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Oklahoma Gas & Electric Co.

Integrated Resource Plan

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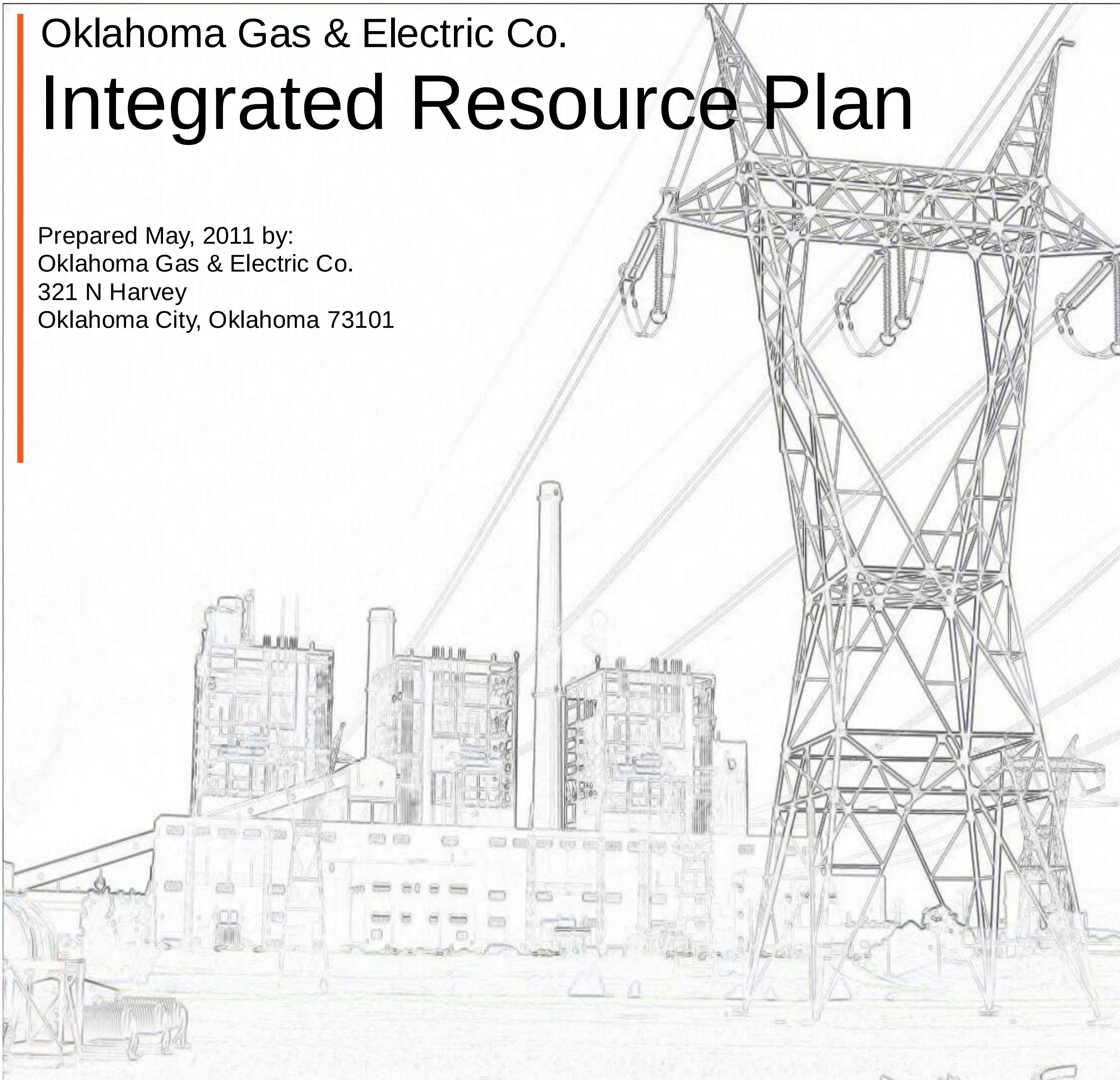

EXECUTIVE SUMMARY

INTRODUCTION

OG&E submits this interim Integrated Resource Plan ("IRP") pursuant to the joint stipulation and settlement agreement for Oklahoma Corporation Commission Cause No. PUD 201000037.

DEMAND RESPONSE AND ENERGY EFFICIENCY

OG&E last updated its IRP in January 2010. This update builds on the conclusions in the January submittal that actions such as the timely termination of wholesale contracts, encouraging energy efficiency and demand response programs and other programs enabled by the smart grid offer benefits to customers. These actions are expected to reduce peak demand and, when combined with actions identified in the 2009 IRP, are projected to defer the need for new fossil fuel generation beyond the year 2020.

Actions to Reduce Peak Demand (MW)

		2012	2013	2014	2015	2016
Demand	Retail Peak Forecast	5,823	5,898	5,989	6,073	6,123
	Wholesale Peak Forecast	281	274	239	243	-
	Total Peak Forecast	6,104	6,172	6,228	6,317	6,123
Energy Efficiency and Demand Response	Energy Efficiency	38	38	39	39	39
	Distribution Automation	8	17	26	37	48
	Residential DR	71	143	216	218	219
	Commercial & Industrial DR	-	-	23	47	70
	Load Curtailment	105	120	135	150	151
	Total Peak Reduction	222	318	439	491	527
	System Peak Demand	5,882	5,853	5,789	5,826	5,596

RENEWABLE ENERGY

With the completion of the Crossroads Wind Farm, OG&E will have added 611 MW since 2008. OG&E has made no decision whether to issue a RFP for additional wind resources but will continue to monitor the market for renewable projects that benefit customers while contributing to the State's renewable energy goal.

TRANSMISSION

The 2010 SPP Transmission Expansion Plan ("STEP") has identified projects that will be constructed over the next five years for reliability and economic purposes, including new generation additions such as wind. OG&E plans to participate in this expansion by constructing some of the projects that have been approved for construction by the SPP Board of Directors as listed in Schedule J.

INTEGRATED MARKETPLACE

The SPP is still developing the rules for an Integrated Marketplace concept to provide efficiencies and transparency to serving customers' energy needs throughout the SPP. This concept is expected to impact the way OG&E's generation units operate.

MECHANICAL INTEGRITY

The Mechanical Integrity ("MI") Plan is the formalization, development and standardization of plant maintenance and reliability procedures, in an effort to mitigate safety risks and improve reliability of the Company's generation assets.

EMISSION CONTROL OPTIONS

On March 7, 2011, the EPA issued a proposed rule in which the Agency rejected the Oklahoma State Implementation Plan ("SIP") for SO_2 BART determinations and instead proposed a Federal Implementation Plan ("FIP") with a SO_2 emission limit of 0.06 lb/MMBTU. The FIP provides that this proposed emission limit can be achieved by either the installation of four scrubbers on the four affected coal-fired units or conversion of those four units to natural gas-fired units. The public comment period extends to May 23, 2011 and a final rule will occur sometime after that. OG&E is preparing comments to the proposed rule and evaluating the appropriate course of action.

CONCLUSION

OG&E's 2020 goal has allowed for flexibility in decision making for future expansions, wind development, and emission control options. OG&E will continue to explore demand side opportunities, monitor renewable resource markets, develop MI Plan and prepare for the SPP Integrated Marketplace. As emission control requirements become clearer and technologies develop, OG&E will match technologies with the requirements to provide the best value to customers.

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I. INTRODUCTION

OG&E submits this interim Integrated Resource Plan ("IRP") pursuant to the joint stipulation and settlement agreement in Oklahoma Corporation Commission Cause No. PUD 201000037.

This IRP presents a snapshot of challenges and opportunities for OG&E as of April 2011. OG&E's resource planning is the foundation for management decisions regarding the appropriate methods and manner in which to meet the reliable future needs of its retail customers. In reality, OG&E is continually evaluating resource alternatives in response to constantly evolving conditions and opportunities.

