of about $3,440/kW.

The Crossroads Wind Farm, which OG&E is currently building, is expected to cost $1,760/kW; including financing costs, taxes and operating costs, the present value of the Crossroads Wind Farm cost would be about $2,300, indicating that it will be saving OG&E customers about $300/kW without the PTC and $1,140/kW with the PTC. Those benefits estimates do not include the savings from avoiding the environmental compliance costs at the FIP-affected coal plants.[17]

Most of the SPP wind farms for which public cost data are available are similar to those of Crossroads, including:

- Spearville (KS): $261 million for 148.5 MW, or $1,759/kW.
- Central Plains (KS): $181 million for 99 MW, or $1,830/kW.
- Centennial (OK): $200 million for 120 MW, or $1,667/kW.
- Caney River (KS): $350 million for 200 MW, or $1,750/kW.
- Ainsworth (NE): $81.3 million for 50 MW, or $1,626/kW.
- Flat Ridge (KS): $191 million for 100 MW, or $1,905/kW.

A large amount of additional wind capacity is likely to be available at similarly attractive costs, especially as turbine technology improves and production capacity increases. Wind power has no fuel cost and little exposure to post-construction requirements for environmental retrofits.

Currently energy from solar photovoltaic units is more expensive than fossil fuels resources; however, the cost of solar PV continues to drop sharply. Moreover, PV delivers energy at high-load times (sunny summer days) and at the point of use (avoiding line losses and reducing transmission and distribution

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[17] Since the generation mixes for PSO and most Oklahoma utilities are similar to OG&E's mix, additions of wind to other utilities' resource portfolio are likely to be similarly favorable.

loads). Hence, solar PV must be part of a cost-effective resource plan, even if the cost per MWh is currently higher than energy from remote, fossil fuel baseload and variable resources.

Effect of Wind Generation on Coal Generation

Large steam plants, such as the coal plants covered by the FIP, are generally very poor at load following, since they tend to have long warm-up periods, minimum down times between shutdown and startup, minimum up operating periods, slow ramp rates, and low efficiency and high emissions at partial load levels. Those large coal plants do not operate well as part of a heavily wind-powered system.

The SPP WITF Wind Integration Study analyzed the effect of wind generation, up to 20% of SPP energy, on the dispatch of existing power plants. As wind generation increases from the base case to 20% (an increase of 10,800 MW, less than half of the capacity in the 40% wind case), coal plant output would drop by 12%, the number of annual starts would increase by 48%, and the operating output when on line would drop 7%.[18] These changes, let alone the much larger changes in coal-plant dispatch due to still-higher wind penetration, will be hard on the coal plants physically and economically.

Question 5. What operational or financial constraints exist for Oklahoma's emerging wind energy development if greater use of natural gas is not readily available to compensate for the intermittency of wind generation?

Sierra Club has not specifically investigated the adequacy of natural gas fuel supplies for wind integration but is not aware of any evidence that supplies would be constrained for this purpose. Gas supplies are generally tightest in the winter, when electric load and the usage of gas for electric generation are lowest. There is a large amount of underutilized gas generation in Oklahoma, the rest of SPP, and adjacent areas.

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[18] The Wind Integration Study also assumes that the Nebraska nuclear units can be cycled offline. Nuclear plants are not normally allowed to load-follow, for safety reasons. If the nuclear plants cannot follow load, additional coal plants may need to be shut down at low-load periods, resulting in additional start-stop cycles.

It is not clear that additional wind-energy development would increase the use of natural gas. While some additional gas capacity may be needed for effective integration of the wind output, and to replace the inflexible coal plants, wind resources would reduce the use of gas in many hours. The amount of gas that is conserved when the wind is blowing at higher-than-average levels may offset the gas consumed in following variations of wind output.[19]

Alternatives to natural gas for load-following are discussed in the response to Question 6.

Question 6. What options, such as load following generation, are available to integrate intermittent generation into the grid? What is the emission performance of these options?

