BEFORE THE
OKLAHOMA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR COMMISSION AUTHORIZATION OF A PLAN TO COMPLY WITH THE FEDERAL CLEAN AIR ACT AND COST RECOVERY; AND FOR APPROVAL OF THE MUSTANG MODERNIZATION AND COST RECOVERY	**)))))))**	**CAUSE NO. PUD 201400229**

Direct Testimony of Tyler Comings

Public Version

On Behalf of Sierra Club

December 16, 2014

Table of Contents

List of Figures and Tables

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Tyler Comings. I am a Senior Associate with Synapse Energy Economics, Inc. ("Synapse"), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please summarize your work experience and educational background.

A I have nine years of experience in economic research and consulting. At Synapse, I have worked extensively in the energy planning sector, including work on integrated resource plans, costs of regulatory compliance and economic impact analyses. I have provided consulting services for various other clients including for the U.S. Department of Justice, District of Columbia Office of the People's Counsel, District of Columbia Government, Maryland Office of the People's Counsel, New Jersey Division of Rate Counsel, West Virginia Consumer Advocate Division, Illinois Attorney General, Nevada State Office of Energy, Sierra Club, Earthjustice, Citizens Action Coalition of Indiana, Consumers Union, Energy Future Coalition, American Association of Retired Persons, and Massachusetts Energy Efficiency Advisory Council.

I have provided testimony on electricity planning and economic impacts in the District of Columbia, Indiana, Kentucky, Maryland, and New Jersey.

Prior to joining Synapse, I performed research in consumer finance for Ideas42 and economic analysis of transportation and energy investments at Economic Development Research Group.

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Exhibit TFC-1.

Q **Please describe Synapse Energy Economics.**

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and 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, attorneys general, environmental organizations, federal government agencies, and utilities.

Q **On whose behalf are you testifying in this case?**

A I am testifying on behalf of Sierra Club.

Q **Have you submitted testimony in other recent regulatory proceedings?**

A Yes. I have submitted testimony on utility planning proceedings before the Indiana Utility Regulatory Commission (Cause 44339) and the Kentucky Public Service Commission (Case No. 2013-00259). I have also submitted testimony on the proposed merger between Exelon Corporation and Pepco Holdings, Inc. in three jurisdictions: District of Columbia, Maryland, and New Jersey.

Q **Have you testified in front of the Oklahoma Corporation Commission previously?**

A No, I have not.

Q **What is the purpose of your testimony?**

A I was retained by Sierra Club to review the application of Oklahoma Gas & Electric (OG&E or "the Company") for approval and cost recovery of the retrofit of Sooner units 1 and 2, conversion of Muskogee units 4 and 5 to natural gas steam, construction of new combustion turbines ("CT's") at the Mustang plant site, among other plant investments.

My testimony focuses on evaluating the reasonableness of the assumptions used in the Company's supporting analysis and how those assumptions impact the net present value of the proposed action. My testimony also presents alternatives to the Company's plan. I focus on environmental risks and associated costs that the Company either failed or insufficiently considered in justifying the proposed retrofit the Sooner plant. I present alternative modeling assumptions and summarize the modeling results produced by my colleague, Rachel Wilson and Jennifer Tripp. My colleague, Dr. Jeremy Fisher, discusses the Company's planning methodology and compliance with the proposed 111(d) carbon rule.

Q Are there any exhibits that accompany your testimony?

A Yes. I am attaching my resume as Exhibit TFC-1 and data responses I refer to as Exhibit TFC-2.

II. SUMMARY OF TESTIMONY AND CONCLUSIONS

Q How much is the Company proposing to spend for this proposed plan?

A The capital cost of the proposed plan is "approximately $1 billion."[1] This does not include operating costs associated with these capital investments.

Q What is the Company proposing for Sooner units 1 and 2?

A As part of its chosen "Scrub/Convert" plan, the Company has determined that a "scrubber" or flue gas desulfurization technology ("FGD"), Activated Carbon Injection ("ACI"), and low nitrogen oxide ("NOx") Burners are needed on the Sooner units. These retrofits are expected to cost $525 million.[2]

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[1] Direct Testimony of Sheri Richard, page 2, line 23.
[2] Data Response OIEC 3-12_Att71, costs are in 2014 dollars.

Q **What is the Company proposing for Muskogee units 4 and 5?**

A As part of the same "Scrub/Convert" plan, the Company has determined it will convert Muskogee units 4 and 5 to burn natural gas instead of coal. These projects are expected to cost $71 million.[3]

Q **What are your findings regarding the Company's chosen plan and justification?**

A The Company's decision to retrofit Sooner units 1 and 2 is not economically justified given the following:

1. The Company's own analysis shows that retrofitting Sooner is more costly than converting it to natural gas, in most scenarios and sensitivities (including the Company's carbon dioxide ("CO_2") sensitivity). In my analysis, I show that converting Sooner to natural gas is less costly than the Company's proposed retrofits in every scenario and sensitivity except for one (High Gas).

2. The Company did not adequately assess carbon cost risk despite the likelihood of carbon regulation as evidenced by the recent release of the proposed Clean Power Plan.

3. The Company failed to address other future environmental risks and costs associated with Sooner, mainly the high likelihood that the Company will need to install additional controls to reduce NOx emissions, such as selective catalytic reduction ("SCR") controls.

4. The Company neglected to consider additional wind generation on its system despite their attractive costs and pervasive availability in the region.

5. The Company's modeling methodology is fundamentally flawed since the Company did not conduct capacity expansion modeling, review other

[3] Data Response OIEC 3-12_Att71, costs are in 2014 dollars.

alternatives, or include incremental energy efficiency after 2021, despite modeling a 30-year analysis period.

Q **Does the Company's Base scenario represent a reasonable future?**

A No. As I discuss in greater detail in Section III-C, the Company's Base scenario excludes any costs associated with emitting carbon dioxide—essentially assigning a zero cost for carbon regulation over the next 30 years. A carbon cost greater than zero would favor dispatch of less carbon-intensive resources over coal generation relative to what the Company is currently assuming in the Base scenario.

Q **Is it reasonable for the 30-year analysis of the Company's fleet to neglect the potential cost of installing and maintaining Selective Catalytic Reduction technology on its coal units?**

A No. As I outline in depth in Section III-D, there are a host of existing, proposed, and emerging environmental regulations that could obligate the Company to install selective catalytic reduction technology, including an update to the Regional Haze state implementation plan, a ruling that OG&E violated Clean Air Act New Source Review requirements, and the recently proposed lower ozone national ambient air quality standards ("NAAQS"). Given these statutory and regulatory drivers, it is unreasonable not to include these costs when evaluating whether to retrofit the Sooner units within the 30-year analysis period.

Q **Did you perform an alternative analysis of the Company's plans?**

A Yes. Using PCI Gentrader modeling conducted by my colleague Witness Rachel Wilson and PROMOD modeling conducted by Witness Jennifer Tripp, I analyzed an alternative scenario that includes a higher carbon price that reflects EPA's estimate for 111(d) compliance costs—which I consider a "high bound" carbon price scenario, and using the Company's Base scenario natural gas prices ("Synapse Base Gas/EPA CO_2"), the installation of selective catalytic reduction on Sooner, and the addition of new wind to OG&E's system.

Q How do your adjusted results compare OG&Es' results?

A As discussed in detail in Section IV, the adjusted results show that the net benefit of scrubbing Sooner as compared to converting it to natural gas is negative in most sensitivities—*i.e.*, it is more costly to scrub them than to convert them. Figure 1 and Table 1 show that the net present value revenue requirement ("NPVRR")—that is, the discounted cost to ratepayers—of retrofitting Sooner units 1 and 2 is higher in all scenarios except under the Company's "High Gas" scenario. Under the Company's CO_2 scenario, which I believe is appropriate to include in the Base scenario, converting Sooner units 1 and 2 is $1 billion lower in cost than retrofitting the units. While these numbers include the assumption that the Company is required to install an SCR on Sooner in 2020, even without the addition of an SCR, the Convert option is more attractive in most scenarios (see Figure 1).[4]

[4] Synapse also ran the Company's CO2 scenario with the addition of SCR variable operating costs. However, the results showed a minimal change in NPVRR based on variable costs alone (approximately $20 million or less than 0.1% of NPVRR difference). Therefore, in the interest of time, we did not run the increased variable costs due to the SCR in the results presented in Figure 1

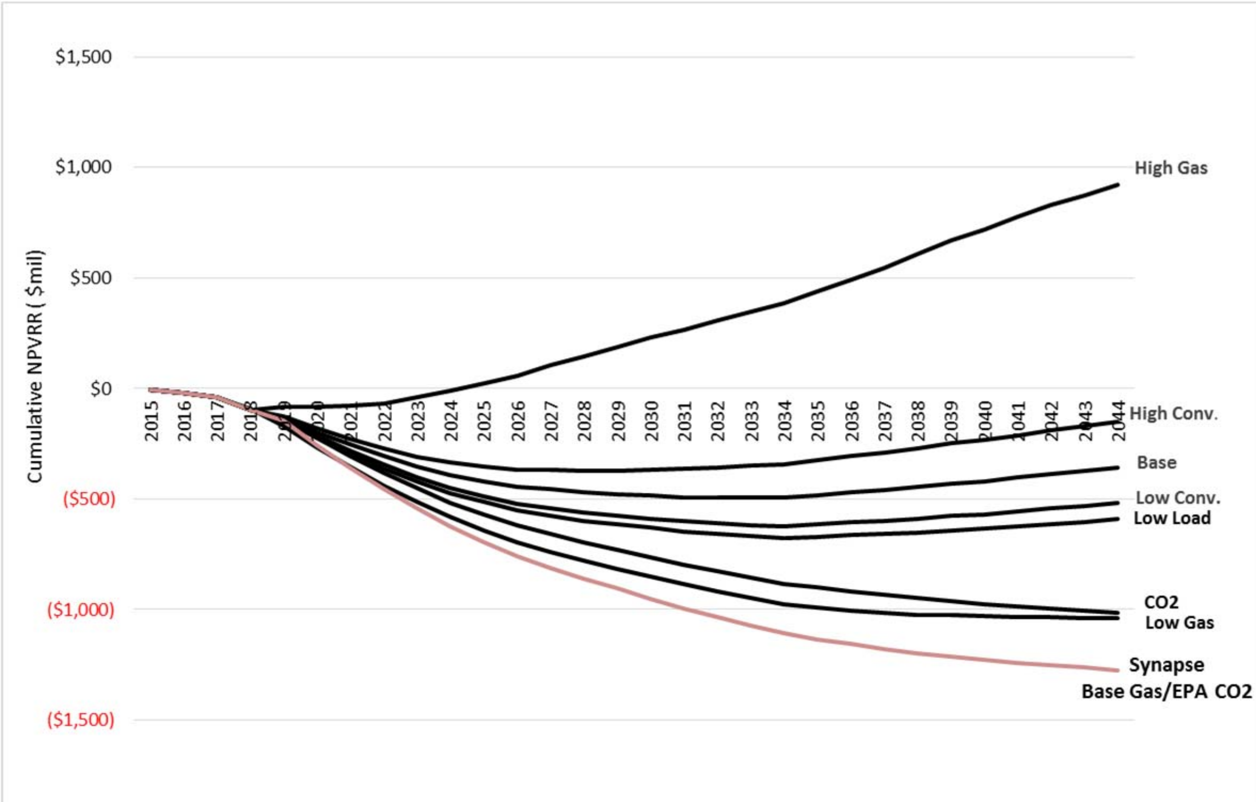

Figure 1: Cumulative Net Benefit (Cost) of Retrofitting Sooner 1&2 with SCR and Synapse Base Gas/EPA CO_2 Scenario (NPVRR, $2014 mil)

Table 1: Cumulative Net Benefit (Cost) of Retrofitting Sooner 1&2 with SCR and Synapse Base Gas/EPA CO_2 Scenario

	NPVRR without SCR ($2014, mil)		NPVRR with SCR ($2014, mil)	
Scenario/Sensitivity	Benefit of Retrofit	Retrofit Breakeven Year	Benefit of Retrofit	Retrofit Breakeven Year
Base	$133	2038	-$357	Never
CO_2	-$525	Never	-$1,015	Never
High Conversion	$340	2031	-$150	Never
Low Conversion	-$30	Never	-$520	Never
High Gas	$1,413	2021	$923	2025
Low Gas	-$548	Never	-$1,038	Never
Low Load	-$100	Never	-$590	Never
Synapse Base Gas/ EPA CO_2	-$837	Never	-$1,274	Never

Q Did you find that the addition of wind reduced costs over the analysis period?

A Yes. I estimated the change in NPVRR that would occur for each scenario if OG&E built out its wind generation using bid prices received by the Company.[5] Since the costs of wind are [redacted] than the market price, the addition of wind onto the system [redacted]—shown in [redacted] For example, adding more wind to OG&E's portfolio [redacted] the NPVRR in OG&E's base scenario by more than [redacted]. In almost all years and scenarios/sensitivities, the additional wind generated [redacted] The High Gas, CO_2, and Synapse scenarios generated the largest [redacted] in NPVRR due to new wind since market prices for energy are [redacted] in those scenarios. Thus, wind is shown to be an [redacted] both higher gas and higher carbon costs.

[redacted]

[redacted]

[5] Data Response OIEC 5-8_Att CONFIDENTIAL
[6] Data Response 1-37_Att1 CONFIDENTIAL

Q Should the Commission adopt your adjusted analysis as presenting the "correct" NPVRR?

A No. I have mostly followed the Company's methodology in order to show where reasonable changes in assumptions to account for environmental risks would lead to a different investment decision—namely the conversion of Sooner. Section V explains flaws in the Company's modeling methodology. My colleagues, Witnesses Jennifer Tripp, Rachel Wilson and Jeremy Fisher also explain flaws with the Company's modeling.

Q What are your recommendations for the Commission?

A I recommend that the Commission deny the Company's application for approval to retrofit Sooner units 1 and 2. The Company's own modeling shows that the retrofit option is barely economical compared to the Convert option in its Base scenario—a scenario that subjects its ratepayers to significant risk as it includes no compliance costs for carbon or other environmental regulations—and it is not the least cost alternative in the majority of sensitivities and scenarios the Company considered. Second, when an appropriate range of sensitivities are considered, converting the Sooner units to natural gas—part of the Company's "Convert" portfolio—is likely less expensive and less risky over the long-term than retrofitting the units. Finally, the pursuit of additional wind generation would [redacted] the customers' costs across all scenarios and sensitivities due to its [redacted] relative to the SPP energy market prices.