Section II presents the IRP objective and process. Section III offers an overview of OG&E, the demand and energy forecast, and modeling assumptions and inputs used in the analysis. Section IV explains the analysis methodology and results. Section V concludes the report with a tabular summary of each section as described in Oklahoma Corporation Commission rule OAC 165:35-37-4(c) and outlined below:

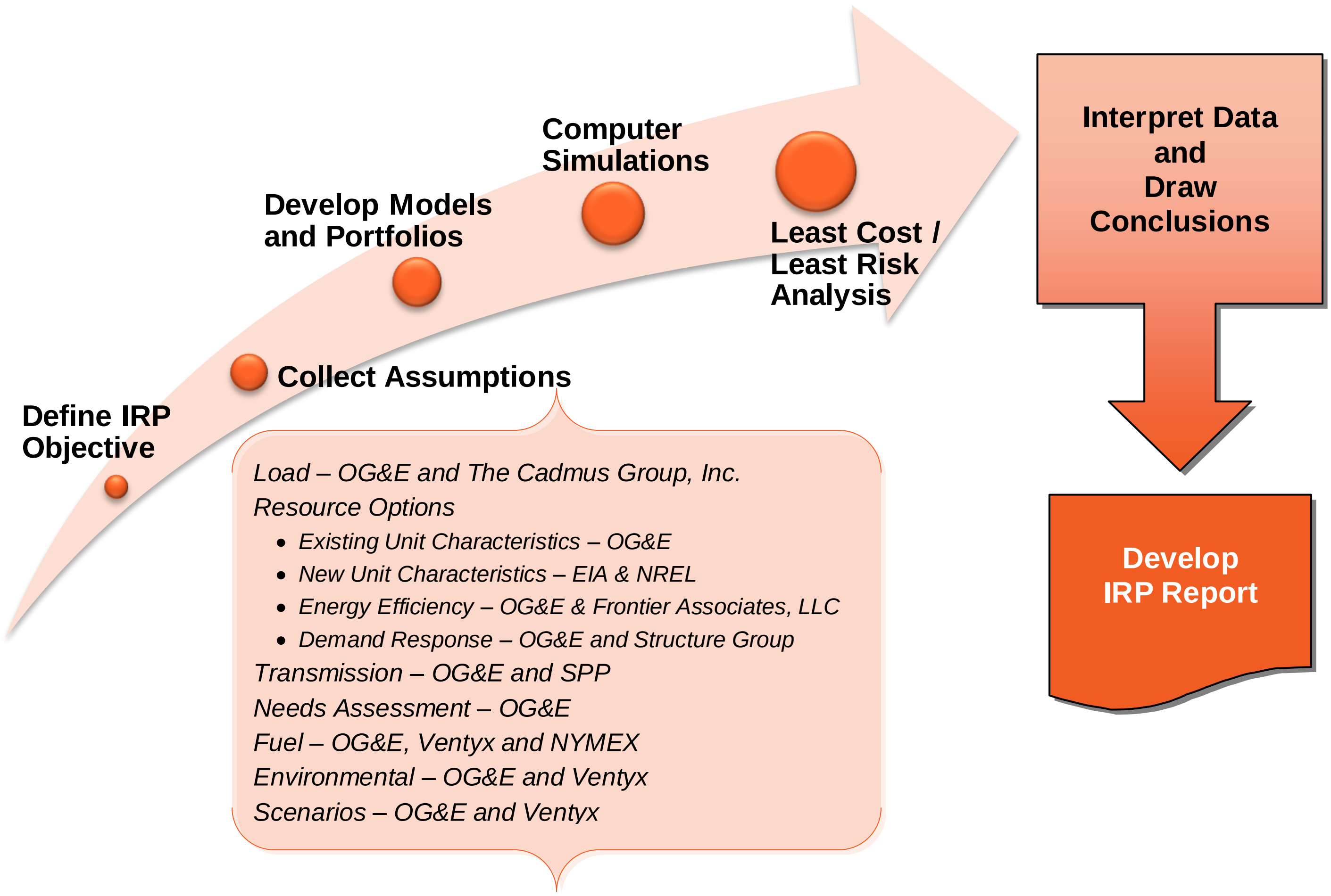
A. Electric demand and energy forecast
B. Forecast of capacity and energy contributions from existing and committed supply- and demand-side resources
C. Description of transmission capabilities and needs covering the forecast period
D. Assessment of the need for additional resources
E. Description of the supply, demand-side and transmission options available to the utility to address the identified needs
F. Fuel procurement plan, purchased power procurement plan, and risk management plan
G. Action plan identifying the near-term (i.e., across the first five (5) years) actions
H. Proposed RFP(s) documentation, and evaluation
I. Technical appendix for the data, assumptions and descriptions of models
J. Description and analysis of the adequacy of its existing transmission system
K. Assessment of the need for additional resources to meet reliability, cost and price, environmental or other criteria
L. An analysis of the utility's proposed resource plan

In addition, this submittal contains several appendices that provide supporting materials, including studies and reports that have been prepared by OG&E, by vendors retained by OG&E, and stakeholders.

II. IRP OBJECTIVE AND PROCESS

The objective of the OG&E's IRP process is to analyze alternatives to meet customers' demand and energy needs over a 30 year period given forward looking assumptions based upon today's circumstances. OG&E continually monitors markets and inputs and updates elements of the IRP. When material changes in assumptions occur, OG&E will formally update its IRP submittal, as well. To accomplish the IRP objective, OG&E utilizes a seven step process as outlined in Figure 1.

Figure 1: Integrated Resource Planning Seven Step Process



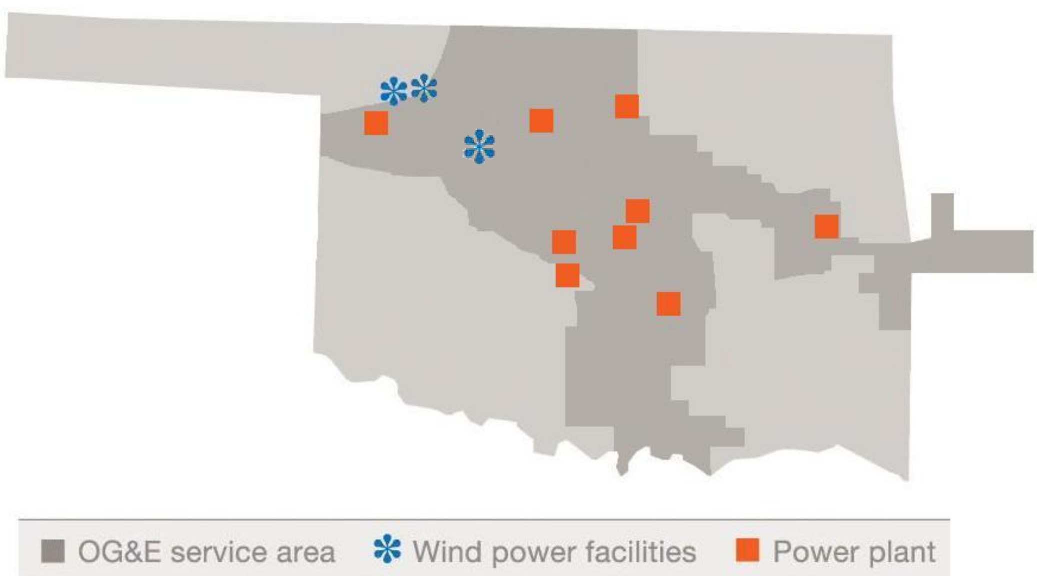
III. ASSUMPTIONS AND INPUTS

This section includes a description of major assumptions and inputs to the models used to develop this IRP.

A. Description of OG&E Service Territory

OG&E serves more than 779,000 retail customers in Oklahoma and western Arkansas, as well as several wholesale customers throughout the region. The service territory covers approximately 30,000 square miles, includes 269 communities and surrounding areas, and has a population of approximately 2 million. OG&E serves Oklahoma City, which is the largest city in Oklahoma, as well as Ft. Smith, Arkansas. Of the 269 communities served by OG&E, 243 are in Oklahoma, and 26 are in Arkansas. OG&E's retail service area is shown in Figure 2.

Figure 2: OG&E Service Area



OG&E's system control area peak demand for 2010, as reported by the OG&E system dispatcher, was 6,626 MW on August 4. The control area peak demand includes retail, wholesale and other provider's demands. OG&E's load responsibility peak demand for 2010 was 6,171 MW on August 4.

B. Electric Demand and Energy Forecast

OG&E retained the services of The Cadmus Group, Inc. to assist OG&E's Research and Analysis department prepare the September 2010 load forecast that is presented in Appendix A – OG&E 2010 Load Forecast. Their report describes the data inputs, assumption methodologies, and models developed jointly with OG&E's Research and Analysis department with input from OG&E's Interdepartmental Forecasting Task Force.