The most flexible load-following generation resources are storage hydro plants, including pumped storage. The next-best load-following generation resources are gas-fired combustion turbines, operating in simple-cycle mode or as part of combined-cycle plants. Large steam plants, such as the coal plants covered by the FIP, are generally very poor at load following, since they tend to have long warm-up periods, minimum down times between shutdown and startup, minimum up operating periods, slow ramp rates, and low efficiency and high emissions at partial load levels.

Gas-fired plants are likely to provide a large share of the load-following and other integration resources as wind capacity grows in the SPP region. Even if there were to be some concern about the availability of gas for integrating wind resources, other options exist, particularly storage technologies. The dominant utility-scale storage technology has been pumped-storage hydro. Grand River Dam Authority has 260 MW of pumped storage at Salina; nationally, there are about 20,000 MW of pumped storage at 39 facilities. The Salina plant and any future

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[19] Referring to wind and solar resources as "intermittent" is somewhat misleading. "Intermittent" often refers to phenomena that suddenly start and stop. Wind generation does ramp up and down, but wind output from a large wind farm (or a set of wind farms totaling 500 MW) rarely changes by more than 1–2% per minute. Output from any one solar facility can drop quickly as clouds blow in, but summer loads will drop at the same time, and regional solar output will decline gradually as clouds spread over the region. Thus, "variable" describes wind and solar generation better than "intermittent."

pumped-storage plants in and around Oklahoma would integrate well with wind, pumping water into the upper reservoir when wind generation is high and load is low, and rapidly switching off the pumping and switching to generation mode when the wind drops off or load spikes. Hydro-electric plants with no pumping but some storage can also vary output quickly to follow load.[20] Other energy storage technologies that are currently in development and demonstration stages include a variety of battery technologies (including the reuse of retired batteries from electric and hybrid vehicles), flywheels, and compressed air.

Demand-side options can also be helpful in wind integration, including the use of interruptible loads, demand response, load management (e.g., control of electric water heaters), real-time pricing, and the control of battery charging by electric and plug-in hybrid vehicles.

As for emissions, load-following with coal plants (holding the units in warm reserve, ramping them up and down, and operating them at partial load) tends to result in higher emissions of all pollutants per MWh than does stable baseload operation. The same is true for some gas-fired steam plants. Modern combustion turbines and combined-cycle plants are generally able to start up, ramp, and follow load with little increase in emission rates. The effects of storage technologies on emissions depends on the type of generation that supplies the extra energy needed to charge the storage, ranging from excess wind energy at zero emissions to various types of fossil generation.

In addition to load-following capacity, the SPP Wind Integration Study identifies roles for technology (transmission reinforcement, voltage control devices, and dynamic voltage support), and improvements in markets for services from existing resources (separation of regulation-up and regulation-down services, addition of a new 4-hour-ahead market to update the day-ahead commitment).

Question 7. Is the current projected supply of natural gas expected to be adequate to serve the projected natural gas requirements of Oklahoma's regulated electric utilities over the current 20-year planning horizon?

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[20] There are about 800 MW of conventional hydro in Oklahoma, and another 2,300 MW in Kansas, Nebraska, Arkansas, Louisiana and Missouri.

See the response to Question 2. Experience suggests that the supply of natural gas will be adequate to serve the projected natural gas requirements of Oklahoma's regulated electric utilities over the current 20-year planning horizon.

Question 8. How would switching boiler fuel, international usage of natural gas and coal produced in the United States or other factors affect the adequacy of the coal and natural gas supply for Oklahoma's electric utilities over the current 20-year planning horizon? Are there other considerations for potential impacts on the projected natural gas supply for the life of existing plants?

The Sierra Club has no comments at this time on gas and coal supply

Question 9. If regulated utilities were to seek approval of long-term natural-gas supply contracts, what are the appropriate factors for the Commission to consider in determining whether such approval should be granted by the Commission?

The critical issues are the price of the contracts, as compared to current forwards and forecasts, and the gas supply and financial capability of the counterparty.

Question 10. Parties should make comments on any reasonably related issues they believe the Commission should also consider.