<u>III. THE COMPANY'S DECISION TO RETROFIT THE SOONER UNITS IS LIKELY UNECONOMIC</u>

A. BACKGROUND ON OG&E'S ANALYTICAL FRAMEWORK

Q Why is the Company seeking approval for major investments at Sooner and Muskogee plants?

A As described by Witness Leon Howell, the Company is seeking a suite of investments at these coal units in order to comply with:

- Sulfur dioxide limits under the EPA's Regional Haze Federal Implementation Plan, which would require installation of new controls (such as flue gas desulfurization or “FGD”), retirement, or conversion to natural gas.

- Nitrous oxide limits under the Regional Haze State Implementation Plan, which would require installation of new controls (such as low NOx burners), retirement, or conversion to natural gas.
- Mercury emission limits under the EPA’s Mercury Air Toxics Standard, which would require installation of new controls (such as activated carbon injection), retirement, or conversion to natural gas.

The Company must meet regulatory requirements and provide capacity to meet its SPP planning reserve requirement. In light of these requirements, the Company conducted an economic analysis in its 2014 IRP in order to weigh the options of retrofitting, retiring, or converting Sooner units 1 and 2 and Muskogee units 4 and 5. My testimony focuses on this analysis and resulting decisions made by the Company to retrofit Sooner units 1 and 2 while converting Muskogee units 4 and 5 to natural gas. The Company refers to this decision as the “Scrub/Convert” portfolio.

Q What options did the Company evaluate for Sooner and Muskogee plants?

A The Company started with five portfolios (shown in Table 2) representing combinations of future options for the Sooner 1 and 2 (combined) and Muskogee 4 and 5 (combined) units, including retrofit, convert to gas, or replace with a new natural gas combined cycle plant (“NGCC”).

Table 2: OG&E's Portfolios for Sooner 1&2 and Muskogee 4&5[7]

OG&E Portfolio	Sooner 1&2	Muskogee 4&5
Scrub/Convert	Retrofit	Convert to Gas
Scrub	Retrofit	Retrofit
Convert	Convert to Gas	Convert to Gas
Replace	New NGCC	New NGCC
Scrub/Replace	Retrofit	New NGCC

Q How did the Company evaluate the cost of each of these portfolios?

A The Company assembled the fixed costs of each option including costs of retrofits, gas conversions, and construction of new plants associated with the portfolios above. The Company also developed a separate future build-out of natural gas units to maintain capacity as units retire and as peak demand.[8] The chosen "CT Spread" build-out alternative includes a mix of new NGCC's and CT's that OG&E intends to build over the 30-year analysis period when there is a capacity shortage. This assumed build-out is the same for every portfolio.

As a member of the Southwest Power Pool ("SPP") Integrated Marketplace ("IM"), OG&E now purchases its energy requirements from that market while its units compete with others in the market for generation to serve the market at large. Thus the load-serving and generating operations of OG&E are effectively separate. With that in mind, OG&E tested the five portfolios under future scenarios and sensitivities of market prices, including[9]:

- **Base**
- **CO_2** – assuming a carbon price beginning in 2020
- **High Conversion –** assuming a high conversion of SPP coal units to natural gas

[7] Direct Testimony of Leon Howell, page 5, Figure 1.
[8] The Company modeled three buildouts: "CC", "CT", and "CT Spread" (a mix of new CC's and CT's) and concluded that CT Spread was the lowest cost.
[9] The Company refers to Base, High Conversion and Low Conversion as "scenarios" and the others market price projections as "sensitivities".

- **Low Conversion -** assuming a low conversion of SPP coal units to natural gas
- **High Gas –** assuming a 50% higher natural gas price
- **Low Gas –** assuming a 25% lower natural gas price
- **Low Load –** assuming lower OG&E peak load

The Company developed SPP energy price forecasts for each of these scenarios/sensitivities using the PROMOD model. The Company then dispatched its units against these market prices using the PCI Gentrader model. As my colleague, Ms. Wilson, explains in more detail, this methodology is flawed because it implicitly assumes that OG&E's units have no effect on the market prices, despite comprising approximately 13% of the energy on the SPP market.[10]

Q How did OG&E compare the value of its compliance portfolios?

A The Company conducted a market analysis of each of the five portfolios under the scenarios listed above. This analysis incorporates the net present value of revenue requirements (NPVRR) which includes the following costs (+) and then subtracts revenue made on the SPP energy market (-):

+ Fixed operating costs
+ Variable operating costs (including fuel)
+ Financing of capital investments
+ Market purchases
+ Power purchase agreements (e.g. wind)
- Market revenue

The fixed operating costs and capital investments are fixed in each portfolio and thus do not change between scenarios. In each portfolio, available units are dispatched in the PCI Gentrader model if their variable costs are lower than the scenario/sensitivity market price at that hour. Therefore, variable operating costs

[10] SPP Market Monitoring Unit. 2013 State of the Market Report. May 19, 2014. Page 2. Available at: http://www.spp.org/publications/2013%20SPP%20State%20of%20the%20Market%20Report.pdf

(including fuel costs and variable operations and maintenance) and market revenues change between scenarios/sensitvities.

B. THE COMPANY'S OWN ANALYSIS DEMONSTRATES THAT IT DID NOT SELECT THE LEAST-COST ALTERNATIVE UNDER MOST SENSITIVITIES AND SCENARIOS.

Q What were the results of the Company's portfolio analysis?

A The Company found that the Scrub/Convert portfolio was the lowest cost in the base scenario. The Scrub (i.e. scrubbing all four units) and Convert portfolios (i.e. converting all four units) were all within $0.1 billion NPVRR of Scrub/Convert under this scenario (see Table 3). The difference between the Scrub/Convert and Convert portfolios is the retrofit or conversion of Sooner, respectively. Therefore, the difference in NPVRR between Scrub/Convert and Convert is the net benefit (or cost) of retrofitting Sooner units 1 and 2.

Q What is the least expensive portfolio in each scenario?

A Table 3 shows the least cost portfolio in each scenario in grey shading. The Scrub/Convert portfolio (i.e,. conversion of Muskogee and retrofit of Sooner) is the lowest cost in the Base scenario but not in any other scenarios/sensitivities. The Scrub portfolio is the lowest cost in the High Conversion and High Gas scenarios. The Convert portfolio is the lowest cost in four of the seven scenarios/sensititivies: CO_2, Low Conversion, Low Gas, and Low Load.

Table 3: OG&E Results by Scenario (NPVRR, $2014, billion)[11]

Scenario/Sensitivity	Scrub/ Convert	Scrub	Convert	Scrub/ Replace	Replace
Base	**$22.4**	$22.4	$22.5	$23.2	$24.2
CO_2	$26.4	$27.0	**$25.9**	$26.9	$26.8
High Conversion	$22.4	**$22.3**	$22.7	$23.0	$24.0
Low Conversion	$22.2	$22.4	**$22.2**	$23.3	$24.3
High Gas	$25.8	**$24.7**	$27.2	$26.6	$28.7
Low Gas	$20.3	$21.0	**$19.7**	$21.3	$21.7
Low Load	$22.1	$22.4	**$22.0**	$23.2	$24.2

Q Does this matrix show that OG&E's conclusions are robust?

A No. Utilities typically conduct a sensitivity analysis in order to "stress test" portfolio options under different uncertainties, such as natural gas and carbon prices. The chosen Scrub/Convert portfolio fails to be lowest cost under most scenarios and sensitivities and is therefore not a robust conclusion as it is only the least cost option under the Base scenario, which includes no margin of error with regard to certain risks, and is out competed by other alternatives under the Company's various scenarios and sensitivities.

Q Do you think the Commission should question the usefulness of OG&E's base scenario?

A Yes. First, the Base scenario includes no margin of error for certain likely risks, since it included zero cost to comply with future carbon or other future environmental regulations. Second, the NPVRR for each of the Company's portfolios are extremely close to each other in terms of total costs, as shown in Figure 3 below. The chosen Scrub/Convert plan's costs are nearly identical to the "Scrub" plan, and are only 0.6% lower than the costs of the Convert plan. Given that the Base scenario has no risk for carbon and other environmental regulations built into it for the next three decades, and considering the small NPVRR

[11] Data Response OIEC 3-12_Att86. The Company also conducted sensitivities for High and Low capital costs but these sensitivities do not change market prices. Convert is lower in the Low Conversion case but appears even with Scrub/Convert due to rounding.

variations, the Commission should be wary of putting too much weight (if any) on this Base scenario. Third, as I discuss later, the riskiness of the Base scenario is shown by the looking at the cumulative NPVRR by year, in which the Scrub/Convert does not become expensive than the Convert portfolio until 2038.

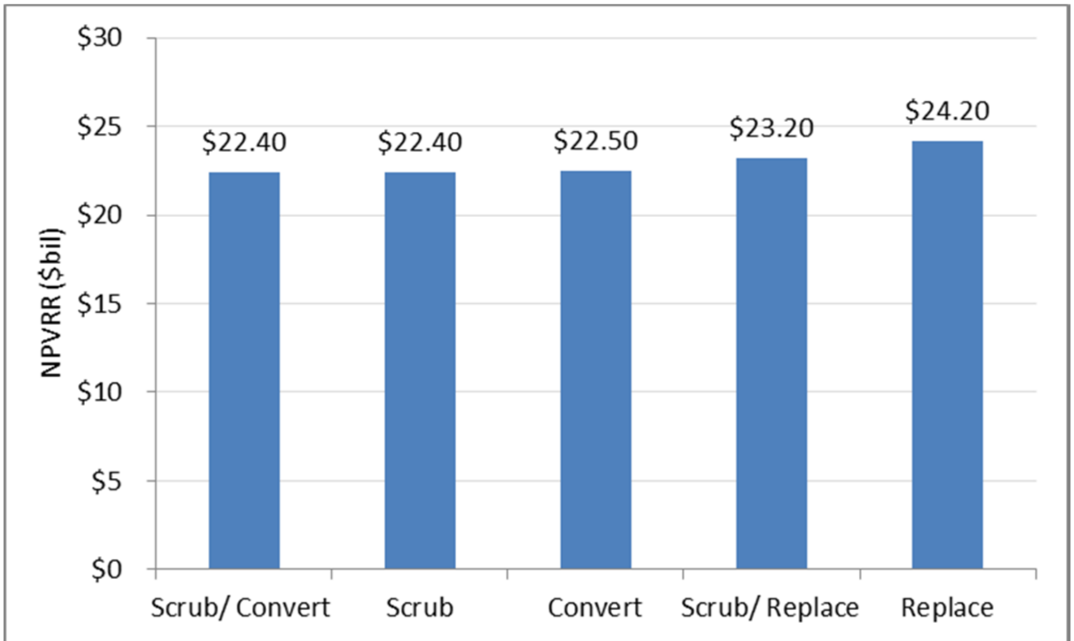

Figure 3: OG&E Base Case Scenario Results (NPVRR, $2014, bil)[12]

Q How long does it take for retrofitting Sooner to become less expensive than the converting it to natural gas in the Company's base scenario?

A Figure 4 and Table 4, below, demonstrate the riskiness of OG&E's selected portfolio. Figure 4 illustrates the cumulative net benefit of retrofitting Sooner units 1 and 2 in each price scenario run by the Company. An NPVRR difference below zero indicates that retrofit of Sooner (i.e. Scrub/Convert) is more costly than conversion to natural gas (i.e. Convert) up to and including the given year.

For example, in 2038, the net benefit of retrofit in the Base scenario goes from negative to positive—this indicates that the portfolio "breaks even" in 2038. Put differently, retrofitting Sooner units 1 and 2 does not become the least expensive alternative in the Base scenario until 2038. This result means that ratepayers

[12] Id.

would have to wait for 24 years for the Company's chosen portfolio to pay off. Given the myriad of regulatory uncertainties the Sooner units will face over the next 24 years, retrofitting Sooner units 1 and 2 is a risky portfolio choice.

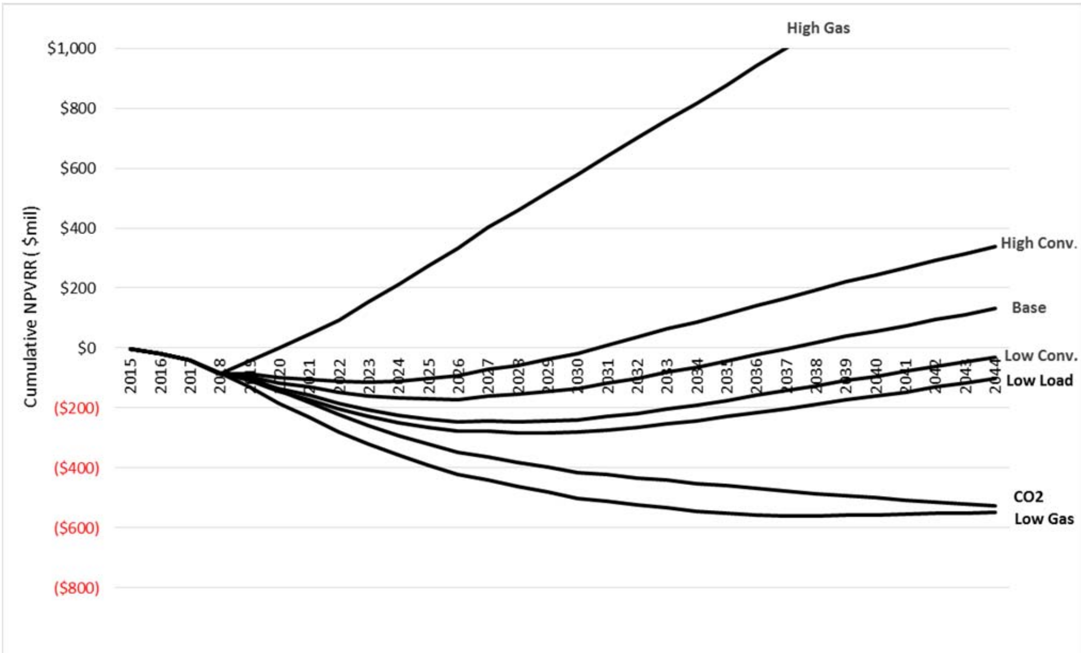

Figure 4: Cumulative Net Benefit (Cost) of Retrofitting Sooner 1&2 (NPVRR, $2014 mil)

Table 4: Cumulative Net Benefit (Cost) of Retrofitting Sooner 1&2[13]

Scenario	Benefit of Retrofit ($2014, NPVRR)	Retrofit Breakeven Year
Base	$133	2038
CO_2	-$525	None
High Conversion	$340	2031
Low Conversion	-$30	None
High Gas	$1,413	2021
Low Gas	-$548	None
Low Load	-$100	None

[13] Id.