The 2010 retail sales forecast utilized the revenue class based econometric modeling framework that has been in place for over a decade. The 2010 load responsibility peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility, used since the 2000 forecast.

The load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of electricity prices for price-sensitive customer classes. The final energy and demand forecast includes Federal Energy Regulatory Commission ("FERC") jurisdictional wholesale contracts as post-modeling adjustments.

1. Load Forecast Methodology

Load forecasting includes projections of energy sales and peak demand requirements.

a) Energy Sales Forecast Methodology

The 2010 retail energy forecast is based on retail sector-level econometric models representing OG&E's Oklahoma and Arkansas service territories. Historical and forecast economic variables (drivers) are provided by the Center for Applied Economic Research at Oklahoma State University ("OSU").

In past forecasts, Moody's Economy.com provided economic drivers that were used to predict energy sales in OG&E's Arkansas service territory. In 2010, OG&E made the decision to purchase forecasts of economic drivers for both Oklahoma and Arkansas from OSU. The move from Moody's Economy.com to OSU was made because consolidating the sources for economic drivers would simplify the load forecasting process. By using a single source for economic drivers OG&E has eliminated the need to adjust the Arkansas drivers to follow the same assumptions as the Oklahoma drivers.

b) Peak Demand Forecast Methodology

The 2010 load responsibility forecast relies on an hourly econometric model specification first used for the 2000 forecast and reflects the following:

1. Impact of different weekdays on hourly system load.
2. Impact of different summer months on hourly system load.
3. Influence of heat buildup during heat waves.
4. Impact of the combined effects of humidity and warm temperatures.
5. Non-linearity in the load and temperature relationships at very high temperatures.

As has been the case for the past several years, weather-adjusted retail energy sales are the main driver for the peak model.

2. Forecast of Key Assumptions

The following is an excerpt from the September 2010 load forecast.

a) Economic Outlook

Over the last decade the Oklahoma economy has outperformed the nation during recessions due to robust growth in the energy sector. Prudent lending practices and limited direct erosion of the consumer balance sheet allowed Oklahoma to enter the most recent recession later than the nation. The effects of the recession in Arkansas have been dampened due to the limited influence of low energy prices and employers delaying plans to outsource manufacturing operations. Both states have fared better than the nation, and are poised to recover when energy prices increase and the rest of the country returns to positive economic conditions.

1) Energy Sector

The OSU forecast drivers anticipate the price of oil hovering around $70/barrel, and natural gas around $5 per MMBTU in 2010. These prices are close to the threshold where energy switches from providing a net boost to restricting growth in the state economy. While the price of oil is beginning to increase, it has been around $70 a barrel for most of the year, and the price of natural gas has been below $4.50 per MMBTU. The Energy Information Administration ("EIA") forecast[1] suggests that natural gas will remain below $5 per MMBTU through the end of 2010, with oil climbing to an average of $80 a barrel in the fourth quarter of 2010.

After experiencing considerable decline in activity in 2009, the energy sector in Oklahoma is seeing a considerable recovery in 2010. Since hitting a low of $1.84 per MMBTU on September 4th, 2009, the price of natural gas has rebounded to nearly $4.50 per MMBTU in 2010. This has allowed for the continued development of conventional oil and natural gas wells in the Arkoma Basin in western Oklahoma along with the Woodford Shale in southeast Oklahoma and the Fayetteville Shale in central Arkansas.

The recovery of the energy sector in Oklahoma will play a vital role in the overall growth of the Oklahoma economy. As energy prices increase so will revenue collections for Oklahoma. The gross production tax on natural gas yielded $24 million in July of 2010, which is $1.9 million or 8.4 percent above the prior year. Oklahoma has made efforts to diversify its economy, but the energy sector is still the foundation.

2) Retail Electric Prices

The retail electric prices used in the forecast include the revised cost of operations along with riders for various other projects. There are riders for OG&E's Smart Grid and the OU Spirit wind farm included in the price forecast. Additionally, the price forecast includes the cost of new transmission. Finally in 2010 there was a fuel clause adjustment refund paid to customers. The refund offset most of the rate increase in

[1] The Energy Information Administration: Short-term Energy Outlook, http://www.eia.doe.gov/emeu/steo/pub/contents.html

2010, so customers experienced a negligible increase in price during 2010. However, the conclusion of the fuel clause adjustment refund at the end of 2010 will make the effective price increase from 2010 to 2011 approximately 17 percent. A price increase of this magnitude is responsible for the relatively low growth rate in 2011.

3) Price Elasticity of Demand

The own-price elasticity of demand for the residential sector in Oklahoma has been restricted to -0.1 from 2010 to 2012 and -0.2 from 2013 to 2020. The unrestricted estimate of own-price elasticity of demand for the residential sector in Oklahoma is -0.24. This unrestricted estimate is relatively more elastic than the 2009 estimate of -0.05, but it remains highly inelastic when compared to other goods. The main cause of the disparity between the 2009 and 2010 estimates is the use of an all-good price index instead of an energy specific price index to adjust prices for inflation. The all-good price index more accurately reflects the effects of inflation on a consumer's budget and their energy consumption decisions. Own-price elasticity of demand was restricted due to the impacts it would have on the forecast when combined with unprecedented price increases in the short-run. The restrictions limit the effect of prices in the near-term and allow for an increased long-term response to changes in the retail price of electricity in the Oklahoma residential sector. The elasticity estimates in other sectors were relatively unchanged from the 2009 forecast, so there were no other restrictions implemented.

b) Weather Input

Peak demand and energy sales are highly sensitive to year-to-year weather variations. Both can appear to decline even with positive economic growth when a hot year is followed by an unusually cool year. Conversely, if a hot year follows a cool year, energy sales and peak demand can increase even though there may be little or no economic growth.

Weather uncertainty is represented through a Monte Carlo modeling approach where the more than 20 years of actual weather are systematically input into the energy and peak models to produce a possible outcome distribution.

OG&E's weather-year Monte Carlo approach runs weather years 1989 to 2009 through weather-sensitive energy models, along with the peak demand model, to develop a probability distribution of possible outcomes.

3. Energy Sales Forecast

The 2010 energy sales forecast adds FERC wholesale sales contracts and line losses to retail econometric model forecast projections. The forecast is based on normal weather in both Oklahoma and Arkansas. In the fourth quarter of 2010, OG&E extended the wholesale contract with Arkansas Valley Electric Cooperative Corporation (AVECC) through June of 2015. The energy associated with this contract was added to the 2010 energy sales forecast and is summarized in Table 1

Table 1: OG&E 2010 Energy Sales Forecast

GWH	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wholesale	1,616	1,537	1,274	1,274	-	-	-	-	-	-
Retail	27,501	27,865	28,364	28,828	29,224	29,682	30,013	30,501	30,950	31,369
Total	29,118	29,401	29,638	30,102	29,224	29,682	30,013	30,501	30,950	31,369
Retail Growth	1.9%	1.3%	1.8%	1.6%	1.4%	1.6%	1.1%	1.6%	1.5%	1.4%

4. Peak Demand Forecast

Table 2 shows the final load responsibility forecast, adjusted for wholesale loads[2] and line losses. The forecast is based on normal weather conditions.