The Commission's questions in the NOI did not specifically request comments on the role of energy efficiency in responding to the pending environmental requirements for the FIP-affected coal plants. Energy-efficiency programs funded through and/or administered by utilities have become important components of utility resource planning. If Oklahoma follows the examples of leading efficiency portfolio administrators in the United States and Canada, it should be able to offset a significant percentage of the energy and capacity now provided by the FIP-affected coal plants. Energy efficiency produces no emissions, saves water, uses no fuel, and is not subject to future retrofit requirements.

As discussed in detail below, Oklahoma can easily join the growing number of jurisdictions that are saving one percent of forecast sales per year, after some preparation in 2012 and ramp-up to one-half percent of sales in 2013. That modest level of effort would save most of the energy and more than the capacity contribution of one FIP-affected unit by 2017 and two units by 2022. Continuing the energy-efficiency ramp-up to 2% by 2016, Oklahoma could save the energy output of nearly one and a half of the FIP-affected units and the capacity of two units by 2017 and the energy of about three such units and capacity of four by 2022.

Opportunities abound for Oklahoma's homes and businesses to reduce the amount of electricity consumed to operate appliances and equipment serving practically every end use—particularly lighting, cooling, ventilation, refrigeration, space and water heating, motors and drives, and compressors. Together, these end uses constitute the vast majority of electricity consumption by Oklahoma's residential, commercial, and industrial electricity customers. Today's electricity demand results from millions of past choices about efficiency levels in the equipment and buildings comprising Oklahoma's current capital stock. Future electricity demand depends on the efficiency of the turnover of, and additions to, Oklahoma's capital stock over time.

Efficiency Program Potential

Table 6 summarizes the electric energy savings reported by the State Energy Efficiency Scorecards prepared annually by the American Council for an Energy-Efficient Economy (ACEEE).[21] The 25 states in this table represent all those that were reported to be saving 0.2% or more of their energy sales annually by 2008.

[21] The 2008 Scorecard is the latest available. Assembling and analyzing the date requires about 20 months from the end of the calendar year.

Table 6: Statewide Energy Savings as a Percent of Sales

State	2006	2007	2008
Vermont	1.1%	1.8%	2.6%
Hawaii	0.6%	1.2%	2.0%
Nevada	0.6%	0.7%	1.1%
Connecticut	1.0%	1.1%	1.1%
California	0.7%	1.3%	1.1%
Minnesota	0.6%	0.7%	0.8%
Wisconsin	0.5%	0.7%	0.8%
Rhode Island	1.2%	0.8%	0.8%
Idaho	0.7%	0.4%	0.8%
Iowa	0.7%	0.7%	0.7%
Utah	0.5%	0.5%	0.7%
Massachusetts	0.8%	0.9%	0.7%
Oregon	0.8%	0.9%	0.7%
New Hampshire	0.7%	0.7%	0.6%
Maine	0.6%	0.9%	0.6%
Washington	0.7%	0.7%	0.6%
Arizona	0.2%	0.4%	0.5%
New Jersey	0.3%	0.3%	0.5%
Colorado	0.1%	0.3%	0.4%
Montana	0.5%	0.3%	0.3%
New York	0.6%	0.4%	0.3%
New Mexico	0.0%	0.1%	0.3%
North Dakota	0.0%	0.0%	0.2%
Texas	0.1%	0.1%	0.2%
South Dakota	0.0%	0.0%	0.2%
Florida	0.1%	0.2%	0.2%

In the ACEEE Scorecards, Oklahoma shows up at 0.00%.

Table 7 supplements the data in Table 6 for 2009 and 2010, from various regulatory filings. This table includes data from utilities and other program administrators, from 14 states and the provinces of British Columbia and Nova Scotia. Some of the entries in Table 7 apply to only a portion of the state.[22] Some 2010 results have not yet been reported.

[22] For Oklahoma, the data represent OG&E, PSO and Empire.