Q **Is the Company's High Gas scenario a reasonable "high bound" for gas prices?**

A No. OG&E uses the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2014 for its base natural gas prices. However, it inflates these prices by 50% to arrive at the High Gas prices, resulting in natural gas prices that are higher than any of the price scenarios run by the EIA (including a run that assumes natural gas resources are limited)—see Figure 5. Therefore, the Commission should consider the High Gas scenario an overly optimistic future for evaluating the retrofit of Sooner.

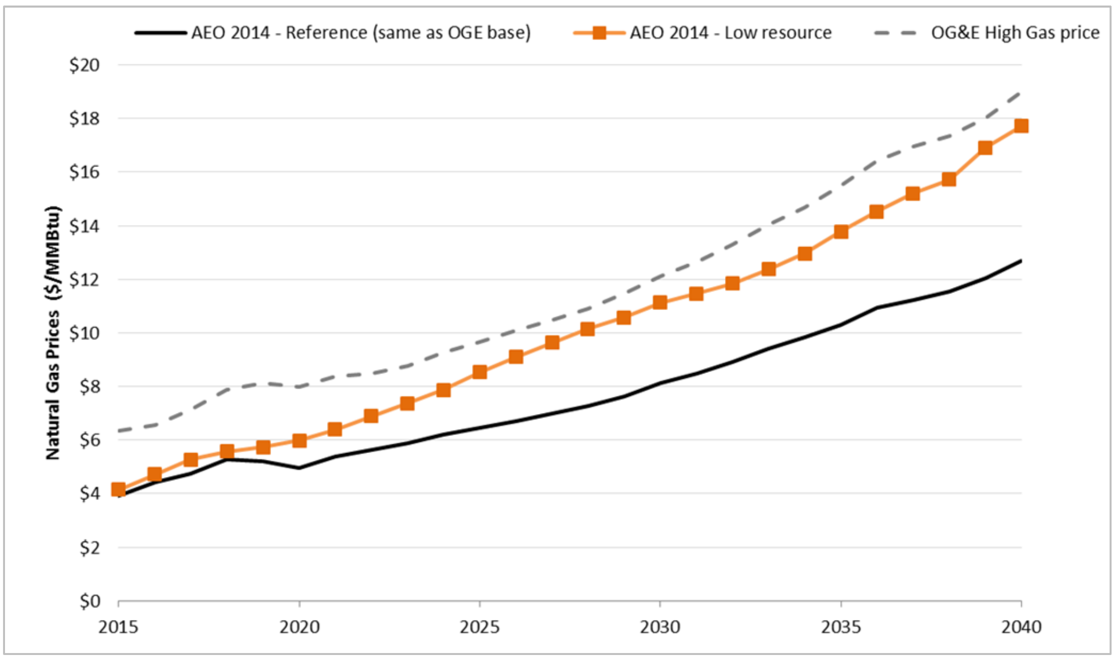

Figure 5: OG&E Base and High Gas Prices ($/MMbtu)[14]

[14] OIEC 1-25_Att1 and EIA AEO 2014 data, available here: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=0-AEO2014&table=62-AEO2014&region=3-18&cases=ref2014-d102413a

Q For those scenarios where converting Sooner to natural gas is lower cost than retrofitting Sooner, how long does it take for conversion to become cheaper?

A Conversion is always cheaper than retrofit in the CO_2, Low Gas, Low Conversion and Low Load scenarios. This indicates that converting Sooner units involves low risk since it maintains lowest cost status throughout.

Q Why did OG&E choose the Scrub/Convert portfolio?

A Retrofitting Sooner is the lowest cost option in the Company's base scenario, yet it is not the lowest cost option in any of the other scenarios and sensitivities--including the Company's CO_2 scenario. The Company claims that it chose this option because it "[p]roduces the lowest reasonable cost with due consideration to the uncertainty associated with the SPP IM energy prices, fuel prices, and future regulatory risks."[15]

Q Did the Company adequately assess future regulatory risks?

A No. As I will discuss later, the Company only included a carbon cost in one sensitivity and ignored other future environmental compliance costs entirely. These are gross omissions of future risk in the Company's analysis. Even under the Company's Base scenario—with no carbon costs or other future environmental compliance costs—choosing to retrofit Sooner does not become economic until 2038. Given the myriad of risks and costs that could occur between now and then, it is unreasonable to conclude that retrofitting Sooner is economic.

Q Does the Convert portfolio allow the Company to avoid future regulatory risks?

A Yes. The conversion of Sooner units 1 and 2 would allow the Company to avoid nearly $500 million in costs associated with the scrubbers at issue in this case. As I will discuss in greater detail below, converting Sooner would also avoid

[15] Direct Testimony of Leon Howell, p. 5, lines 12-14.

potentially high regulatory costs in the future that the Company has not accounted for, such as additional NOx emission controls.

C. THE COMPANY DID NOT ADEQUATELY ACCOUNT FOR CARBON COST RISK

Q Does the Company's Base scenario represent a reasonable future?

A No. The Company's base scenario excludes any costs associated with emitting carbon dioxide—essentially assigning a zero cost for carbon regulations over the next 30 years. A carbon cost greater than zero would favor dispatch of less carbon-intensive resources over coal generation relative to what the Company is currently assuming in the Base scenario.

Q Did the Company consider the potential for costs associated with carbon dioxide emissions in its economic analysis?

Yes, but only in one sensitivity called "CO_2." The other sensitivities modeled by the Company assume that there is a zero carbon cost for the next 30 years. In the one CO_2 sensitivity, the assumed price is $15 per ton of CO_2 in 2020 increasing to $18 per ton in 2024. The Company claims it only included carbon costs as a sensitivity rather than in its Base Case because "the 2014 Annual Energy Outlook Early Release assumes that there are no explicit federal regulations to limit greenhouse gas emissions."[16] This reasoning is flawed because the 2014 Annual Energy Outlook (AEO 2014) Reference case explicitly includes only known laws and regulations at the time of the forecast. The AEO 2014 documentation explains that:

> There may be interest in alternative cases that reflect updates or extensions of current laws and regulations that the AEO2014 Reference case excludes. Areas of particular interest include…laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act that require the EPA to issue

[16] Exhibit LCH-1, p. 35.

> or revise regulations if it finds that an environmental quality target is not being met.[17]

Q Is it reasonable to assume that emissions of CO_2 will remain cost and risk-free in most scenarios and sensitivities for the next three decades?

A No, it is unreasonable to assume there will be no carbon regulation in the next 30 years in any "base case." The EPA's Clean Power Plan proposes to regulate carbon emissions from existing power plants and is only the first proposed regulation by the agency to do so under its requirement to regulate greenhouse gases. This proposal was issued on June 2, 2014 with issuance of a final rule expected in 2015. The proposed rule calls for carbon emission rate or mass-based, state-specific targets starting in 2020. Dr. Fisher explains the rule and its impacts in more detail.

Q Do other utilities in Oklahoma incorporate a carbon price in a base case?

A Yes. Public Service Company of Oklahoma assumed a carbon price in its 2012 IRP base case and its parent company, American Electric Power, continues to do so in its other service territories in more recent proceedings.[18] While PSCO's carbon price forecast is lower than OG&E's, it is incorporated in PSCO's base case along with low and high carbon sensitivities.

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[17] U.S. Energy Information Adminsitration. Annual Energy Outlook 2014. P. IF-3.
[18] PSO 2012 IRP, p.45. Available here: http://occeweb.com/pu/PSO%202012%20IRP.pdf and 2015 SWEPCO IRP: Description of Studies and Study Assumptions, slide 11. Available here: https://www.swepco.com/global/utilities/lib/docs/info/projects/SWEPCOIntegratedResourcePlan/SWEPCO_LA_IRP_Presentation_Jan-30-14.pdf

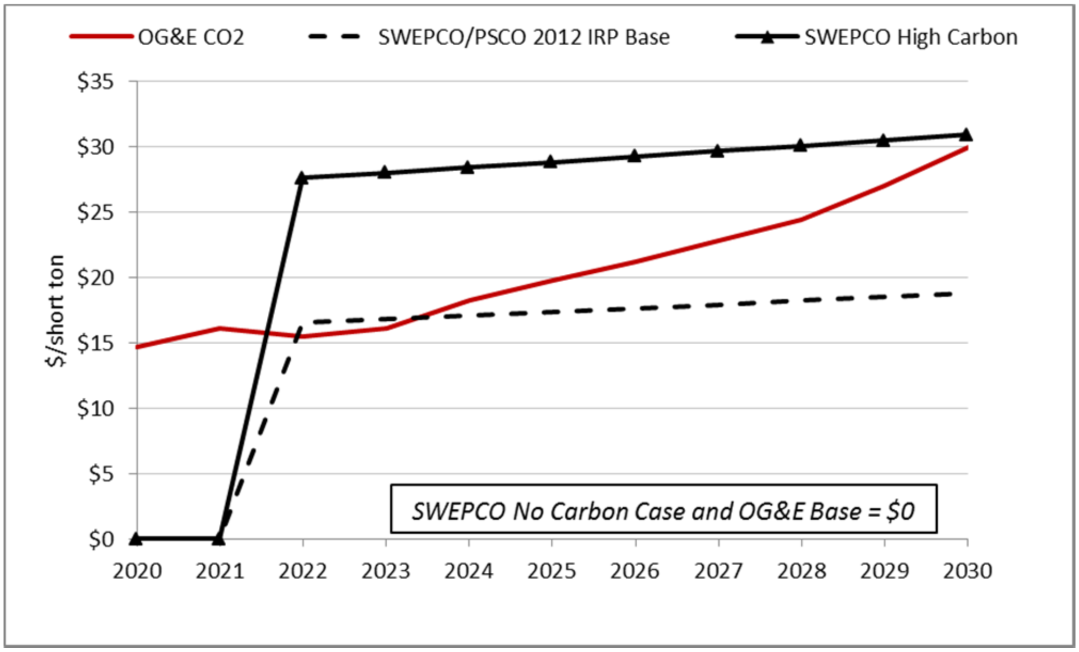

Figure 6: OGE Carbon Sensitivity Compared to SWEPCO and PSCO IRP Assumptions ($/ton)[19]

Q Do other Commissions expect utilities to examine CO_2 costs in resource planning?

A Yes. For example, the Arkansas Public Service Commission recently ordered utilities to assign a non-zero avoided regulatory cost for carbon emissions as part of energy efficiency cost-effectiveness analysis.[20] The Indiana Utility Regulatory Commission, citing the risk of carbon regulation to the economic viability of a coal unit, determined that a utility that assumed a zero carbon cost in its base case would have to assume responsibility for future carbon regulation should carbon regulation render the unit non-economic.[21]

[19] Id.

[20] See Arkansas PSC, Docket 13-002-U, In the Matter of the Continuation, Expansion, and Enhancement of Public Utility Energy Efficiency Programs in Arkansas, Order No. 1, at p.19.

[21] Indiana Utility Regulatory Commission. August 14, 2013. Verified Petition of IPL for Approval of Clean Energy Projects…etc.. Cause 44242. Final Order. Page 36. http://www.in.gov/iurc/files/44242order_081413.pdf

Q Why should the Company consider a carbon price in its base case?

A Over the long term, the inclusion of a carbon cost in utility resource modeling protects OG&E and its ratepayers from exposure to the costs from greenhouse gas regulations. Even if the Company cannot estimate costs to comply with the Clean Power Plan at this time, it should explore cost uncertainties going forward by running sensitivities with multiple carbon prices to account for different possible compliance costs. If OG&E fails to include a reasonable carbon price forecast in its base case, the result will be a carbon-intensive fleet more vulnerable to escalating costs under the Clean Power Plan or future carbon regulations and legislation.

Q Do you think the Company's CO_2 sensitivity represents a reasonable "base case"?

A Yes. The Company's CO_2 sensitivity includes a carbon price developed by the Company based on the difference in costs of operating coal units compared to natural gas units ("NGCC"). This cost negates the dispatch spread between natural gas and coal generation—similar to the second building block in the Clean Power Plan. Dr. Fisher discusses this in more detail, and describes why the Company's CO_2 scenario is a reasonable starting point.

E. THE COMPANY IGNORED FUTURE ENVIRONMENTAL COMPLIANCE COSTS IN ITS ANALYSIS.

Q How are impending environmental regulations important to the case at hand?

A In addition to the regulation of greenhouse gases, a suite of final and proposed EPA regulations will require coal-burning power plants to install pollution controls.[22] The environmental retrofits at issue in this case are required for compliance with the Regional Haze and Mercury and Air Toxics Standards ("MATS") rules. There are numerous other environmental regulations that are expected in the next few years. Just as the MATS and Regional Haze rules impose

[22] Note: a proposed rule from the EPA is a draft version of the rule made available for public comment, and is usually a strong indicator that a final rule with similar provisions will follow.

costs on the existing coal fleet, as made apparent by the retrofits at issue in this docket, other pending rules are also expected to have moderate to significant impacts on the costs of operating and owning coal units.

Q Aside from the Regional Haze and MATS, are future environmental rules reflected in the economic analysis conducted by the Company?

A No. With the exception of dealing with Regional Haze and MATS, the Company has neglected important costs of compliance with proposed and pending environmental regulations, effectively assigning them a zero cost. Forthcoming environmental regulations will impose costs on the Company's coal-fired assets. By neglecting pending environmental regulations, the Company biases its economic analysis towards those projects with ignored but likely future costs, unnecessarily putting its members at risk.

Q Which environmental regulations has the Company not included in this analysis?