Table 2: OG&E 2010 Peak Demand Forecast

MW	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wholesale	281	274	239	243	-	-	-	-	-	-
Retail	5,823	5,898	5,989	6,073	6,123	6,228	6,278	6,371	6,456	6,528
Total	6,104	6,172	6,228	6,317	6,123	6,228	6,278	6,371	6,456	6,528
Retail Growth	1.5%	1.3%	1.5%	1.4%	0.8%	1.7%	0.8%	1.5%	1.3%	1.1%

C. Resource Options

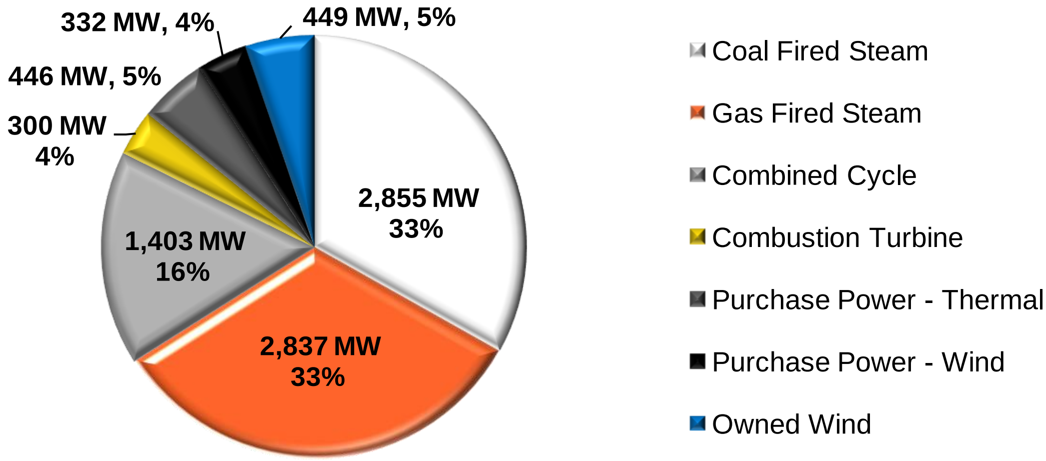
OG&E plans for future generation needs by first understanding the resource options available to the Company. The following sections identify the existing supply side resources, supply side alternatives and the ongoing demand side resources.

1. Existing Supply Resources

OG&E's generation resources include coal fired units, gas fired steam units, gas fired combined cycle ("CC") units, gas fired combustion turbine ("CT") units, and wind facilities. OG&E generates approximately 60% of its electric energy from low-sulfur Wyoming coal and 37% from natural gas and 3% wind. OG&E purchases 320 MW from the qualifying facility AES plant at Shady Point that burns coal, 120 MW from the natural gas fired combined cycle PowerSmith plant and 6 MW of hydro generation from Southwest Power Administration ("SPA"). The hydro generation is transferred from wholesale customers to OG&E as part of the wholesale customers' purchase power agreements. OG&E currently has under contract three wind energy power agreements: Sooner Wind at 50 MW, Keenan at 151.8 MW, and Taloga at 130 MW. For peak planning purposes, these three wind farms contribute approximately 9 MW. Figure 3 depicts the composition of OG&E's generation resources by nameplate capacity.

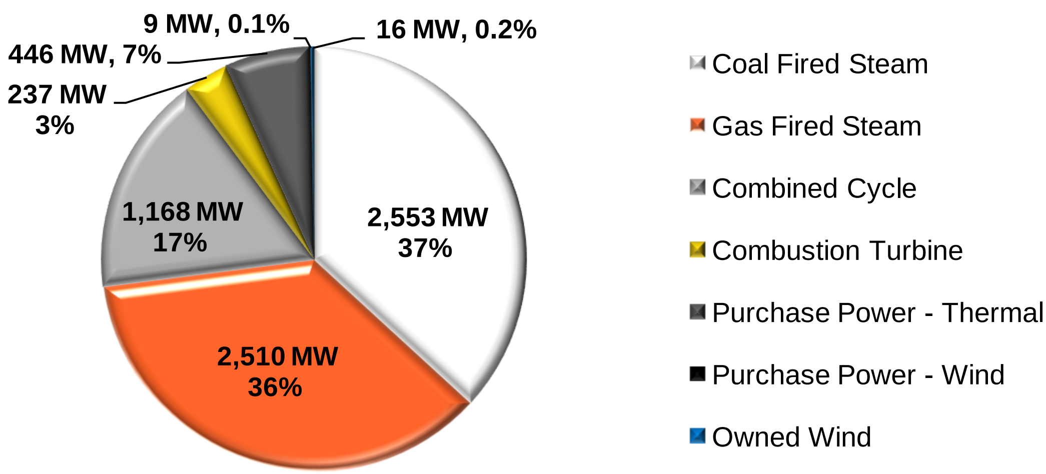
[2] This forecast reflects the termination of the AVECC contract in 2015 and the remaining contracts by 2014.

Figure 3: Generator Nameplate Capacity



OG&E's net dependable rated capability for each unit is determined from unit testing during the summer months in accordance with SPP Criteria 12. The latest Capability Report was published on December 31, 2010 and reported a net dependable rated capability of 6,432 MW from OG&E's ten power plants. The complete 2010 capability report can be found in Appendix B. Figure 4 depicts the composition of OG&E's peak planning capacity.

Figure 4: Peak Planning Capacity



OG&E's current portfolio of electric generating facilities is presented in Table 3. With the exception of the McClain and Redbud plants, OG&E fully owns all of its plants. OG&E is the operator of all of its plants, including McClain and Redbud. For this IRP, all thermal units are expected to operate beyond the 30-year study.

Table 3: OG&E Planned Generation Resources

UNIT TYPE (PLANNING CAPACITY)	UNIT NAME	FIRST YEAR IN SERVICE	PEAK PLANNING CAPACITY (MW)	AVERAGE HEAT RATE (BTU/KWH)
Coal Fired Steam (2,553 MW)	Muskogee 4	1977	505	10,935
	Muskogee 5	1978	500	10,932
	Muskogee 6	1984	502	10,948
	Sooner 1	1979	522	10,223
	Sooner 2	1980	524	10,232
Gas Fired Steam (2,510 MW)	Horseshoe Lake 6	1958	159	11,253
	Horseshoe Lake 8	1968	381	12,210
	Mustang 1	1950	50	12,740
	Mustang 2	1951	51	12,724
	Mustang 3	1955	113	11,328
	Mustang 4	1959	253	11,207
	Seminole 1	1971	500	13,699
	Seminole 2	1973	500	12,166
	Seminole 3	1973	503	11,981
Combined Cycle (1,168 MW)	Horseshoe Lake 7	1963	227	11,283
	McClain*	2001	352	7,480
	Redbud*	2004	589	7,187
Combustion Turbine (237 MW)	Enid 1GT	1965	14	20,767
	Enid 2GT	1965	14	20,767
	Enid 3GT	1965	14	20,767
	Enid 4GT	1965	14	20,767
	Horseshoe Lake 9	2000	45	10,381
	Horseshoe Lake 10	2000	45	10,381
	Seminole 1GT	1971	17	N/A
	Mustang 5A	1971	32	14,647
	Mustang 5B	1971	32	14,647
	Woodward	1963	10	19,082
Purchase Power - Thermal (446 MW)	AES Shady Point	1991	320	11,817
	PowerSmith	1998	120	8,583
	SPA Hydro	N/A	6	N/A
Purchase Power - Wind (9 MW)	FPL Wind	2003	2	N/A
	Keenan	2010	4	N/A
	Taloga	2011	3	N/A
Owned Wind (16 MW)	Centennial	2007	7	N/A
	OU Spirit	2009	3	N/A
	Crossroads	2012	6	N/A
Total Net Dependability Capability			6,939	

** Represents OG&E owned interest*

The Mechanical Integrity ("MI") Plan is the formalization, development and standardization of plant maintenance and reliability procedures, in an effort to mitigate safety risks and improve reliability of the Company's generation assets. Within the plan there is a program on each piece of equipment or system to be inspected. This includes an assessment of condition and failure risk of the equipment and the formulation of either repair or replacement plans based on the assessment.

2. Supply Side Resource Alternatives

The new supply side resources considered are those used by the EIA in developing their Annual Energy Outlook 2010[3]. A summary is shown in Table 4.