Table 7: Energy Savings in 2009 and 2010, from Regulatory Filings

Jurisdiction	2009	2010
California	1.9%	2.0%
Vermont	1.5%	1.9%
Connecticut	0.9%	1.5%
Nevada	1.3%	
Rhode Island	1.2%	
Iowa	1.1%	1.0%
Massachusetts	0.8%	1.1%
British Columbia	0.8%	1.0%
Maine	0.7%	0.8%
New York	0.5%	0.8%
Nova Scotia	0.5%	0.7%
Wisconsin	0.6%	0.5%
New Jersey	0.6%	0.5%
Arkansas	0.2%	0.3%
Oklahoma	0.2%	0.2%
Texas	0.2%	

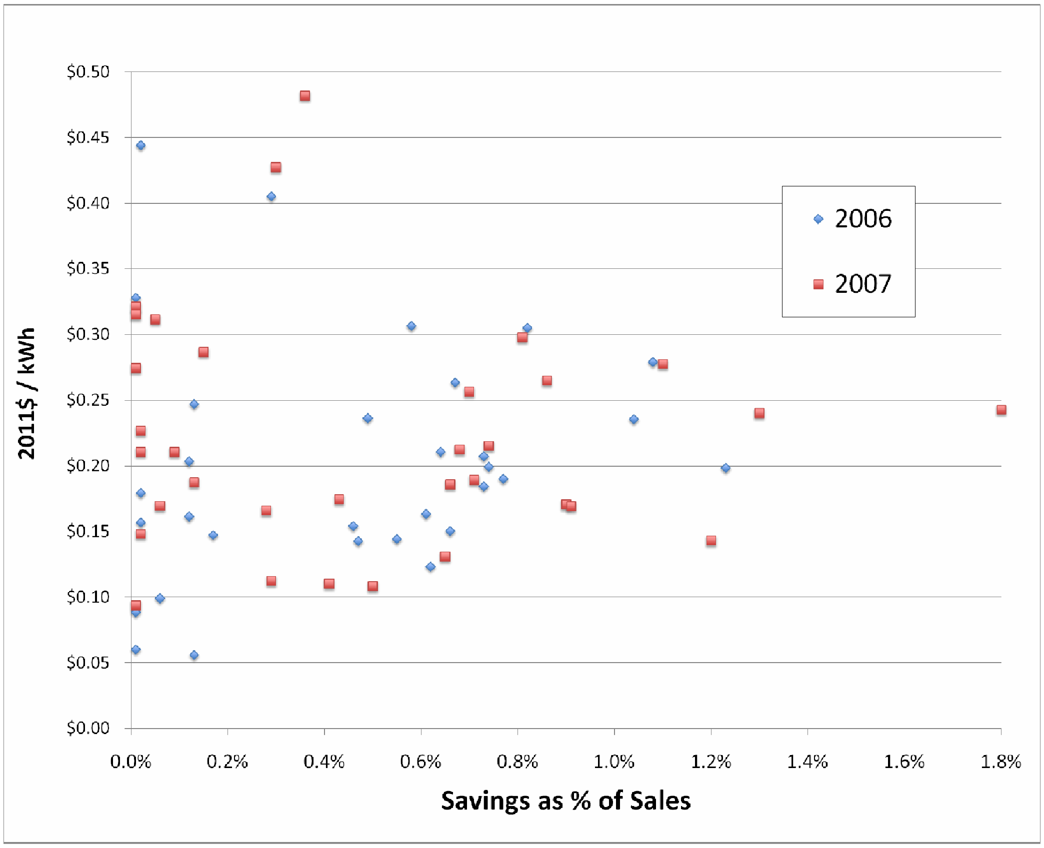
There are a couple of important observations that can be made from the data in Table 6 and Table 7. First, the leading efficiency administrators (including California, Vermont, Connecticut, and Hawaii) have realized annual electric energy savings of more than 1.5% of electric energy sales.[23] Second, jurisdictions that have committed to energy-efficiency have been able to ramp up savings very quickly: Hawaii from 0.6% in 2006 to 2% in 2008, Nevada 0.6% in 2006 to 1.3% in 2009, Arizona from 0.2% in 2006 to 0.5% in 2008.