A Rules governing air quality, water quality, and coal combustion residual disposal are all expected to impose moderate to significant costs at existing coal-fired facilities. These rules include:

- finalized and emerging National Ambient Air Quality Standards ("NAAQS"),
- the re-issuance of the Cross State Air Pollution Rule ("CSAPR"),
- the proposed rules governing the disposal of Coal Combustion Residuals ("CCR"),
- reasonable further progress requirements under the Regional Haze rule
- provisions of the Clean Water Act governing cooling water intake structures under section 316(b) of that act, and
- proposed Clean Water Act effluent limitation guidelines ("ELG") for scrubber and ash handling wastewater at steam electric generating units.

Q What other environmental compliance risks does the Company face?

A The federal government and other organizations (including Sierra Club) have sued OG&E for violations of the Clean Air Act New Source Review provisions. If the federal government and/or these organizations prevail in this litigation, OG&E would face costly environmental control upgrades at the Sooner plant.

Q Does the Company discuss any environmental risks associated with each rule listed above?

A Yes, but the Company ultimately ignores this risk. The Company's 2014 Integrated Resource Plan (IRP) has a section entitled "Future Environmental Compliance Risks, in which it discusses environmental risks associated with NAAQS, CSAPR, CCR, and 316(b)."[23] Ultimately, the Company decides not to factor the risks associated with these finalized and pending regulations in its economic analysis.

Q Should the Company ignore the risks associated with these rules until it knows with absolute certainty what they will require?

A No. Until each rule is finalized and the state and EPA determine compliance mechanisms for electric generating units that violate these rules, the exact timing and impact of these rules is unknown. However, the Company should have evaluated proxy costs for reasonable bounding cases based on scenarios of implementation of the rules especially given that draft or final rules are already available in many instances.

Q Please briefly describe the purpose and impact of the proposed Cooling Water Intake Rule.

A On March 19, 2014, EPA released a final rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.[24] Under this rule, EPA set new standards reducing the impingement and entrainment of aquatic

[23] Exhibit LCH-1, p. 14-19.
[24] 33 U.S.C. § 1326.

organisms from cooling water intake structures at new and existing electric generating facilities.

The final rule provides that:

- Existing facilities that withdraw more than two million gallons per day ("MGD") would be subject to an upper limit on fish mortality from impingement and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 MGD would be required to conduct an entrainment characterization study for submission to the Director to establish a "best technology available" for the specific site.

Q Did the Company estimate costs of the Cooling Water Intake Rule?

A Yes. A previous study commissioned by the Company estimated a compliance cost of [redacted], including [redacted] for Sooner units 1 and 2.[25]

Q Were these costs factored into OG&E economic analysis?

A No.[26]

Q Please briefly describe the proposed Coal Combustion Residuals rule.

A Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments; regulations governing the structural integrity and leakage from these installations vary. On June 21, 2010, EPA proposed regulation of ash and flue gas desulphurization wastes, or "coal combustion residuals" (CCR) as either a Subtitle C "hazardous waste" or Subtitle D "solid waste" under the Resource Conservation and Recovery Act ("RCRA").[27]

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[25] Data Response Sierra 1-16_Att1_Confidential
[26] Data Response Sierra 1-16a.ii. "No, the costs were not included in the environmental compliance plan."
[27] 75 Fed. Reg. 35127. June 21, 2010.

Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would implement minimum requirements for dam safety at impoundments.

Under a "solid waste" Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners and/or groundwater monitoring, and require standards for long-term stability and closure care.

Q Did the Company estimate potential compliance costs of the Coal Combustion Residuals ("CCR") rule?

A No. In the 2014 IRP, the Company claims that the CCR rule could impose costs on its fleet:

> The CCR rule could require additional investment in the existing coal plants depending on the option that is included in the final rule. The CCR rule could restrict OG&E's ability to manage its coal ash through beneficial re-use, thus increasing the cost of managing coal ash.[28]

However, when asked if the Company had estimated these costs, it responded that it had not:

> OG&E has not prepared any studies of the potential cost of compliance with the proposed. This is a proposed rule which could change significantly before finalization and as such, the final requirements and how they affect OG&E's units and what those requirements would actually cost, is unknown at this time.[29]

Q. Please briefly describe the purpose and impact of National Ambient Air Quality Standards ("NAAQS").

A. NAAQS set minimum air quality standards that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are located throughout the U.S., or through air

[28] Exhibit LCH-1, p. 14.
[29] Data Response Sierra Club 1-17.

quality dispersion modeling. If an area is found to be violating a particular NAAQS, the state is required to adopt a plan with enforceable requirements to reduce emissions from sources contributing to the violation such that the NAAQS are attained and maintained.

EPA has established short-term and/or annual NAAQS for six pollutants: sulfur dioxide ("SO_2"), nitrogen dioxides ("NO_2"), carbon monoxide ("CO"), ozone, particulate matter (measured as particulate matter less than or equal to 10 micrometers in diameter ("PM_{10}") and particulate matter less than or equal to 2.5 micrometers in diameter ("$PM_{2.5}$")), and lead. EPA is required to periodically review and evaluate the need to strengthen the NAAQS if necessary to protect public health and welfare. For example, EPA recently proposed a more stringent NAAQS for ozone based on the latest science regarding health effects.

Q Which NAAQS will likely have the greatest impact on the Company's coal-fired power plants at issue in this case?

A The 8-hour Ozone NAAQS is likely to have the greatest impact on the Muskogee and Sooner units due to the cost of the controls that may be required to help meet compliance obligations.

Q Please briefly describe the 8-hour Ozone NAAQS.

A The 8-hour ozone NAAQS is intended to protect public health and welfare from the dangerous effects of exposure to ground-level ozone. These effects include harm to the respiratory system, aggravation of asthma and other lung diseases, and premature death.[30]

In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb (parts per billion) to 75 ppb—which was still less stringent than recommended by EPA's panel of science advisors. On September 16, 2009, in response to numerous petitions for reconsideration, EPA announced that it would reconsider the 75 ppb

[30] U.S. Environmental Protection Agency Fact Sheet on Ozone and Health, November 25, 2014, available at: http://www.epa.gov/airquality/ozonepollution/pdfs/20141125fs-health.pdf

standard. In January 2010, EPA proposed lowering the 75 ppb primary ozone standard to between 60 and 70 ppb.

On September 2, 2011, however, the Obama Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the Agency's regular 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone was due in 2013 and EPA did in fact begin its review late last year.

On November 25, 2014, EPA released its proposal to strengthen the 8-hour ozone NAAQS to a standard in the 65 to 70 ppb range, based on extensive scientific evidence about ozone's negative effects.[31] EPA is also taking comments on whether a 60 ppb standard would be appropriate.

Several counties in Oklahoma are still not meeting the less stringent 2008 ozone standard of 75 ppb. It appears likely that EPA will designate additional areas in Oklahoma as non-attainment for the new standard when it is finalized.[32] In particular, Cherokee and Sequoyah counties, which border Muskogee County, where the Muskogee plant is located, are currently exceeding a 70 ppb standard based on 2011-2013 monitoring data (there is no ozone monitor located in Muskogee County) and other nearby counties are also exceeding the 70 ppb standard. [33] There are no ozone monitors in Noble County, where the Sooner plant is located, but neighboring Kay County exceeds both the proposed 70 ppb standard and the existing 2008 standard of 75 ppb, as does Creek County, which has the next closest ozone monitor. This more stringent ozone standard will likely drive significant additional NO_X emission reduction requirements, such as selective catalytic reduction technology, on the Muskogee and Sooner coal-fired power plants.

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[31]U.S. Environmental Protection Agency National Ambient Air Quality Standards for Ozone, proposed rule at: http://www.epa.gov/airquality/ozonepollution/pdfs/20141125proposal.pdf

[32]See US EPA, 2014. Counties Violating the Primary Ground-level Ozone Standard: http://www.epa.gov/airquality/ozonepollution/pdfs/20141126-20112013datatable.pdf

[33] *Id.*

Q Please briefly describe the purpose and impact of the Cross State Air Pollution Rule.

A The Cross State Air Pollution Rule ("CSAPR"), issued in July 2011, addressed Clean Air Act requirements concerning the interstate transport of air pollution. CSAPR established the obligations of 28 states, including Oklahoma, to reduce emissions of nitrogen oxides and/or sulfur dioxide that significantly contribute to another state's $PM_{2.5}$ and ozone non-attainment problems. CSAPR was subsequently stayed by the U.S. Court of Appeals for the District of Columbia on December 30, 2011 and then vacated on August 21, 2012. However, on April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit's decision and remanded the matter. On October 23, 2014, the D.C. Circuit granted EPA's request to lift the stay on CSAPR and to toll all compliance deadlines by three years (reflecting the delay caused by the litigation). The rule and its requirements have now been restored to the status that would have existed but for the stay, albeit three years later. Compliance with Phase 1 of CSAPR now begins on January 1, 2015, while compliance with Phase 2 will begin on January 1, 2017.

Q Did the Company estimate future costs associated with existing or proposed NAAQS?

A No. In the 2014 IRP, the Company claims that the NAAQS rule could impose costs on its fleet:

> As of the end of 2013, no areas of Oklahoma had been designated as non-attainment for pollutants that are likely to affect OG&E's operations. However, in recent years, monitored ozone levels in Oklahoma have been close to a NAAQS exceedance level and this assessment is reviewed each year and measured against the standard that is currently in effect.[34]

However, when asked if the Company had estimated these costs, it responded that it had not:

> No. There are proposed rules for some of the NAAQS, which are pending finalization and in some cases have been pending for 4 years.

[34] Exhibit LCH-1, p. 14.

> These rules could change significantly before finalization and as such, the final requirements and how they affect OG&E's units and what those requirements would actually cost, is unknown at this time.[35]

When asked if it had estimated costs in light of the new proposed ozone standards, the Company replied that it had "not evaluated the impact of a future, potential revised ozone standard."[36]

Q Did the Company estimate future costs associated with CSAPR?

A No. In the 2014 IRP, the Company claims that the CSAPR rule could impose additional costs on its fleet:

> The low NOx combustion equipment being installed for regional haze also will help meet the CSAPR requirements contained in the Supplemental Rule. At this point, it is not clear if those measures by themselves will be enough to satisfy CSAPR or if OG&E will have to consider installing additional controls or purchasing emission credits.[37]

However, when asked if the Company had estimated these costs, it responded that it had not:

> OG&E did not conduct cost's studies specifically for CSAPR compliance. Cost[s] were already known from OG&E Regional Haze SIP plan. Compliance with the final Supplemental Rule was determined to be achieved through the use of Low NOx Burner installations on Regional Haze affected units and Muskogee Unit 6.[38]

Q How will the Ozone NAAQS and the reinstatement of CSAPR impact the Company's coal-fired power plants?

A Nitrogen oxides are a precursor of ozone, meaning that areas that are not attaining the ozone standards will seek the most effective controls for sources of precursors. Since large emissions sources such as coal-fired generating stations contribute disproportionately to emissions of these precursors and can effectively reduce these emissions by installing post-combustion controls such as SCR

[35] Data Response Sierra Club 1-18.
[36] Data Response PUDKC 3-2.
[37] Exhibit LCH-1, p. 14.
[38] Data Response Sierra Club 1-19.

technology, I assume that if areas of Oklahoma within the dispersion area of Sooner plant or Muskogee 6 are found to be in non-attainment for the new ozone standard, the state and EPA could require rigorous NOx controls at these units to meet the regional standards.

Similarly, if the reinstated interstate transport rule requires additional reductions in NOx from sources in Oklahoma, then large sources such as the Sooner and Muskogee plants could be required to either install controls or purchase NOx allowances at high prices. Further, it should be noted that CSAPR was designed to prevent interstate air pollution that causes non-attainment problems based on the 1997 ozone standard. If CSAPR were updated to take into account new, more stringent $PM_{2.5}$ and Ozone NAAQS, I'd expect that the next version of CSAPR will lead to additional NOx reductions being required on sources like Sooner and Muskogee.

These rules could entail the addition of new nitrogen oxides emissions controls at the Sooner units and at Muskogee unit 6. SCRs on Sooner units 1 and 2 would cost $195 million per unit.[39]

Q Are there other regulatory drivers that could require the Company to install an SCR on remaining coal units?

A Yes. An update of the Regional Haze rule could result in a call for further emissions reductions. In fact, the Company directly acknowledges this possibility:

> The second planning period commences in 2019. It is anticipated that, during the second planning period, additional reductions of emissions affecting visibility may be required, or reductions may be required from additional sources, beyond those regulated in the first planning period.[40]

The Company further acknowledges that pending litigation in a Clean Air Act New Source Review case could require SCR after 2019 among other controls:

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[39] This is based on the Company's OG&E Sooner BART Determination, p A-8 (referred to in Burch testimony, p. 7) inflated to 2014 dollars.
[40] Exhibit LCH-1, p. 16.

> If OG&E does not prevail, the plaintiffs could seek to require the installation of selective catalytic reduction to control NOx emissions at all five coal-fired units, and they could seek to require the installation of an additional SO2 scrubber at Muskogee Unit 6. In light of the current pace of the litigation against OG&E and the amount of time that similar litigation has taken, it seems unlikely that these measures could be required before the beginning of 2019.[41]

Q Why is it not sufficient for the Company to determine the cost-effectiveness of the retrofits under its current obligations under the Regional Haze and MATS rule only?

A Complying with the first phase of Regional Haze and MATS rules will not satisfy all of the Company's likely future compliance obligations. With the exception of estimating costs for MATS and the most recent round of Regional Haze, the Company has neglected important costs of compliance with proposed and pending environmental regulations, effectively assigning them a zero cost. The Company should examine a wider range of compliance alternatives, review risks to the Company's coal fleet, and examine these issues in light of still-avoidable costs at its coal units. By neglecting pending environmental regulations, the Company biases its economic analysis towards those projects with ignored but likely future environmental compliance costs, unnecessarily putting its ratepayers at risk.

Such an evaluation is incomplete because it ignores relevant planning information that the Company's management knows or should know, and could put ratepayers at risk for the costs of capital expenditures that, when considered as part of a whole, might not be cost-effective. Instead, the Company is pursuing a piecemeal approach, requesting cost recovery for a single upcoming cost (i.e., MATS and Regional Haze) rather than considering the full costs to ratepayers of continuing to operate the units. Without factoring in the full range of known and likely costs that ratepayers would have to bear, it is not possible to develop a least-cost portfolio, or assure that the costs associated with the instant case will not be stranded well before the Sooner units have fully depreciated.