Table 4: New Supply Side Resources in 2010$

TYPE	TECHNOLOGY	NOMINAL CAPACITY (MW)	HEAT RATE (BTU/ KWH)	OVERNIGHT CAPITAL COST ($/KW)	FIXED O&M COST ($/KW)	VARIABLE O&M COST ($/MWH)
Coal	Single Unit Advanced PC	650	8,800	3,167	35.97	4.25
	Dual Unit Advanced PC	1,300	8,800	2,844	29.67	4.25
	Single Unit Advanced PC w/ CCS	650	12,000	5,099	76.62	9.05
	Dual Unit Advanced PC w/ CCS	1,300	12,000	4,579	63.21	9.05
	Single Unit IGCC	600	8,700	3,565	59.23	6.87
	Dual Unit IGCC	1,200	8,700	3,221	48.90	6.87
	Single Unit IGCC with CCS	520	10,700	5,348	69.30	8.04
Natural Gas	Conventional NGCC	540	7,050	978	14.39	3.43
	Advanced NGCC	400	6,430	1,003	14.62	3.11
	Advanced NGCC with CCS	340	7,525	2,060	30.25	6.45
	Conventional CT	85	10,850	974	6.98	14.70
	Advanced CT	210	9,750	665	6.70	9.87
	Fuel Cells	10	9,500	6,835	350.00	-
Uranium	Dual Unit Nuclear	2,236	N/A	5,335	88.75	2.04
Biomass	Biomass CC	20	12,350	7,894	338.79	16.64
	Biomass BFB	50	13,500	3,860	100.50	5.00
Wind	Onshore Wind	100	N/A	2,438	28.07	-
	Offshore Wind	400	N/A	5,975	53.33	-
Solar	Solar Thermal	100	N/A	4,692	64.00	-
	Small Photovoltaic	7	N/A	6,050	26.04	-
	Large Photovoltaic	150	N/A	4,755	16.70	-
Geo-thermal	Geothermal - Dual Flash	50	N/A	5,578	84.27	9.64
	Geothermal - Binary	50	N/A	4,141	84.27	9.64
MSW	Municipal Solid Waste	50	18,000	8,232	373.76	8.33
Hydro	Hydro-electric	500	N/A	3,076	13.44	-
	Pumped Storage	250	N/A	5,595	13.03	-

Assumptions for emission control technologies considered in this IRP were obtained from Sargent & Lundy and Burns & McDonnell and are provided in Table 5.

[3] http://www.eia.doe.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

Table 5: Emission Control Technologies in 2010$

TECHNOLOGY	UNIT TYPE	CAPITAL COST ($M)	FIXED O&M COST ($M)	VARIABLE O&M COST ($/MWH)
Scrubber	Coal	308.8	7.3	2.52
Low NO_x Burners	Coal	14.3	0.9	-
Low NO_x Burners	Gas	9.6	0.6	-
Mercury Control- Activated Carbon Injection	Coal	2.1	0.3	0.57

3. Demand Side Resources

Demand Side Management ("DSM") is composed of two product areas that are focused on the customer end of the value chain. These areas are Energy Efficiency and Demand Response.

a) Energy Efficiency

Energy Efficiency ("EE") programs are designed to encourage customers to permanently improve how they use energy by using it differently and more efficiently. Inducements are provided through programs and services designed to educate customers to change energy usage behaviors and to more efficiently use energy. Several of OG&E's programs have endured over the last few decades and their effects are captured in the econometric load forecast models and therefore in OG&E's annual load forecast. These continuing programs include:

- Positive Energy Home – promotion of DOE Energy Star® Homes program requirements targeting low-income new construction projects
- Geothermal Home – promotion of DOE Energy Star® Homes program requirements targeting both the residential and commercial markets and focuses on both new and retrofit appliances
- Heat Pumps – promotion of high efficiency heating and cooling options encouraging the use of total electric HVAC units
- Rate Tamer® – an energy information service targeting larger commercial and industrial customers to provide on-line access to their business' energy consumption patterns via the internet
- Power Factor Correction – informs customer of power quality correction needs and options to help customers become more efficient and reduce OG&E generation needs

OG&E has recently introduced further comprehensive programs in effort to promote energy efficiency opportunities for all classes of customers. Since these programs are relatively new, the effects have not yet been realized in OG&E's annual load forecast.

1) Oklahoma Energy Efficiency Programs

In November 2007, OG&E contracted with Frontier Associates LLC to perform a comprehensive two-part potential study for its Oklahoma jurisdiction to identify potential energy efficiency and demand programs for implementation. The OG&E management team evaluated the Frontier Potential study programs and chose to implement eight programs based upon customer benefit, market potential and budget criteria, as well as the creation of an optimum portfolio to meet the goal of no new fossil fuel generation until 2020. The following eight programs are described in Cause No. PUD 200900200:

- Low Income Weatherization – home thermal efficiency services
- Fixed Income Weatherization – home thermal efficiency services
- Residential Thermal Efficiency – home thermal efficiency services including evaluation of HVAC equipment and duct work sealing
- Positive Energy: New Home Construction (“PE-NHC”) – promotion of energy efficient homes practices for construction of new homes
- Geothermal Heating, Cooling and Water Heating – offers incentives for installation of geothermal heat pumps in new or existing homes
- Commercial Lighting – promotion of the replacement of traditional fluorescent lighting with more efficient florescent lighting
- Commercial/Industrial Standard Offer Program (“SOP”) – offers financial incentives for the installation of a wide range of measures to reduce peak demand and/or save energy
- Education – offering of Custom Energy Report for customers and promotion of LivingWise® school education program

The Oklahoma programs are designed to produce annual demand and energy savings as shown in Table 6.

Table 6: Oklahoma EE Peak Demand and Energy Reduction

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand (MW)	36.6	36.6	36.6	34.6	32.7	30.7	30.7	30.1	27.6	25.2
Energy (MWh)	144,435	144,435	144,435	142,518	140,269	138,020	137,688	134,973	117,948	100,918

2) Arkansas Energy Efficiency Programs

The energy efficiency programs in Arkansas continue as a result of the work started through the Quick Start program as described in Docket No. 07-075-TF. These five programs are as follows:

- Weatherization – home thermal efficiency services
- LivingWise® – school educational program
- Custom Energy Report – self-administered energy survey for residential customers to understand their energy usage
- Commercial Lighting – education and incentives for replacing T-12 lamps in commercial and industrial lighting systems
- Motor Replacement – educates and offers incentives for replacing inefficient motors with high efficiency motors
- Education – provides information about energy efficiency and conservation

The Arkansas programs realize an annual demand and energy savings as shown in Table 7.

Table 7: Arkansas Energy Efficiency Peak Demand and Energy Reduction

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand (MW)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.0	0.8
Energy (MWh)	4,738	4,738	4,738	4,738	4,738	4,738	4,738	4,431	3,307	2,759

3) OG&E Energy Efficiency Forecast

The combined forecasted peak demand reduction and energy savings from the Oklahoma and Arkansas Energy Efficiency programs are found in Table 8.

Table 8: Total System Energy Efficiency Peak Demand and Energy Reduction

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand (MW)	38.1	38.1	38.1	36.2	34.2	32.2	32.2	31.5	28.7	26.0
Energy (MWh)	149,173	149,173	149,173	147,256	145,007	142,758	142,426	139,404	121,255	103,677

4) Additional Energy Efficiency Efforts

The current energy efficiency forecasts are based off of the 2009 plan to invest during the years 2010, 2011, and 2012. The remainder of the forecast shows how those efforts perform for the useful life of the measures implemented. OG&E continues to investigate future opportunities to expand the energy efficiency efforts such as geothermal heating. At the time of analysis for this IRP, an expansion of the geothermal program is estimated to reduce peak demand by 27 MW in ten years and save up to approximately 111,000 MWh. These projections are provided in Table 9. OG&E plans to file a new comprehensive 3 year Demand Program offering during June 2012. It is anticipated that some of the existing programs will remain and new measures will be introduced utilizing technology to continue and expand the results of the present portfolio.

Table 9: Geothermal Program Expansion Peak Demand and Energy Reduction

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand (MW)	0.2	0.4	1.2	2.7	4.9	8.1	11.9	16.2	21.1	27.0
Energy (MWh)	853	1,693	5,134	10,860	20,276	33,096	48,358	66,117	87,855	110,737

b) Demand Response Programs

Traditional demand response ("DR") programs have been designed to encourage customers to reduce their load during peak loading periods. Event driven programs are initiated by OG&E in response to varying external stimuli while price response programs are tariffs with predefined, recurring pricing. Since events are different from year to year, they are not included in the Annual Load Forecast but existing price response programs are included. Existing price response programs include:

- Real Time Pricing [Day-Ahead Pricing ("DAP")] – hourly prices are provided for the next day to allow customers the ability to shift their energy usage.
- Time-of-Use – seasonally and time-differentiated programs that communicate varying prices to customers signaling them to shift their energy use habits

In Cause No. PUD 201000029, the Oklahoma Corporation Commission approved OG&E's plan to deploy Smart Grid technologies throughout the Oklahoma service territory. The Distribution Automation Integrated Voltage and VAR control program allows reactive and voltage control elements on the circuit to be operated in a coordinated fashion to reduce the voltage profile or reactive power requirements along the feeder. This ability reduces on peak demand by 75 MW in within 10 years.