Plans for 2011 and beyond are even more ambitious, with Massachusetts investor-owned utilities committed to savings of 2.4% annually by 2012 and a total of about 17% of 2020 sales (just from program activities in 2010 through 2020). In late 2010, Oklahoma's neighboring state Arkansas, which is served in part by OG&E and PSO's affiliate SWEPCo, established electric-utility efficiency goals of 0.25% of energy use in 2011, 0.50% in 2012, and 0.75% in 2013 (Docket No. 08-137-U, Order No. 15, December 10, 2010, p. 18).

[23] These incremental annual savings accumulate over time, so that Connecticut's 2006–2010 savings, for example, have reduced 2010 sales by about 6% of sales.

These savings have been quite inexpensive. Leading efficiency program administrators have spent on average about $0.24 to save a kWh each year for an average of about 12 years, or only about 2¢/kWh saved. Figure 1 summarizes the costs reported by ACEEE for 2006 and 2007, plotting the amount of savings against the cost per kWh saved per year.

Figure 1: ACEEE Costs and Savings for States by Year



The cost values in Figure 1 are stated in terms of the cost of saving a kWh each year for the life of the measures installed, which for typical portfolios probably averages between 12 and 15 years. Depending on the number of years and the discount rate assumed, the levelized cost per kWh saved is roughly a tenth of the values in Figure 1. These savings do not just save bulk energy: they also reduce line losses, loads on the T&D system (reducing the need for many types of upgrades), and generating capacity needs. Not only are the costs of energy-efficiency programs quite reasonable over all, but they do not rise much with the scale of the programs; there is little if any upward trend in cost as savings rise in the ACEEE data.[24]

Projections of efficiency savings are more difficult to compile, but Table 8 provides long-term projections for Vermont and Nova Scotia and near-terms plans for five other states. Vermont is planning on saving about 2% of load annual for the next decade, and Nova Scotia somewhat more. Massachusetts is ramping up its efficiency efforts with the goal of reducing load by at least 20% by 2020. Various 2010 filings by the Connecticut utilities project continuing reductions (in peak and/or energy) of around 0.8% annually through 2019. The 1.2% planned savings reported for California probably understate the electricity savings that state's utilities will actually achieve, given their history of substantially exceeding savings targets established by the Public Utilities Commission.

Table 8: Planned Electric Energy-Efficiency Portfolio Savings in Selected Jurisdictions

	Planned Savings As Percent of Sales								
Year	VT	NS	RI	MA	CA	CT	PA	NV	AR
2011		1.2%	1.4%	1.7%	1.2%	1.2%	1.0%	0.9%	0.3%
2012	2.0%	1.6%	1.7%	2.0%	1.2%		1.0%	0.5%	0.5%
2013	2.1%	2.4%	2.1%					0.6%	0.8%
2014	2.1%	2.2%	2.5%						
2015	2.0%	2.3%							
2016	2.1%	2.3%							
2017	2.2%	2.3%							
2018	2.1%	2.2%							
2019	2.2%	2.2%							
2020	2.0%	2.2%							
2021	2.0%	2.2%							

The forecasted cost of these savings is very similar to those shown in Figure 1, in the range of 20¢ to 50¢ of investment per annual kWh saved.

OG&E serves part of western Arkansas, which accounts for approximately 10% of OG&E's 2009 sales. In proceedings before the Arkansas Public Service Commission, OG&E estimated that "it could ramp up to savings of 'slightly less

[24] Jurisdictions savings more than 1% annually over many years are likely to see their costs per annual saved rise into the upper half of Figure 1.

than 1% per year'."[25] OG&E should be able to achieve similar savings in Oklahoma.[26]

Energy-Efficiency Programs for Oklahoma

Oklahoma's electric utilities have two fundamentally different ways to acquire efficiency savings. One set of saving opportunities occurs by influencing transactions that will take place anyway, as people buy new products and equipment and build or renovate homes and businesses. Long-lasting electricity savings from these market-driven transactions are relatively inexpensive to acquire, since costs are limited to the incremental cost of higher-efficiency technologies.[27] If the efficiency resource is not acquired at the time the customer makes an equipment and design decision, it is lost for decades; hence, these are called "lost-opportunity" resources.