[41] Data Response PUDKC 1-4a.

Q Is it reasonable for the 30-year analysis of the Company's fleet to neglect the potential cost of SCR on its coal units?

A No. There are a host of existing, proposed, and emerging environmental regulations that could obligate the Company install SCR technology, including an update to Regional Haze, a finding that OG&E violated the Clean Air Act New Source Review standards, and the recently proposed lower ozone NAAQS. Given these statutory and regulatory drivers, it is not reasonable on the Company's part to ignore these potential costs when evaluating portfolios over a 30-year period.

F. INSTALLATION OF AN SCR INCREASES THE COSTS OF THE COMPANY'S CHOSEN PORTOFLIO.

Q How did you address OG&E's failure to consider the impact an SCR would have on the economic viability of its proposed retrofits?

A I estimated the NPVRR results with the addition of SCR installation costs at Sooner units 1 and 2 in 2020, based on the likelihood that (as discussed above) additional NOx reductions will be required at these units. I incorporated the Company's previous estimate for Sooner SCR capital costs ($195 million per unit, adjusting for inflation to 2014 dollars)[42] and annual fixed operations and maintenance (O&M) into the Company's estimate of fixed costs. The results in Figure 7 and Table 5 show that the Scrub/Convert is more costly than Convert in every price scenario except for High Gas.

The Company's original Base scenario of retrofitting Sooner without an SCR broke even in 2038. My updated estimates show that the retrofit investment *never* breaks even except in the High Gas sensitivity, which has limited value as discussed previously.

[42] Direct Testimony of Robert Burch, p. 7, Table 1. The implied cost of SCR from the table ($178 million per unit) was adjusted for inflation from 2008 dollars.

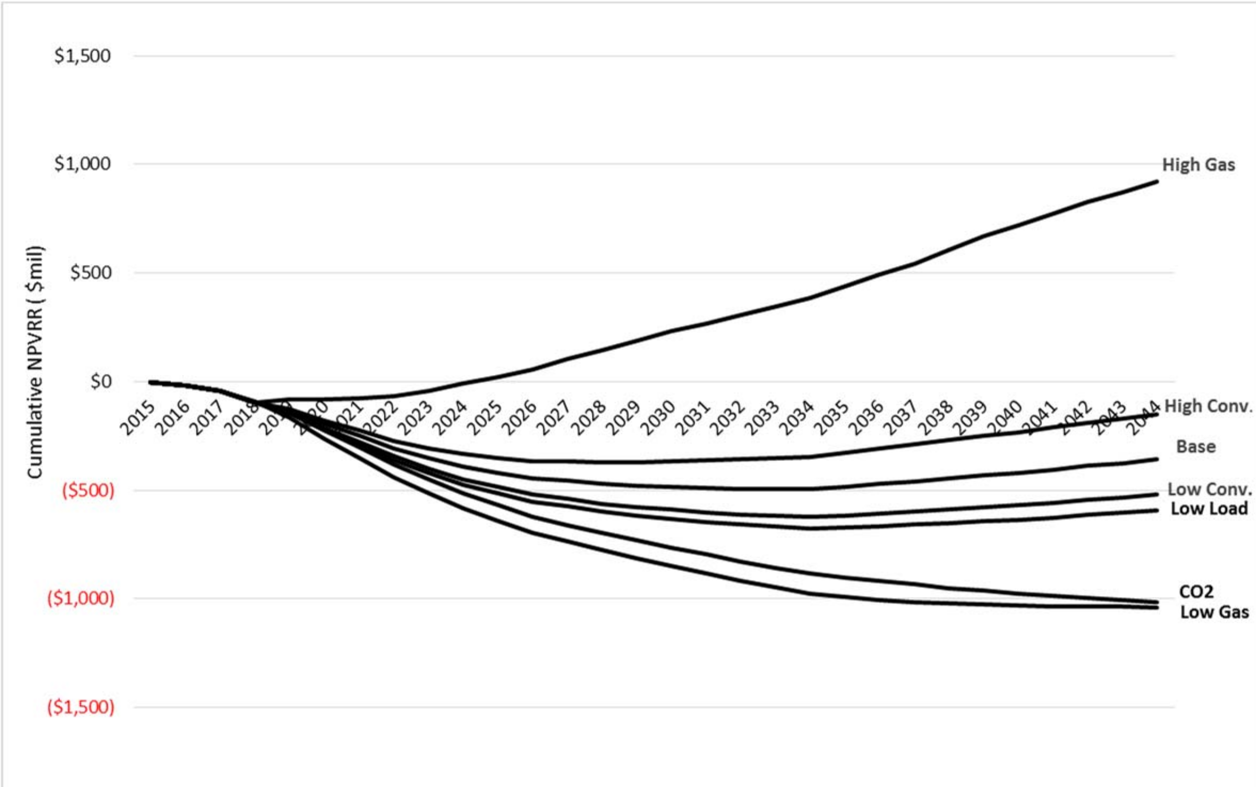

Figure 7: Cumulative Net Benefit (Cost) of Retrofitting Sooner 1&2 with SCR (NPVRR, $2014 mil)[43]

Table 5: Cumulative Net Benefit (Cost) of Retrofitting Sooner 1&2 with SCR[44]

	Company's Estimates (NPVRR, $2014 mil)		Adjusted Estimates (NPVRR, $2014 mil)	
Scenario	**Benefit of Retrofit**	**Retrofit Breakeven Year**	**Benefit of Retrofit**	**Retrofit Breakeven Year**
Base	$133	2038	-$357	None
CO_2	-$525	None	-$1,015	None
High Conversion	$340	2031	-$150	None
Low Conversion	-$30	None	-$520	None
High Gas	$1,413	2021	$923	2025
Low Gas	-$548	None	-$1,038	None
Low Load	-$100	None	-$590	None

[43] Data Response 3-12_Att86. SCR costs are from Direct Testimony of Robert Burch, p. 7, Table 1.
[44] Id.

Q Did you do the same analysis with regard to costs OG&E is likely to incur because of other environmental regulations, such as ELG, CCR, and 316b?

A No. The Company did not provide cost estimates for these rules except for rule 316b. Ideally, OG&E would have taken all costs into account in its economic analysis. I focused on costs of installing an SCR since this is likely much larger than the costs of compliance with the other future rules and, therefore, represents the largest risk to the Company. However, I would encourage the Company to include cost estimates for all future rules in forward-looking analyses.

Q What are the key risks associated with the Sooner retrofit projects?

A The Sooner retrofits carry the following risks: 1) that market prices will not be sufficient to justify operating the unit (i.e. the unit is not dispatched), 2) that market prices will not provide sufficient revenue to cover the fixed costs of the retrofit and other future capital (i.e. the Company will have stranded investments), 3) that significant incremental costs will be required for the unit to comply with future environmental regulations, and 4) that, because the dispatch price of Sooner plant is highly dependent on fuel costs, the cost of coal may rise faster than expected by the Company.

IV. <u>ALTERNATIVE MODELING RESULTS</u>

A. A PROPOSED ADDITIONAL SCENARIO

Q What steps did you take to address the issues with the Company's analysis that you've outlined above?

A As discussed above, the Company's analysis included the following key flaws that make the Sooner retrofits look artificially attractive: 1) it failed to incorporate a carbon price into its base case, 2) it ignored other, potentially significant environmental compliance costs, and 3) it ignored energy resources that would be lower cost than replacing the Sooner units with a new natural gas facility.

I developed an alternative scenario that addresses each of these flaws.

Q Did you analyze this alternative scenario using the Company's models?

A Yes. I submitted an alternative carbon price to Witness Tripp to run using PROMOD to develop an alternative price scenario—the "Synapse Base Gas/EPA CO_2" scenario. This alternative price scenario includes a carbon price that was based on the EPA 111(d) shadow price for the SPP and ERCOT region (discussed in detail by Dr. Fisher). Replicating the Company's methodology, Ms. Wilson then ran this price scenario in PCI Gentrader to dispatch OG&E's units against this new SPP market scenario. (Ms. Wilson discusses this modeling methodology in more detail in her testimony.)

Q Do you think the Synapse Base Gas/EPA CO_2 scenario should be considered a "base case"?

A In this case, the Company's original CO_2 scenario actually represents a reasonable "base case." However, the Company may be subject to higher costs to comply with the proposed Clean Power Plan or other future carbon regulations. Dr. Fisher puts forth the EPA shadow carbon prices as a reasonable high bound, since the price assumes fewer coal retirements or conversions to natural gas then will occur under the Company's plans.

Q What were the initial results of the Synapse Base Gas/EPA CO_2 scenario?

A This scenario generated the lowest net benefit (i.e. highest net cost) of the Company's chosen portfolio (Scrub/Convert) when compared to the Convert portfolio. As shown in Figure 8 and Table 6, the Synapse scenario generates the highest cost for retrofitting Sooner when compared to the Company's original scenarios (in black lines). The Synapse scenario generates a net cost of $784 million for the retrofit of Sooner, compared to a net cost of $525 million in the Company's CO_2 scenario. Since the Company's original results were unadjusted here, the "breakeven" years have not changed in the Company's base scenario, the retrofit still breaks even in 2038.

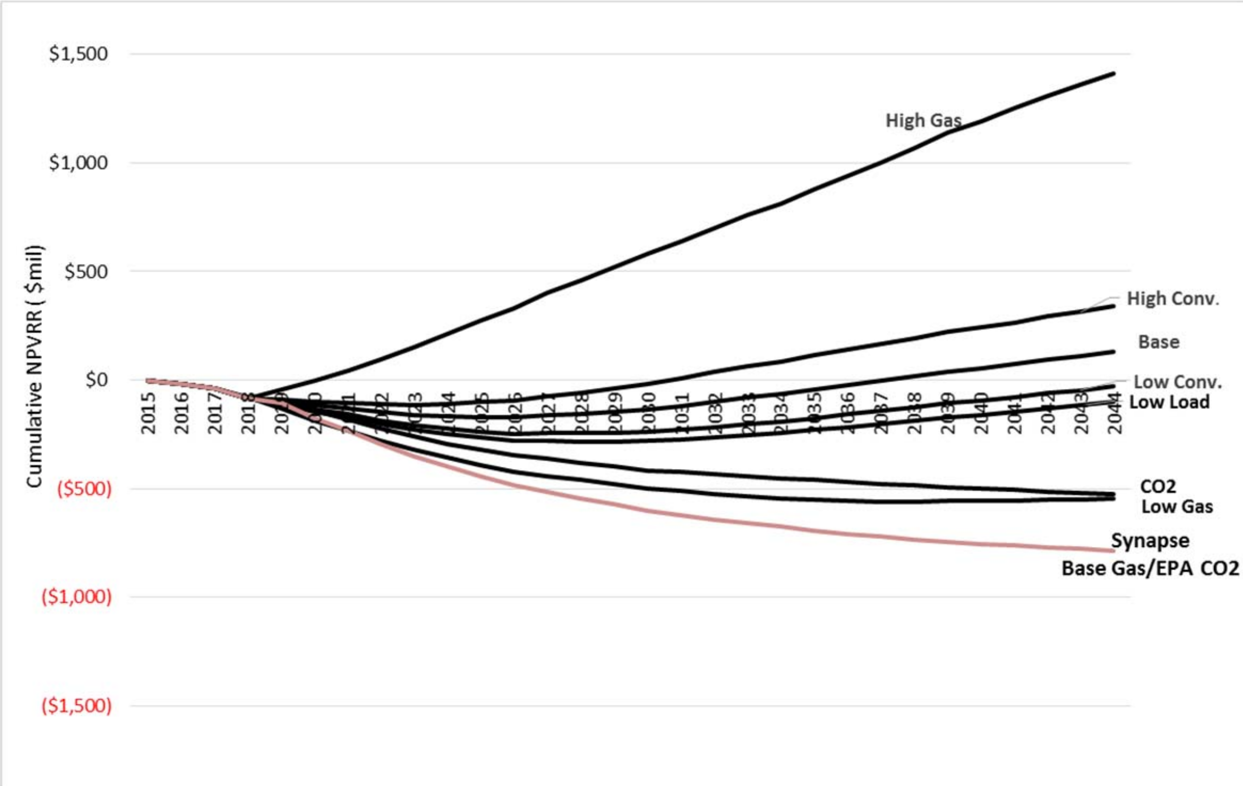

Figure 8: Cumulative Net Benefit of Benefit (Cost) of Retrofitting Sooner 1&2 with Synapse Base Gas/EPA CO_2 Scenario (NPVRR, $2014 mil)[45]

Table 6: Cumulative Net Benefit of Benefit (Cost) of Retrofitting Sooner 1&2 with Synapse Base Gas/EPA CO_2 Scenario[46]

Scenario	Benefit of Retrofit (NPVRR $2014, mil)	Retrofit Breakeven Year
Base	$133	2038
CO_2	-$525	None
High Conversion	$340	2031
Low Conversion	-$30	None
High Gas	$1,413	2021
Low Gas	-$548	None
Low Load	-$100	None
Synapse Base Gas/EPA CO_2	-$784	None

[45] Id.
[46] Id.

Q Did you conduct a sensitivity analysis to account for the risk that OG&E would need to install SCRs on the Sooner units?

A Yes. I ran a sensitivity assuming the addition on an SCR on Sooner units 1 and 2. This additional cost was applied to the Synapse scenario run in PCI Gentrader by Ms. Wilson.

Q What were the initial results of adding SCR costs to the Synapse scenario?

A The cost of retrofitting Sooner units 1 and 2 increases by an additional $490 million in every scenario.[47] The net cost of the retrofit is now over $350 million in the Company's Base scenario (compared to a net benefit of $133 million without the SCR), over $1 billion under the Company's CO_2 sensitivity and $1.3 billion in the Synapse EPA CO_2 scenario.

[47] Synapse also ran the Company's CO2 scenario with the addition of SCR variable operating costs. However, the results showed a minimal change in NPVRR based on variable costs alone (approximately $20 million or less than 0.1% of NPVRR difference). Therefore, in the interest of time, we did not run the increased variable costs due to the SCR in the results presented in Figure 9.