Other Smart Grid technologies included price response tools such as a Home Area Network ("HAN") system that provides customers with near real time information on their energy consumption, cost to date, current price, and assumed cost. The purpose is to allow communication to in home devices; primarily Programmable Communicating Thermostats ("PCT") or In Home Displays ("IHD") which provides information such as price signals, historic usage as compared to other customers, or usage month to date. Over the next ten years, OG&E is planning for 20% of the residential customers to adopt the in home devices, each reducing their energy consumption during OG&E system peak hours by an average of 1.3 kW. Likewise, commercial and industrial customers will be able to take advantage of more price response programs with an estimated peak demand reduction of 75 MW over the next 10 years.

In Cause No. PUD 200800398, OG&E restructured the event based programs to offer the Load Reduction Rider. This pricing schedule replaced previous event based tariffs while lowering the customers' annual on-peak period maximum demand requirement from 500 kW to 200 kW and above. More customers are eligible, however they needed to subscribe to the new rate and declare their load curtailment levels. As a result, the 2010 subscription dropped to approximately 89MW. OG&E continues to educate customers about the new tariff and expects the curtailment capabilities to return to the same relative level as before the tariff change. Table 10 shows the forecasts for these programs.

Table 10: Demand Response Assumption

(MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Distribution Automation	8	17	26	37	48	60	75	75	75	75
Residential DR	71	143	216	218	219	221	223	225	227	228
Commercial & Industrial DR	-	-	23	47	70	71	72	72	73	73
Load Curtailment	105	120	135	150	151	154	155	157	159	161
Total Reduction	184	280	400	452	488	506	525	529	534	537

D. Transmission

This section describes the OG&E's transmission resources, SPP transmission resources and any transmission upgrades related to OG&E generation expansion options. Summary of network upgrades from the 2010 SPP Transmission Expansion Plan is also discussed.

1. Transmission Resources

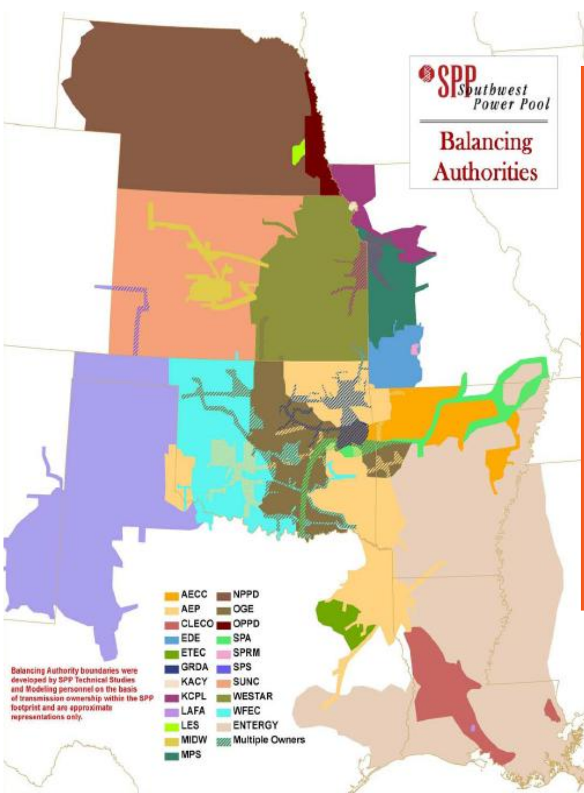
OG&E operates approximately 4,500 miles of transmission lines, 69 kV through 500 kV, throughout its service territory. Table 11 provides details of OG&E's transmission system line mileage at various voltages. These electric transmission lines move large amounts of power at high voltages from power plants. To increase reliability OG&E's transmission system is directly interconnected to seven other utilities' transmission systems at over 50 interconnection points. Indirectly OG&E is connected to the entire eastern interconnection through the SPP regional transmission organization.

Table 11: OG&E Transmission Lines

VOLTAGE	500KV	345KV	161KV	138KV	69KV	TOTAL
MILES	47	911	205	1,864	1,465	4,492

The SPP footprint covers 370,000 square miles and its 56 members serve over 5 million customers. It covers all of Kansas and Oklahoma and parts of seven other states: Arkansas, Louisiana, Mississippi, Missouri, New Mexico, Nebraska, and Texas. A representation of the balancing authorities[4] is provided in Figure 5.

Figure 5: SPP Balancing Authorities



The SPP footprint is comprised of 29 balancing authorities, which are operated by investor-owned utilities, cooperatives, and municipal and state agencies. A balancing authority is responsible for managing the supply and demand for electricity within its borders to assure reliability

[4] http://www.spp.org/publications/SPP_Footprints.pdf

2. Transmission Needs for Generation Expansion Options

Supply side resource options may require transmission investments. OG&E has identified proxy power plant sites and estimated the transmission expansion costs for each site. The sites shown in Table 12 were chosen for analysis purposes only and no determination has been made on future specific locations.

Table 12: Proxy Sites for Future Generation Resources

SITE DESCRIPTION	RESOURCE TYPE	COUNTY
North Central OK Area	Wind	Kay, Oklahoma
South Central OK Area	Wind	Murray, Oklahoma
Seminole Power Plant	NG CT	Seminole, Oklahoma
Sooner Power Plant	NG CC	Noble, Oklahoma

a) Wind

OG&E performed studies to estimate the transmission improvements necessary for delivery of wind generation. Two proxy sites were used for new wind generation. The first proxy site was interconnected on the Sooner to Rose Hill 345 kV transmission line in Kay County, Oklahoma. The second proxy site was interconnected at the Arbuckle Substation located in Murray County, Oklahoma. Both sites are in the service territory of OG&E. Contingency Analysis was performed to determine if any overloads were present due to the connection of the new wind generation. Power flow analysis identified two network constraints. These network constraints can be relieved by the conversion of the Prices Falls substation which is planned for pre-summer of 2012 and is already budgeted. Therefore there is no upgrade costs associated with the network constraints identified.

b) Seminole

Power flow analysis has indicated that connecting a new unit, up to 1,000 MW, at Seminole will require transmission upgrades to correct overloads in the OG&E and AEP control areas. The associated construction cost for a new unit at Seminole is estimated to be $9 million. There may be additional stability cost that could be determined in the SPP Study Process

c) Sooner

Power flow analysis has indicated that connecting a new 500 MW unit at Sooner will require transmission upgrades to correct overloads in the OG&E control area. The associated transmission construction cost for a new 500 MW unit at Sooner is estimated to be $7 million. Power flow analysis has indicated that connecting a new 1,000 MW unit at Sooner will require transmission upgrades to correct overloads in the OG&E and Entergy control areas. The associated transmission construction cost for a new 1,000 MW unit at Sooner is estimated to be $32 million.

3. SPP Transmission Expansion

In compliance with FERC Order 890 for transmission planning, the SPP does annual expansion planning for the entire SPP footprint. Therefore OG&E provides input to the SPP planning process, but is not ultimately responsible for the planning of the OG&E system.

The main objective of SPP's ten-year regional reliability assessment is to create a reliable long-range transmission expansion plan for the SPP footprint. The assessment identifies problems for normal conditions (no contingency) and single contingency scenarios using NERC Reliability Standards, SPP Criteria, and local planning criteria. It also coordinates appropriate mitigation plans to meet the SPP's regional reliability needs.

The 2010 SPP Transmission Expansion Plan[5] ("STEP") summarizes transmission planning efforts including regional reliability, local reliability, Generation Interconnection, long-term tariff studies due to transmission service requests, Balanced Portfolio, and Priority Projects[6]. Also identified are regional reliability projects in the 2011-2021 timeframe that do not need immediate action and will be considered in future plans. Table 13 offers a cost summary. Major transmission projects are illustrated in Figure 6.