The other set of efficiency resources consist of encouraging the replacement and improvement of existing equipment that would otherwise have continued to operate inefficiently. These retrofit investments involve early retirement of existing inefficient equipment (such as removing functioning but inefficient lighting fixtures and installing high-efficiency equipment in their place), as well as installation of supplemental equipment and materials (such as insulation, weatherstripping, and controls). Retrofitting a technology is almost always more expensive than installing the equipment with the same efficiency in the first place, since it involves the full cost of the new equipment and installation labor (and often greater complexity in installation). Nonetheless, retrofit opportunities constitute a large reservoir of cost-effective electricity savings, since most buildings and many pieces of equipment will operate inefficiently for decades unless someone takes the initiative to improve them.

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[25] Arkansas Public Service Commission: Docket No. 08-137-U, Order No. 1 (December 10, 2010), page 12.

[26] PSO's affiliate SWEPCo also serves a portion of Arkansas and must meet the same targets.

[27] The windows of opportunity to influence purchase and construction decisions tend to be very brief, and will not reopen until the end of new inefficient or equipment's or building's useful life. Efficiency savings from market-driven transactions are therefore considered "lost-opportunity" resources in the industry.

Unlike lost-opportunity resources tied to customers' construction and purchase decisions, the timing of retrofit investments in existing buildings and equipment is purely discretionary. Utilities can choose the pace of retrofit investment to meet specific resource goals, by deciding what fraction of the buildings and equipment to treat each year.

At this time, Oklahoma has the opportunity to avoid very large near-term capital investments by reducing load, to moderate the total reliance on gas generation over time, and reduce the upward pressure on customer bills. These considerations argue for pushing ahead with energy-efficiency programs as quickly as feasible, maximizing both the fraction of customers who participate in the programs and the savings each participant realizes. These goals will require aggressive targeted marketing, close technical assistance, and financial incentives covering most or all of the installed costs of efficiency measures.

The Oklahoma utilities could easily replicate best practices in financial, marketing, and technical strategies employed by the nation's leading program administrators and achieve comparable results. In 2010, OG&E started offering a limited portfolio of residential and commercial efficiency programs in Oklahoma, which it is only committed to running through 2012. Even this very tentative first step is projected to reduce 2012 energy sales by 144 GWh or 0.63 percent. Extending the Arkansas programs to Oklahoma should raise those targets, to about 1.6 percent of sales by 2013. OG&E could continue ramping up its initial pilot programs over the next few years to reach the levels achieved by the leading efficiency portfolios.

While the other Oklahoma utilities appear to be starting somewhat behind OG&E in this regard, PSO at least can build on staff experience of its affiliate SWEPCo in Arkansas, and all the utilities can learn from the program designs and materials developed in Arkansas and other jurisdictions. The most effective forum for this rapid learning would be a statewide collaboration of the utilities and other interested parties. One important benefit of a statewide approach would be the development of consistent program designs, minimizing confusion for the many HVAC contractors, equipment distributors, builders and other trade allies who are essential for the success of energy-efficiency programs.

The one-percent savings level, while above that in the average state, would not reflect a full response to the challenges facing Oklahoma. Continuing the ramp-up to energy efficiency to 2% by 2016, Oklahoma could reduce requirements by 4,300 GWh/year and 1,000 MW by 2017 and 9,200 GWh/year and 2,100 MW by 2022. These savings are equivalent to the energy output of nearly one and a half of the FIP-affected units and the capacity of two units by 2017 and the energy of about three such units and capacity of four by 2022.

This ramp-up of energy savings would dovetail well with the other resource options discussed in the answers to preceding questions, with increased use of gas and purchased power replacing the coal units in the near term, with the reliance on gas gradually being reduced by the energy-efficiency programs and development of additional wind generation.