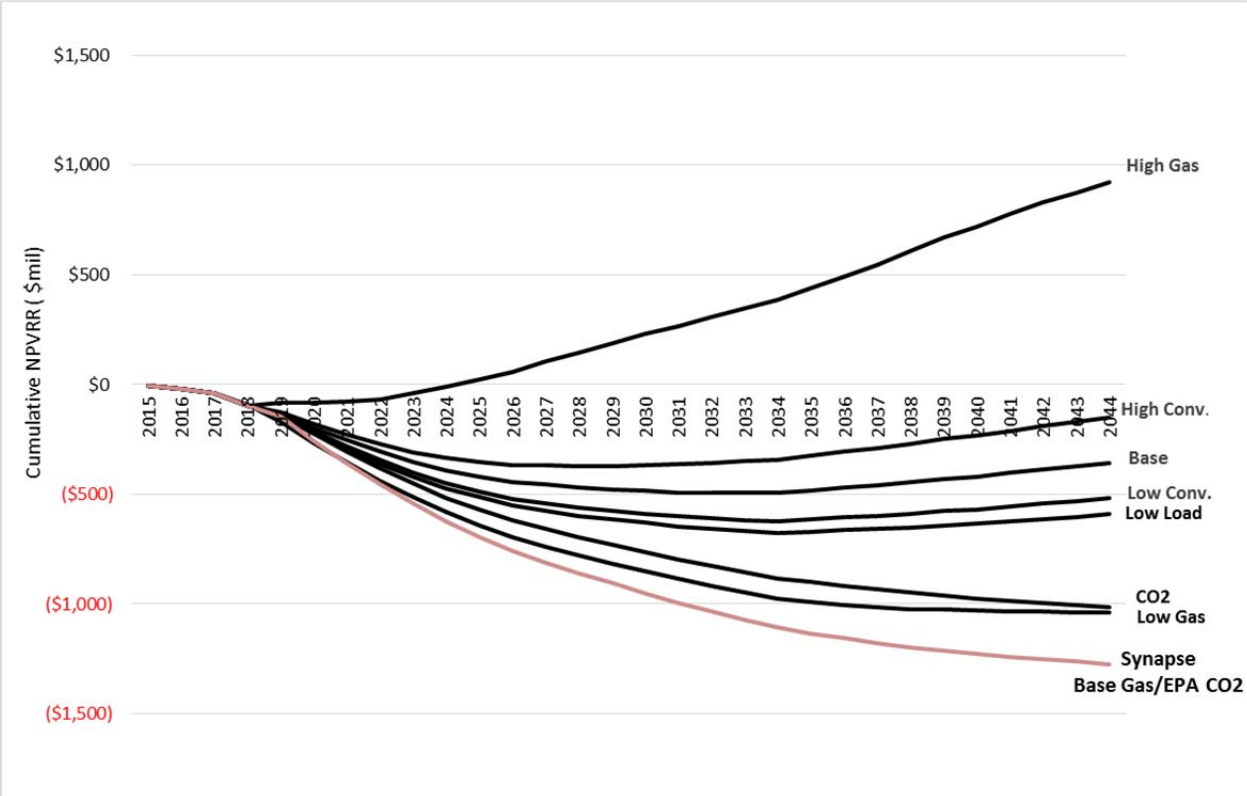

Figure 9: Cumulative Net Benefit (Cost) of Retrofitting Sooner 1&2 with SCR and Synapse Base Gas/EPA CO_2 Scenario (NPVRR, $2014 mil)[48]

Table 7: Cumulative Net Benefit (Cost) of Retrofitting Sooner 1&2 with SCR and Synapse Base Gas/EPA CO_2 Scenario[49]

	NPVRR without SCR ($2014, mil)		NPVRR with SCR ($2014, mil)	
Scenario	Benefit of Retrofit	Retrofit Breakeven Year	Benefit of Retrofit	Retrofit Breakeven Year
Base	$133	2038	-$357	None
CO_2	-$525	None	-$1,015	None
High Conversion	$340	2031	-$150	None
Low Conversion	-$30	None	-$520	None
High Gas	$1,413	2021	$923	2025
Low Gas	-$548	None	-$1,038	None
Low Load	-$100	None	-$590	None
Synapse Base Gas/ EPA CO_2	-$784	None	-$1,274	None

[48] Data Response 3-12_Att86. SCR costs are from Direct Testimony of Robert Burch, p. 7, Table 1.
[49] Id.

B. A PROPOSAL FOR ADDITIONAL WIND

Q Did the Company assume any additional wind in its 30-year analysis?

A No. The Company did not assume any new generating resources in its plan besides new natural gas plants.

Q What were the Company's reasons for not adding additional wind in this analysis?

A The Company mentions the low capacity credit for wind in SPP, and congestion issues.[50] Unfortunately, it assumes that neither one of these factors will change in the 30-year period. Witness Tripp addresses the Company's concerns regarding wind procurement and congestion issues.

Q Are there any recent developments that should encourage the Company to pursue additional wind?

A Yes. The production tax credit for wind was recently renewed by the U.S. House of Representatives to extend through 2014. There is the possibility of it being extended another year or two in the Senate.[51]

Q Have neighboring utilities pursued additional wind recently?

A Yes. Public Service of Oklahoma recently petitioned for approval from the OCC for 600 MW of new wind contracts. PSO cited that the projects were:

> …economically justified because according to the net revenue requirement analyses, using a fundamental forecast of avoided energy and capacity prices, the Balko, Goodwell and Seiling proposals were estimated to lower revenue requirement each year of the contracts through 2035…PSO estimates that the three projects will provide cost reductions of $89.5 million on a levelized annual basis under base case assumptions.[52]

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[50] Direct Testimony of Leon Howell, p. 20, lines 1-20.
[51] See http://www.bloomberg.com/news/2014-12-01/house-said-to-plan-vote-extending-lapsed-tax-breaks-through-2014.html
[52] Commission Order 621229, Cause No. PUD 201300188, p. 5.

In addition, GRDA (Grand River Dam Authority) recently signed 20-year PPA's with two wind farms in Oklahoma.[53]

Q Would a Wind PPA be economically attractive for the Company given its price scenarios?

A Yes. As presented in Figure 11, the costs of wind bids provided to the Company in response to its 2013 Request for Information [redacted] relative to all of the Company's energy price scenarios. Wind would thus provide [redacted] against fluctuations in the energy market.

[redacted]

[53] See http://m.newsok.com/grda-to-draw-power-from-two-new-wind-farms-in-oklahoma/article/3946984
[54] Data Response OIEC 5-8Att CONFIDENTIAL.

Q What are the key risks and benefits associated with a wind PPA?

A Committing to a long-term wind PPA carries the risk that energy market prices will become even lower than the cost of energy quoted in the PPA before it expires (see [redacted] above). [redacted] the energy cost of the wind remains [redacted] than all of the Company's energy price forecasts; therefore this risk is [redacted]. A wind PPA would also provide key benefits in the form of protection from risks of fuel price volatility and environmental risks. For example, there is no fuel cost associated with wind generation. The cost of these contracts are typically pre-determined and do not fluctuate each year, unlike the operating costs of fossil-generating units, which are subject to changing fuel prices and future environmental compliance costs.

Q Did the Company plan on the addition of new wind in any of their portfolios?

A No. The Company has 840 MW of existing wind capacity. However, in its 30-year forward-looking IRP and in this filing, it has assumed that no wind is added through a power purchase agreement or self-build. Given the low cost and high availability of wind in the region (as discussed by Witness Tripp), there is no legitimate reason to exclude additional wind as a future resource.

Q What additional wind resources did you model?

A Witness Tripp testifies that the Company could easily meet 20% of peak load with wind capacity, for a total of almost 1,200 MW. Therefore, I assumed this was a maximum level that could be met throughout the 30-year analysis period in 100 MW minimum blocks of wind (shown in Figure 11). In 2015, the Company could add 300 MW of wind and almost meet 20% of its peak load. Importantly, it would be possible to have more wind on the system; this represents simply what is possible under a 20% maximum.[55]

[55] See Direct Testimony of Jennifer Tripp.

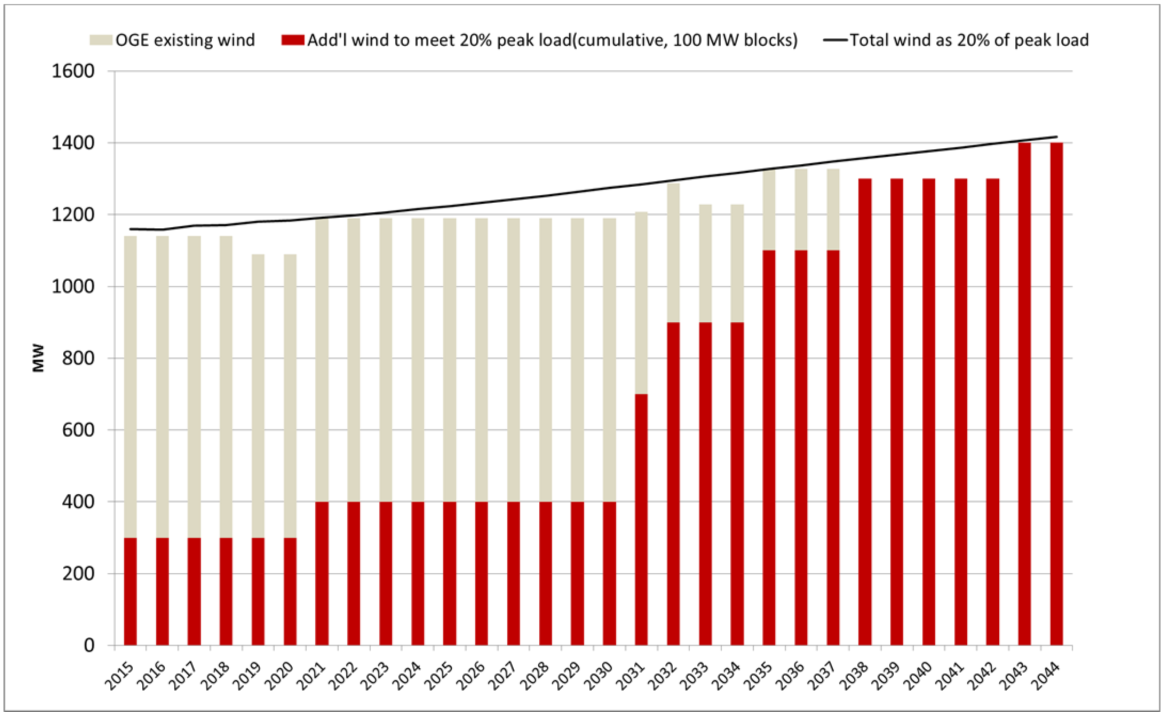

Figure 11: OG&E Wind Capacity: Existing and capacity proposed by Synapse (MW, nameplate)[56]

Q What were the initial results of additional wind on the NPVRR results?

A The addition of wind reduced the NPVRR in every scenario (shown in [redacted]). This [redacted] is due to the relative [redacted] of wind compared to market prices. Using the Company's NPVRR methodology, I multiplied the hourly output of wind[57] by the PROMOD hourly prices generated from the various market scenarios used by OG&E, as well as the Synapse EPA CO_2 price scenario. In almost all years, sensitivities, and scenarios, the additional wind generated [redacted]. The Low Gas scenario generated losses after 2032 but still resulted in an [redacted] over the 30-year period. Not surprisingly, the High Gas, CO_2, and Synapse EPA CO_2 and SCR scenarios generated the largest [redacted] since market prices for energy are [redacted] in those scenarios. Thus, wind is shown to be an [redacted] both higher gas and higher carbon costs.

[56] See, for example OIEC 1-11_Att03_2014_IRP_ProdCost_Convert_Base_CT_spread.
[57] The hourly output of the additional wind resources was generated by Witness Tripp based on NREL data for a typical wind pattern in Oklahoma with an annual capacity factor of 47%.

Q Did you assume the production tax credit for wind was available?

Yes. I assumed that the production tax credit was available for projects coming on-line in 2015 and 2016 but not afterwards. If OG&E were to add more wind in 2015/2016 or if the production tax credit is extended further, then the presented benefits of wind would increase.

[redacted]

Q Does the reduction in NPVRR change the cost of the Sooner retrofit relative to conversion to natural gas?

A No; using the methodology used by the Company, the addition of the same amount of wind to both the Scrub/Convert and the Convert portfolios would equally reduce their NPVRRs. Therefore, the relative difference in cost between the retrofitting or converting Sooner units 1 and 2 (shown in Table 7) would not change as a result of the addition of wind to OG&E's system, using the Company's methodology.

[58] Data Response 1-37_Att1 CONFIDENTIAL

Q How should your analysis inform the Company's decisions going forward?

A My analysis and the modeling conducted by Ms. Wilson show the critical risks associated with the Company's pursuit of the Scrub/Convert portfolio. By excluding a carbon price from its Base scenario, the Company did not sufficiently account for carbon cost risk. It also neglected to account for future environmental compliance costs outside of its current obligations. The Company's Convert portfolio provides a lower cost solution in most scenarios and sensitivities run by the Company and in all but one scenario (High Gas) in the likely event that an SCR is required on Sooner units 1 and 2. As I explained previously, the Company's High Gas scenario should be given little credence since it is higher than any of the sensitivities run by the EIA (see Figure 5).

The alternative modeling analysis also shows that wind provides a [redacted] in portfolio costs under any given scenario. The pursuit of additional wind should be an [redacted] the SPP market in the future and, unlike the Company's remaining coal fleet, would not be subject to environmental cost risks.

My analysis dies not correct flaws in the Company's underlying modeling structure problems including:

- The Company only evaluated fixed combinations of units which did not allow for unit-by-unit economic analysis.
- The Company did not evaluate other alternatives outside of retrofitting, converting or retiring and replacing with self-build natural gas plants.
- The Company chose a fixed set of new natural gas plants in order to maintain its capacity needs throughout the 30-year period rather than conduct capacity expansion modeling
- The Company assumed a small level of energy efficiency going forward.

I discuss these flaws in greater detail in the next section. I would encourage the Company to incorporate these points in its modeling methodology going forward.

V. ADDITIONAL FLAWS IN THE COMPANY'S MODELING STRUCTURE

A. THE FRAMEWORK FOR OG&E'S ANALYSIS IS FUNDAMENTALLY FLAWED.

Q How did OG&E evaluate its compliance alternatives?