Table 13: SPP STEP Projects Cost Summary

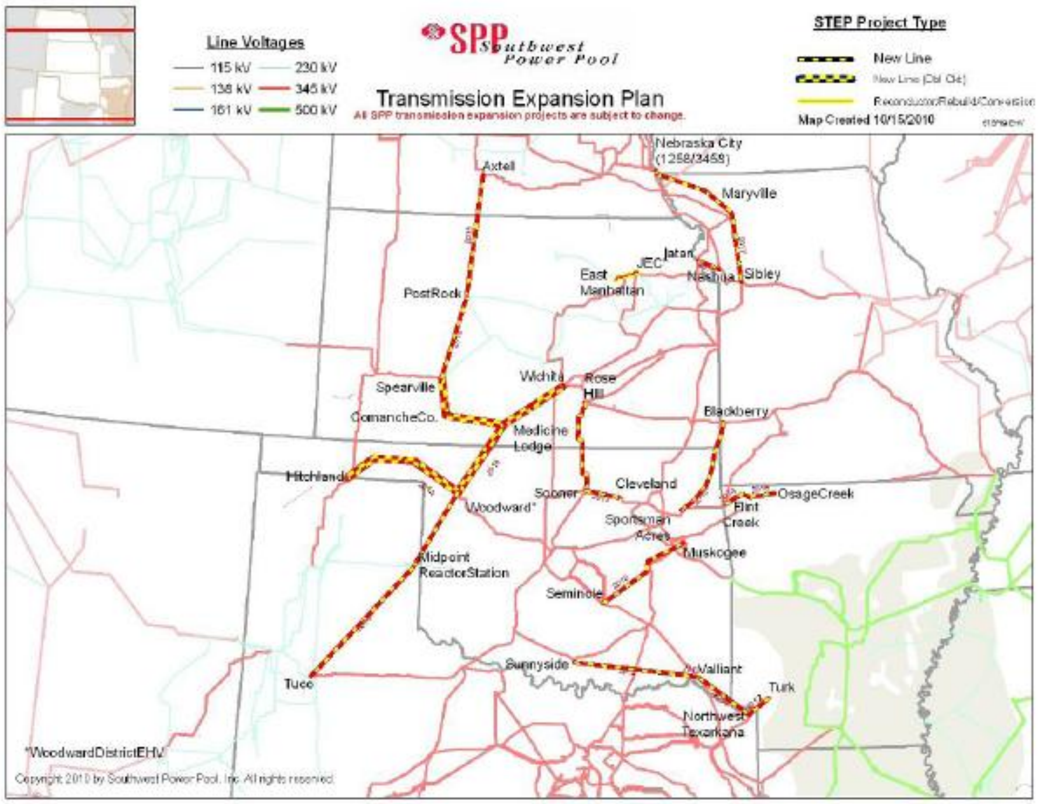
UPGRADE TYPE	2010 STEP (NEAREST 10 MILLION)
2010 Priority Projects*	$1,420
2009 Balanced Portfolio*	$820
Transmission Service Request and Generation Interconnection Service Agreements*	$650
Reliability – Base Plan*	$1,220
Reliability – Other	$540
Sponsored Upgrades	-
SPP Subtotal	**$4.65B**
Non-OATT Upgrades	$420
STEP Appendix A Total**	**$5.1B**

**Has filed Service Agreement or is Board Approved*
***SPP STEP Appendix A includes a breakdown of projects in the 10-year horizon*

[5] 2010 STEP: http://www.spp.org/publications/2010_SPP_Transmission_Expansion_Plan_01-28-11.pdf

[6] SPP Priority Projects Phase II Final Report: http://www.spp.org/publications/Priority%20Projects%20Phase%20II%20Final%20Report%20-%204-27-10.pdf

Figure 6: SPP Transmission Expansion Plan



Transmission improvements identified in the STEP and were included in the transmission models for this IRP. Some of the benefits provided by these improvements include reliability and the capacity for expansion of Oklahoma's abundant wind energy. A list of projects OG&E plans to construct can be found in Schedule J. Transmission system expansion provides benefits to members throughout the SPP; therefore, the costs of all projects constructed in the SPP are shared through various cost allocation methods, depending on the type of project.

E. Needs Assessment

Capacity needs are defined as the additional capacity required to meet the Company's customer requirement and to satisfy SPP's minimum 12% planning capacity margin requirement. Section 4.3.5 of the SPP Criteria establishes the basis and defines the required minimum capacity planning reserve margin for SPP members as follows:

> "The SPP performs generation reliability assessments to examine the regional ability to maintain a North American Electric Reliability Council ("NERC") based target probabilistic Loss of Load Expectation ("LOLE") standard of no more than one day in ten years. Historical studies indicate that the LOLE of one day in ten

years minimum can be maintained with a minimum capacity margin between 10-11%. Based on this, the SPP has established that each control area is required to maintain a minimum planned capacity margin of 12% for steam-based utilities and minimum planned margin of 9% for hydro-based utilities."

Therefore, OG&E is required to maintain capacity levels that allow for a minimum of 12% margin between capacity and demand. This calculation is shown in the following equation:

$$\text{Capacity Margin \%} = \frac{\text{(Total Net Dependable Capability) - (Net On System Demand)}}{\text{(Total Net Dependable Capability)}}$$

Table 14 utilizes the above equation to provide a ten-year capacity need forecast. This table includes all resources currently owned or under contract by OG&E. This table also includes OG&E's load responsibility and capacity margins. The resource gap, or capacity needed to satisfy customer demand and the SPP minimum 12% margin, is shown as Needed Capacity.

Table 14: Planning Capacity Margin

MW		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Resources	Owned Capacity	6,418	6,418	6,484	6,484	6,484	6,484	6,484	6,484	6,484	6,484
	Purchase Contracts	455	455	455	455	455	455	453	453	333	333
	Total Capability	6,873	6,873	6,939	6,939	6,939	6,939	6,937	6,937	6,817	6,817
Demand	Load Forecast	6,104	6,172	6,228	6,317	6,123	6,228	6,278	6,371	6,456	6,528
	Energy Efficiency	38	38	39	39	39	40	44	47	50	53
	Demand Response	184	280	400	452	488	506	525	529	534	537
	System Demand	5,882	5,853	5,789	5,826	5,596	5,681	5,710	5,795	5,872	5,938
Capacity Needs	Needed Capacity	-	-	-	-	-	-	-	-	-	-
	Capacity Margin	991	1,020	1,150	1,113	1,343	1,258	1,227	1,142	945	879
	Capacity Margin (%)	14.4	14.8	16.6	16.0	19.4	18.1	17.7	16.5	13.9	12.9

F. Scenarios

Scenarios are used to test each portfolio in a range of possible futures. This is done to determine the best portfolio in the expected future, as well as how each plan performs under changes in the expected assumptions. In this IRP OG&E is using three scenarios.

a) Reference Scenario

OG&E develops internal forecasts for load, fuel and CO_2 prices. The economy continues to slowly recover, shale gas keeps natural gas prices low and coal commodity price growth remains slow.

Table 15: Reference Scenario Prices

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CO_2 ($/tonne)	-	-	-	-	-	-	-	-	-	-

b) Ventyx Scenario

The Ventyx Midwest Reference Case High Environmental Scenario assumes the implementation of federal GHG legislation and national renewable energy standard beginning in 2015 which also increases the demand and price of natural gas.

Table 16: Ventyx Scenario Prices

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CO_2 ($/tonne)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

c) NYMEX Futures Scenario

On February 22, 2011, OG&E conducted an IRP stakeholder meeting to review assumptions for this IRP. One of the comments made in this meeting regarded the Reference Scenario natural gas price as too high compared to current prices. In response to this feedback, OG&E has included this scenario which applies the March 8, 2011 NYMEX forecast for natural gas.

Table 17: NYMEX Futures Scenario Prices

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas ($/MMBTU)	4.70	5.07	5.37	5.68	5.97	6.20	6.43	6.60	6.83	6.92
CO_2 ($/tonne)	-	-	-	-	-	-	-	-	-	-

G. Environmental Considerations

Uncertainty regarding environmental legislation and regulation is an important consideration in resource planning. This section describes several environmental considerations, which OG&E evaluated in connection with this IRP. OG&E continues to study the potential for additional new laws and regulations and to assess whether, and to what extent, such laws and regulations will impact OG&E's resource plan.