A As discussed, OG&E evaluated five set compliance portfolios: 1) scrub the two Sooner units and convert Muskogee units 4 and 5 ("Scrub/Convert"), 2) scrub all four units ("Scrub"), 3) convert all four units ("Convert"), 4) scrub the Sooner units and replace the Muskogee units ("Scrub/Replace"), and 5) replace all four units ("Replace").

Q Is the way that OG&E structured its compliance alternatives sound?

A. No. Under OG&E's methodology of examining only pre-selected portfolios of units, decisions for retiring units and new builds are essentially fixed, rather than allowing them to be influenced by sensitivities in load growth and commodity prices. A more rigorous analysis would allow the economic viability of units or plants to fluctuate based on important variables, rather than holding them fixed. The Company's resource planning should allow regulators to review the economic viability of individual units. The Company's PROMOD model has the capability to evaluate decisions on this basis, but the Company neglected to do so. This would require modeling the entire fleet with changes to individual units (retrofit, conversion or retirement) and comparing the differences in fleet-wide costs with each unit-specific change.

Q How should companies address risks and uncertainties in electricity resource planning?

A Electricity generation involves very long-term investments, which will often produce energy--and impose costs on ratepayers--for decades. Over the projected lifetime of a new power plant or major retrofit, there is inescapable uncertainty about market conditions, prices, load growth, and the regulatory environment. To account for this uncertainty, responsible planning practices require the utility to evaluate any proposed major investment under a range of possible future scenarios, or sensitivities.

Q Do the market sensitivities used by OG&E allow for a reasonable evaluation of the risks and uncertainties facing OG&E's proposed investments?

A Not entirely. While the analysis includes sensitivities for some variables (gas prices, capital costs, and CO_2), it applies them only to pre-selected portfolios, rather than on a unit-by-unit basis. Moreover, OG&E runs each sensitivity in isolation of the others, rather than in combination. For instance, low load and low natural gas prices might occur simultaneously but OG&E does not analyze the combined impact of these sensitivities on NPVRR. There are several dimensions of uncertainty that the Company must consider in evaluating the proposed retrofit including carbon costs and additional environmental compliance costs.

Q Why should a company evaluate reasonable alternatives?

A Sound planning requires an honest and rigorous evaluation of a range of practical alternatives. The Company evaluated only two alternatives to retrofitting Sooner: 1) converting both Sooner units to natural gas, and 2) retiring and replacing both units with a new natural combined cycle (NGCC) unit.

Q Was the Company's decision not to evaluate other alternatives reasonable?

A No. The Company should have evaluated more alternatives to the self-build options of retrofitting, converting or replacing its own units. A more rigorous review of alternatives would allow the Company to meet its energy and capacity requirements through other sources such as low cost power purchase agreements ("PPAs"), renewable energy options including wind, solar, and residual biomass, demand side management options including energy efficiency and demand response, or purchasing existing generation facilities, if available.

The Company also assumes a fixed set of natural gas units are added throughout the 30-year analysis period to maintain the SPP capacity margin. As Dr. Fisher discusses in more depth, the Company should have conducted capacity expansion modeling in order to optimize its future builds, rather than assuming a fixed set of new natural gas plants in the future.

Q Do you think the Company was justified in not issuing a request for proposals to replace the Muskogee and Sooner units?

A No. It is axiomatic that if you do not ask a question, you are unlikely to find the answer. Yet when it came to determining what options were available to OG&E for replacing the Muskogee and Sooner plants, and at what price, the Company never asked the question. One way of asking would have been for OG&E to issue a request for proposal ("RFP") seeking proposals for the sale of various energy resources. Such an RFP process would have helped OG&E determine whether other companies were willing to sell generating assets or guaranteed energy or capacity from natural gas combined cycle plants, natural gas combustion turbine, wind, solar, hydroelectric, biogas, or other energy resources that are either existing or being developed could have been part of a lower-cost portfolio.

The Company received an unsolicited offer for an existing NGCC but rejected it because it "did not offer enough capacity to replace one of the Muskogee coal units."[59] However, the Company could have considered such a bid in combination with another resource if it is trying to replace capacity at Muskogee.

B. THE COMPANY FAILED TO ADEQUATELY EVALUATE ENERGY EFFICIENCY.

Q Why should OG&E consider energy efficiency and demand response as part of an alternative portfolio to replacing the units with a new gas plant?

A The Company's load forecast assumptions are critical since they determine how much capacity is needed to serve demand on the system at peak times. Simply put, a higher forecasted peak load will result in a more costly portfolio, since more build-out is needed. Demand-side management ("DSM") measures reduce peak load through Demand Response ("DR"), which is only called upon during peak hours, and Energy Efficiency ("EE"), which is spread among the hours of

[59] Data Response OER 5-3b.

the day. Thus, DR directly reduces peak load but has little effect on energy sales, while EE reduces sales and also reduces peak load if it happens to take effect during those hours.

Energy efficiency is frequently lowest cost resource compared to electricity generation.[60] Efficiency measures also lower peak demand, thus reducing the need to build more generating capacity in the future.

Q Did the Company forecast future energy efficiency and demand response in its planning?

A Yes, but unfortunately, the Company assumes that it will make only minimal investments in DSM in the future. As shown in Figure 13, taking the incremental EE each year divided by the previous year's load, OG&E forecasts between 0.2% and 0.5% in new peak reductions from EE each year until 2021, after which no new EE is added (and so the cumulative EE savings declines). Assuming no new EE investments after 2021 is unreasonable given the 30-year analysis period used in this filing. This also translates into a similar percentage of energy reductions each year.

[60] See Lazard's Levelized Cost of Energy, p. 4. Available here: http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

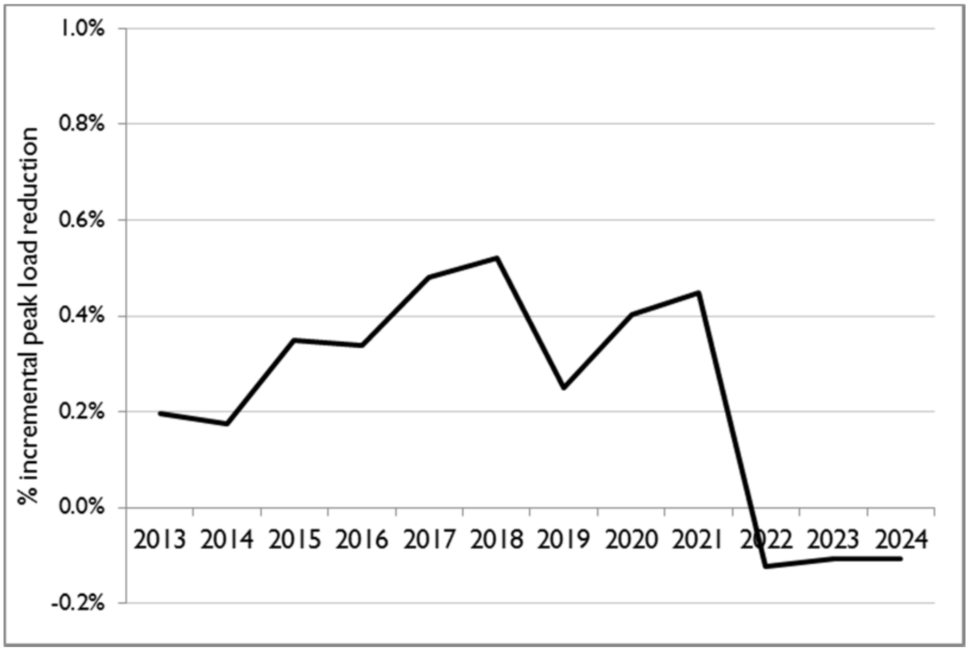

Figure 13: Annual incremental energy efficiency savings (% of previous year's peak load) projected by OG&E[61]

Q Do you think that OG&E adequately estimated DSM going forward?

A No. OG&E's projection likely understates OG&E's future DSM and deprives OG&E customers of significant savings. An expert report commissioned by Sierra Club as part of its comments to the Commission's proposed demand program rule changes, found that raising annual energy savings to 1.0% by 2016 and to 2.0% within 5 years thereafter is consistent with best practices in neighboring states, and would result in an estimated 1,931 in gigawatt-hours savings through 2019, displace the need for 425 MW of generating capacity, and avoid $1.69 billion in net resource costs.[62]

Figure 14 shows the impact of additional DSM reductions on capacity requirements relative to OG&E's capacity needs (existing and new) assumed in the IRP. Synapse assumed an alternative in which OG&E would reach 1%

[61] Exhibit LCH-1, p. 22.
[62] *See* Sierra Club Comments to Proposed Rule Changes to Electric Utility Rules 165:35 Subchapter 41, Demand Programs, Cause No. RM 201300012.

incremental peak load reduction by 2019 and persist at this level through 2024.[63] The cumulative effect of the accelerated installation of efficiency measures amounts to substantially lower capacity requirements—more than 500 MW reduction by 2024. Compared with the Company's planned capacity expansion ("CT Spread"), this alternative shows the extent to which additional EE reductions could reasonably obviate the need for some new builds associated with OG&E's proposed expansion—such as the planned 560 MW CC in 2020—and defer other investments. This modest EE goal would also lower energy requirements that would be purchased on the SPP market.

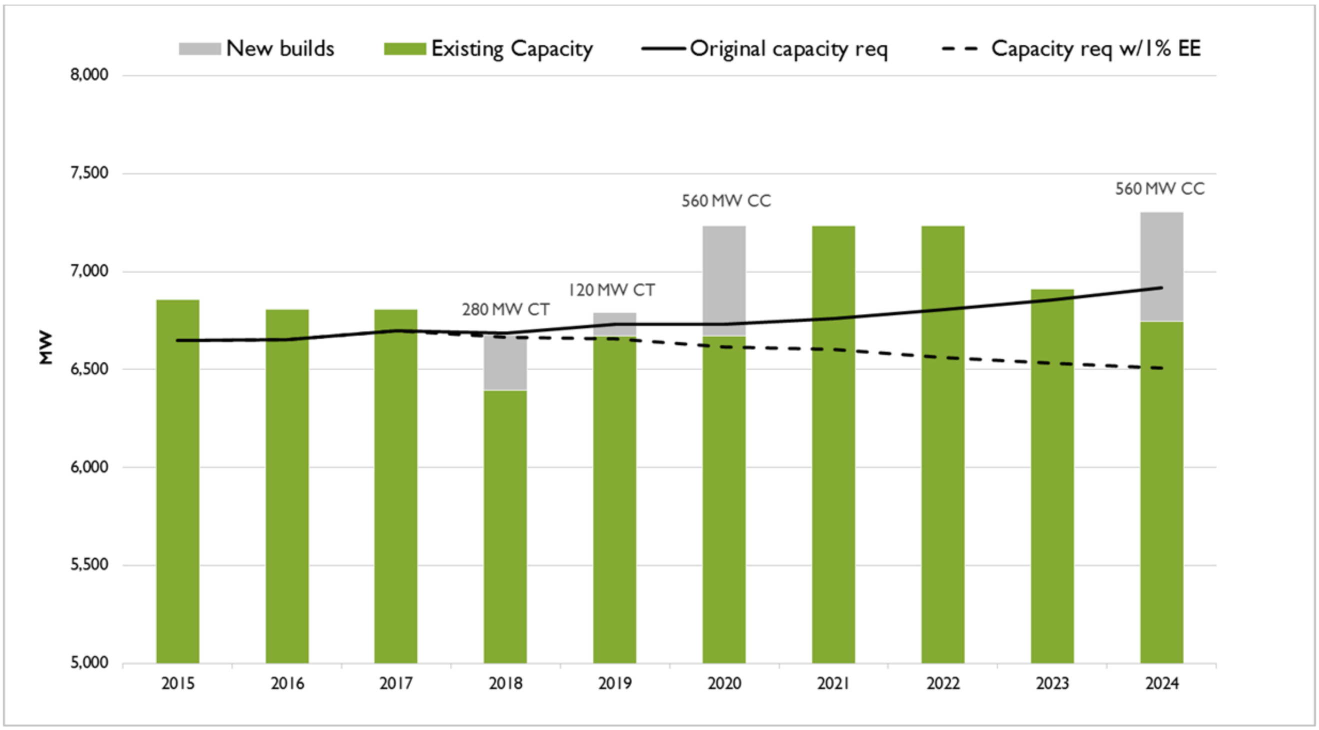

Figure 14: OG&E Capacity Requirements

[63] According to EPA, Oklahoma could achieve 10% cumulative EE savings by 2029 as part of efficiency building block for 111(d). See *Federal Register, Vol. 79, No. 117, June 18, 2014, p.34873.* Ramping up to 1% annual incremental savings by 2019—along with the Company's incremental EE in the earlier years--would achieve approximately 8% cumulative savings by 2024.

VI. FINDINGS AND RECOMMENDATIONS

Q What are your findings?

A The Company has not provided sufficient justification for the retrofit of Sooner units 1 and 2 given the following:

1. The Company's own analysis shows that retrofitting Sooner is more costly than converting it to natural gas, in most scenarios. In fact, it is only the least-cost option in year 24 of its 30-year analysis. In my alternative analysis, I show that converting Sooner to natural gas is less costly than retrofitting it in every scenario except for one (High Gas) and it is always the least-cost option in every year of the analysis period.

2. The Company did not adequately assess carbon cost risk despite the recent release of the proposed EPA Clean Power Plan.

3. The Company neglected to address other future environmental risks and costs associated with Sooner, mainly the high likelihood that additional NOx controls will be required.

4. The Company neglected to consider additional wind in its system despite its attractive costs and availability in the region.

5. The Company's modeling methodology is fundamentally flawed since the Company did not conduct capacity expansion modeling, review other alternatives or include incremental energy efficiency after 2021, despite modeling a 30-year analysis period.

Q What are your recommendations for the Commission?

A I recommend that the Commission deny the Company's application for approval to retrofit Sooner units 1 and 2. The Company's own modeling shows that the retrofit option is barely economical compared to the Convert option in its Base scenario—a scenario that subjects its ratepayers to significant risk as it includes no compliance costs for carbon or other environmental regulations—and it is not the least cost alternative in the majority of sensitivities and scenarios the

Company considered. Second, when an appropriate range of sensitivities are considered, converting the Sooner units to natural gas—part of the Company's "Convert" portfolio—is likely less expensive and less risky over the long-term than retrofitting the units. Finally, the pursuit of additional wind generation would [redacted] the customers' costs across all scenarios and sensitivities due to its [redacted] relative to the SPP energy market prices.

Q **Does this conclude your testimony?**

A It does.

Tyler Comings, Senior Associate

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tcomings@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate,* July 2014 – present, *Associate*, July 2011 – July 2014.

Conducts research on energy system planning and coal plant economics, and performs economic modeling and analysis in support of a wide range of projects. Performs economic impact and benefit-cost analyses, statistical modeling, and research on environmental issues. Recent work includes developing economic impacts of energy efficiency programs in Vermont and a scenario of clean energy investments for the U.S.

Ideas42, Boston, MA. *Senior Associate*, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, and worked with top researchers in behavioral economics. Managed implementation and data analysis for a study of mitigation of default for borrowers that were at-risk of delinquency. Performed case studies for World Bank on financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. *Research Analyst*, *Economic Consultant*, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Performed statistical modeling, including results on the timing of effects of highway construction on economic growth in Appalachia. Developed a unique Web-tool for the National Academy of Sciences on linkages between economic development and transportation, and presented findings to state government officials around the country. Created economic development strategies and improvements to company's economic development software tool.

Harmon Law Offices, LLC., Newton, MA. *Billing Coordinator, Accounting Liaison*, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs for cases at the firm.

Massachusetts Department of Public Health, Boston, MA. *Data Analyst* (contract), 2002.

Designed statistical programs using SAS based on data taken from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics and other healthcare facilities for statewide assessment.

EDUCATION

Tufts University, Medford, MA
Master of Arts in Economics, 2007

Boston University, Boston, MA
Bachelor of Arts in Mathematics and Economics, 2002. *Cum Laude*, Dean's Scholar.

ADDITIONAL SKILLS

Software: MS Office, STATA, SPSS, SAS, REMI, IMPLAN, Mathematica
Programming: C++
Languages: Conversant in French

PUBLICATIONS

Takahashi, K. 2014. *Maximizing Public Benefit through Energy Efficiency Investments.* Synapse Energy Economics for Sierra Club.

Comings, T., S. Fields, K. Takahashi, G. Keith. 2014. *Employment Effects of Clean Energy Investments in Montana.* Synapse Energy Economics for Montana Environmental Information Center and Sierra Club.

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Hornby, R., D. White, T. Vitolo, T. Comings, K. Takahashi. 2012. *Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky*. Synapse Energy Economics for Mountain Association for Community Economic Development and the Kentucky Sustainable Energy Alliance.

Hausman, E., T. Comings, G. Keith. 2012. *Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland*. Synapse Energy Economics for Sierra Club.

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Economic Development Research Group and Navigant Consulting. 2008. *Economic Potential of an Advanced Biofuels Sector in Massachusetts*. Prepared for the Massachusetts Office of Energy and Environmental Affairs.

Economic Development Research Group. 2006. *Environmental Impacts of Massachusetts Turnpike and Central Artery/Tunnel Projects*. Prepared for the Massachusetts Turnpike Authority.

TESTIMONY

Maryland Public Service Commission (Case No. 9361): Direct testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities. On behalf of the Maryland Office of the People's Counsel. December 8, 2014.

State of New Jersey Board of Public Utilities (Docket No. EM14060581): Direct testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities. On behalf of the New Jersey Division of Rate Counsel. November 14, 2014.

District of Columbia Public Service Commission (Formal Case No. 1119): Direct testimony evaluating the economic impact analysis of the proposed Exelon-Pepco merger. On behalf of the District of Columbia Government. November 3, 2014.

Kentucky Public Service Commission (Case No. 2013-00259): Direct and supplemental testimony regarding East Kentucky Power Cooperative's Application for Cooper Station Retrofit and Environmental Surcharge Cost Recovery. On behalf of Sonia McElroy and Sierra Club. November 27, 2013 and December 27, 2013.

Indiana Utility Regulatory Commission (Cause No. 44339): Direct testimony in the Matter of Indianapolis Power & Light Company's Application for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Gas Turbine Generation Facility. On behalf of Citizens Action Coalition of Indiana. August 22, 2013.

Resume dated December 2014

Oklahoma Industrial Energy Consumers
Data Request OIEC-3
Cause No. PUD 201400229

3-12 Reference OG&E's response to OIEC 1-12 and Chart 3 on page 18 of Mr. Howell's direct testimony, provide the forecasted total annual nominal revenue requirements and 30-year cumulative NPV of revenue requirements for the selected Scrub/Convert portfolio and each alternative plan evaluated by OG&E for each year of the 2014 IRP analysis, for the base case and each sensitivity case evaluated, in an electronic format.

Response*: Please see **OIEC 1-11_Att** (files 1 through 35) and **OIEC 3-12_Att** (files 1 through 70) for the total annual nominal production cost and 30-year cumulative NPV of production cost for each of the Regional Haze Compliance Alternatives and expansion plan option in each scenario and sensitivity as described in OG&E's 2014 IRP Update. Please see **OIEC 3-12_Att** (Files 71 through 85) for the forecasted 30-year cumulative.

NPV of revenue requirements along with the total annual nominal return on rate base and expenses for each of the Regional Haze Compliance Alternatives and expansion plan option in each scenario and sensitivity as described in OG&E's 2014 IRP Update.

Response provided by: Leon Howell
Response provided on: September 29, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Energy Results
Data Request OER-5
Cause No. PUD 201400229

5-3 In the 2014 IRP, on P. 48 OG&E states ". . . It should also be noted that acquisition of an existing 500 MW combined-cycle plant could be an alternative to the conversion of a Muskogee unit. OG&E has acquired two existing combined-cycle plants over the past decade (McClain and Redbud) and continues to monitor CC plants across the SPP region. However, it should also be noted that our analysis indicates that the acquisition cost of this alternative would have to be very aggressive in order to compete with the "Convert" alternative, less than $250/kW for a new highly efficient plant. Older CC plants with higher heat rates would make sense only at lower acquisition costs. Thus, it appears that it isn't a viable alternative as OG&E believes no combined cycle plants are available at the acquisition cost necessary make this alternative economical."

a. Please provide detailed calculations to explain how the threshold value of $250/kW was derived. What is the sensitivity of the threshold value to the assumed costs of the "Convert" option?

b. Please provide any studies, offers, or investigations conducted within the last three years that indicate the value that current owners of CC's in the region ascribe to their capacity. If offers were received, were subsequent analyses conducted on the viability of the offers? If yes, please provide detailed analyses or studies comparing the overnight costs, fuel, and other relevant factors used to develop a levelized production cost estimate comparing the combined cycle plant purchase with the converted Muskogee or Sooner coal plants.

Response*:

a. Please see **OCC 2-2_Att6_RORB_Expenses_Purchase Plant 250** for the detailed calculation of how the threshold value of $250/kW was derived. The threshold value is derived by solving for a Purchase Price that, when combined with the other estimated costs of operation, produces the same 30 year net present value of customer costs as the conversion.

b. Please see **Cogen 1-5_Att_Confidential** for an unsolicited offer OG&E received in the last three years that indicates capacity value in the SPP. OG&E compared the unsolicited offer to the $250/kW value calculated for the convert alternative and determined the convert alternative to be the best alternative. The unsolicited offer did not offer enough capacity to replace one of the Muskogee coal units.

Response provided by: Leon Howell
Response provided on: December 5, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Sierra Club
Data Request Sierra Club-1
Cause No. PUD 201400229

1-16 State whether OG&E has prepared or caused to be prepared any study of the costs to bring of Sooner Units 1 and 2 or Muskogee Units 4, 5 and 6 (either individually or jointly), into compliance with the EPA's proposed Clean Water Act Section 316(b) rule.

- **a. If so:**
  - **i. Identify the costs that were identified**
  - **ii. State whether such costs were factored into the NPV analysis for each unit**
    - **1. If so, explain how**
    - **2. If not, explain why not**
  - **iii. Produce all such studies**

Response*: Yes, Sargent & Lundy prepared two studies for OG&E that evaluates options for Sooner Units 1 and 2 or Muskogee Units 4, 5 and 6, to meet the EPA's proposed Clean Water Act Section 316(b) rule.

a.i. Costs are identified in the studies

a.ii. No, the costs were not included in the environmental compliance plan.

aa.ii.1. N/A

aa.ii.2. There continues to be uncertainty about compliance requirements. Costs are relatively low and would not impact OG&E's decision to add scrubbers at Sooner and convert Muskogee 4 and 5 to natural gas.

a.iii. Please see **Sierra 1-16_Att1_Confidential**.

Response provided by: Leon Howell
Response provided on: October 10, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Sierra Club
Data Request Sierra Club-1
Cause No. PUD 201400229

1-16 Revised **State whether OG&E has prepared or caused to be prepared any study of the costs to bring of Sooner Units 1 and 2 or Muskogee Units 4, 5 and 6 (either individually or jointly), into compliance with the EPA's proposed Clean Water Act Section 316(b) rule.**

a. If so:

iv. Identify the costs that were identified

v. State whether such costs were factored into the NPV analysis for each unit

1. If so, explain how

2. If not, explain why not

vi. Produce all such studies

Response*: Yes, Sargent & Lundy prepared two studies for OG&E that evaluates options for Sooner Units 1 and 2 or Muskogee Units 4, 5 and 6, to meet the EPA's 2004 proposed Clean Water Act Section 316(b) rule. OG&E has not done such a study for the 2011 proposed rule which was finalized in May 2014.

a.i. Costs are identified in the studies

a.ii . No, the costs were not included in the environmental compliance plan.

aa.ii.1. N/A

aa.ii.2. There continues to be uncertainty about compliance requirements. Costs are relatively low and would not impact OG&E's decision to add scrubbers at Sooner and convert Muskogee 4 and 5 to natural gas.

a.iii. Please see **Sierra 1-16_Att_Confidential** which was prepared for the previous rule which is no longer in effect.

Response provided by: Usha Turner
Response provided on: October 13, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Sierra Club
Data Request Sierra Club-1
Cause No. PUD 201400229

1-17 State whether OG&E has prepared or caused to be prepared any study of the costs to bring of Sooner Units 1 and 2 or Muskogee Units 4, 5 and 6 (either individually or jointly), into compliance with the regulatory options being considered in EPA's proposed Coal Combustion Residuals rule.

- **a. If so:**
  - **i. Identify the costs that were identified**
  - **ii. State whether such costs were factored into the NPV analysis for each unit**
    - **1. If so, explain how**
    - **2. If not, explain why not**
  - **iii. Produce all such studies**
- **b. If not, explain why not**

Response*: OG&E has not prepared any studies of the potential cost of compliance with the proposed. This is a proposed rule which could change significantly before finalization and as such, the final requirements and how they affect OG&E's units and what those requirements would actually cost, is unknown at this time. OG&E also does not dispose of any coal combustion byproducts on site

Response provided by: Usha Turner
Response provided on: October 9, 2014
Contact & Phone No: Sheri Richard 405-553-3747

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Sierra Club
Data Request Sierra Club-1
Cause No. PUD 201400229

1-18 State whether OG&E has prepared or caused to be prepared any study of the costs to bring of Sooner Units 1 and 2 or Muskogee Units 4, 5 and 6 (either individually or jointly), into compliance with the potential changes to National Ambient Air Quality Standards ("NAAQS").

- **a. If so:**
  - **i. Identify the costs that were identified**
  - **ii. State whether such costs were factored into the NPV analysis for each unit**
    1. **If so, explain how**
    2. **If not, explain why not**
  - **iii. Produce all such studies**
- **b. If not, explain why not**

Response*: No. There are proposed rules for some of the NAAQS, which are pending finalization and in some cases have been pending for 4 years. These rules could change significantly before finalization and as such, the final requirements and how they affect OG&E's units and what those requirements would actually cost, is unknown at this time.

Response provided by:	Usha Turner
Response provided on:	October 10, 2014
Contact & Phone No:	Sheri Richard 405-553-3747

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Oklahoma Corporation Commission
Data Request PUDKC-3
Cause No. PUD 201400229

3-2 On October 8, 2014, the U.S. EPA submitted a proposed ozone rule to OMB. EPA is under court order to revise or retain the current national ambient air quality standard (NAAQS) for ozone by December 1, 2014. EPA is widely expected to reduce the 8-hour standard from 75 ppb to between 60 and 70 ppb. Has OG&E evaluated the potential impact on its generation units if the ozone NAAQS were lowered from 75 parts per billion to 60 parts per billion? If so, please provide any studies, reports, or other analysis conducted. If not, please explain why not.

Response*: OG&E has not evaluated the impact of a future, potential revised ozone standard. Oklahoma is in attainment with the ozone standard that is currently in effect. Any impacts to OG&E of any future revision will not be know until a standard is finalized by EPA, a SIP is developed by the State and approved by EPA. However, the Environmental Plan calls for reductions in NOx that positions the company and state better toward compliance with future ozone rules.

Response provided by: Usha Turner
Response provided on: November 10, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-1
Cause No. PUD 201400229

1-4 At IRP pages 17-18, section h, OG&E discusses two complaints or sets of complaints against it. OG&E concludes that if it does not prevail, it could be forced to install additional pollution control equipment.

a. Please explain what additional equipment OG&E could be required to install beyond what it is already planning to install in its preferred compliance plan. Please also discuss whether there is a potential that OG&E would be required to install some equipment earlier than OG&E plans to do.

b. If OG&E does not prevail against either or both of these complaints, would that change the relative ranking by net present value of customer costs of the scenarios run in the IRP? If so, how? Please explain.

Response*:

a. OG&E continues to believe that it has acted in compliance with the Federal Clean Air Act, and OG&E will continue to vigorously defend against the claims that have been asserted. If OG&E does not prevail, the plaintiffs could seek to require the installation of selective catalytic reduction to control NOx emissions at all five coal-fired units, and they could seek to require the installation of an additional SO2 scrubber at Muskogee Unit 6. In light of the current pace of the litigation against OG&E and the amount of time that similar litigation has taken, it seems unlikely that these measures could be required before the beginning of 2019.

b. OG&E has not modeled a possible outcome of the New Source Review. Therefore it is not known how it would impact the relative ranking by net present value of customer costs of the emission alternatives considered in the IRP.

Response provided by:	Leon Howell/Robert Burch
Response provided on:	October 23, 2014
Contact & Phone No:	Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.