1. Renewable Energy Standards

In 2010, the Oklahoma Legislature passed HB 3028, the Oklahoma Energy Security Act which reads as follows:

> "The renewable energy standard shall be a goal that fifteen percent (15%) of all installed capacity of electricity generation within the state by the year 2015 be generated from renewable energy sources…"
>
> "(E)very electricity generating entity in Oklahoma may use energy efficiency and demand side management measures to assist the state in meeting its renewable energy standard. Provided, however, that demand side management may not be used to meet more than twenty-five percent (25%) of the overall fifteen percent (15%) renewable energy standard for the state."

Oklahoma is one of the leading states in wind generation development; therefore, additional wind resources, as described in the Resource Options section on page 15, are the primary renewable energy source for this IRP. With approximately 250 MW of additional wind generation, along with the demand side management programs, 15% of OG&E's installed capacity will be from renewable resources on or before the 2015 deadline.

2. Carbon Dioxide Restrictions

The United States Congress has considered legislation for reducing greenhouse gas emissions from mobile and stationary sources. One measure, passed by the House of Representatives in 2009, would have included a cap-and-trade system for reducing greenhouse gas output with a cap is set at graduated levels relative to 2005 CO_2 output. Congress as a whole, however, did not pass this or any similar legislation and, after the November 2010 elections, the future of greenhouse gas legislation is uncertain.

In the absence of federal legislation, the EPA has taken action to begin regulating CO_2 and other greenhouse gases using its existing authority under the Clean Air Act. Specifically, EPA agreed in December 2010 to issue Emission Guidelines under Section 111(d) of the Clean Air Act that could give rise to greenhouse gas emission limits for existing electrical generating units. Whether EPA has the authority to issue such Guidelines or otherwise regulate greenhouse gas emissions is currently the subject of several proposals being considered by Congress.

3. Regional Haze

In 2005, EPA, pursuant to the Clean Air Act, promulgated regulations to improve visibility in national parks and wilderness areas ("Regional Haze Regulations"). These Regional Haze Regulations require states, over approximately a 50-year period, to move toward the elimination of man-made impacts on visibility in Class I areas. In Oklahoma, the DEQ has developed rules that require certain resources to install Best Available Retrofit Technology ("BART"). The OG&E units affected are: Seminole 1, 2, and 3, Muskogee 4 and 5, and Sooner 1 and 2. In May 2008, OG&E submitted BART evaluations for its affected generating units at Muskogee, Seminole and Sooner Stations.

a) NO_x

The BART evaluations were performed in accordance with EPA guidelines and address two different types of emissions from these units that have the potential to affect visibility. The first type of emission addressed in the BART evaluation is nitrogen oxides ("NO_x"). The BART evaluations demonstrate that OG&E should install low NO_x combustion technology to minimize the creation of NO_x during combustion. One of the five factors considered in selecting BART is the cost effectiveness of available control technologies. According to EPA's cost-effectiveness guidelines, the low NO_x combustion techniques were shown to be cost effective. DEQ has agreed with the proposed BART determination for NO_x at the affected Seminole, Sooner and Muskogee units. On March 7, 2011, the EPA proposed to accept the Oklahoma State Implementation Plan ("SIP") with respect to the NO_x BART determination and proposed the installation of low NO_x combustion technology for reducing NO_x emissions under the Regional Haze Regulations.

b) SO_2

The second type of emission addressed in the BART evaluation is sulfur dioxide ("SO_2"). EPA established a presumptive BART emission rate for each of the affected coal-fired units at Muskogee and Sooner of 0.15 pounds of SO_2 emissions per MMBTU of heat input. This emission rate can be achieved with the installation of dry flue gas desulfurization, which also is known as a scrubber.

OG&E believes the presumptive BART emission rate for SO_2 does not apply if one performs a complete analysis of the five factors used to establish BART and determines a specific BART emission rate for each affected unit that considers that unit's particular characteristics and circumstances. The BART analysis performed by OG&E's consultant for the affected units at Muskogee and Sooner concludes that those units are unique in that they burn low sulfur coal that dramatically changes the cost effectiveness equation. As a result, the BART evaluation concluded that scrubbers were not cost effective under the Regional Haze Regulations and recommended emission limits that require the units to continue burning low sulfur coal.

In the Oklahoma SIP, the estimated capital cost for scrubbers at the affected coal units was $1.219 billion. In addition to the capital costs, and as shown in the Oklahoma SIP, OG&E expects to incur approximately $70 million annually to operate and maintain the scrubbers. During the first quarter of 2010, the State of Oklahoma submitted its SIP to the EPA. The Oklahoma SIP provided for the continued use of low sulfur coal with limited emission rates as shown in Table 18.

Table 18: Oklahoma SIP SO_2 Limits

SO_2 CONTROL	SOONER UNIT 1	SOONER UNIT 2	MUSKOGEE UNIT 4	MUSKOGEE UNIT 5
Hourly Emission Rate (30-day rolling average)	0.65 lb/MMBTU	0.65 lb/MMBTU	0.65 lb/MMBTU	0.65 lb/MMBTU
Emission Rate (30-day rolling average)	3,325 lb/hr	3,325 lb/hr	3,562 lb/hr	3,562 lb/hr
Annual Emission Rate (12-month rolling average)	0.55 lb/MMBTU	0.55 lb/MMBTU	0.55 lb/MMBTU	0.55 lbMMBTU
Combined Annual Emission Rate	19,736 TPY		18,096 TPY	

On March 7, 2011, the EPA issued a proposed rule in which the Agency rejected the Oklahoma SIP's SO_2 BART determinations and instead proposed a Federal Implementation Plan ("FIP") with a SO_2 emission limit of 0.06 lb/MMBTU. The FIP provides that this proposed emission limit can be achieved by either the installation of four scrubbers on the four affected coal-fired units or conversion of those four units to natural gas-fired units. The public comment period extends to May 23, 2011 and a final rule will occur sometime after that. OG&E is preparing comments to the proposed rule and evaluating the appropriate course of action. For the purposes of this IRP, OG&E evaluated several emission control options including the continued use of low sulfur coal, as well as the installation of scrubbers on all its coal-fired units, the conversion or replacement of those five coal-fired units with natural gas-fired units, the replacement of those five coal fired units with new or existing natural gas fired units and several hybrid scenarios.

4. Utility MACT Rule

On March 16, 2011, EPA issued proposed Maximum Achievable Control Technology ("MACT") regulations governing emissions of certain hazardous air pollutants from utility boilers. The proposal includes numerical standards for particulate matter, hydrogen chloride and mercury emissions from coal-fired boilers. In order to represent a mitigation measure for mercury, activated carbon injection costs were included on all portfolios that continued to use coal-fired generation. OG&E is studying whether it would be required to install any other control technologies like scrubbers or dry sorbent injection technology to comply with the proposed rule. Initiatives needed to comply with this proposed rule will be fully addressed in future IRPs. EPA is currently seeking public comment on the proposed rule.

5. Other Environmental Requirements

There are several other requirements pending or proposed under the Clean Air Act that could ultimately require some level of control at OG&E's facilities. For example, revised National Ambient Air Quality Standards ("NAAQS") issued by EPA could result in Oklahoma sources being required to reduce NO_x and SO_2 emissions. OG&E has assumed that none of these requirements will result in the installation of controls during the period covered by the IRP.

IV. RESOURCE PLANNING MODELING AND ANALYSIS

This section explains OG&E's analysis methods and presents results.

A. Development of Models and Portfolios

The assumption data provided in Section III is the basis for developing models and portfolios. The models and methodology for determining portfolios for analysis is described in this section.

1. Model Development

Incorporation of assumptions and understanding how each variable impacts others is the basis for model development. For this IRP, modeled data is analyzed on an incremental revenue requirement basis. The revenue requirement is composed of the return on rate base, total expenses and production cost as shown in Table 19. Return on rate base and expenses are modeled in spreadsheets while production cost is modeled in third party software.

Table 19: Revenue Requirement Components

RETURN ON RATE BASE	EXPENSES	PRODUCTION COST
Capital Investment	Depreciation	Fuel Cost
Accumulated Depreciation	Ad Valorem	Variable O&M
Accumulated Tax Depreciation	Fixed O&M	Emission Cost

2. Develop Distinct Portfolios

The following section describes the three steps used in developing portfolios to analyze in this IRP.

a) New Build Option Screening Process

The first step in developing portfolios is to decide which new resources should be considered for analysis. OG&E utilized the Annual Energy Outlook 2010, prepared by the EIA, for identifying proxy supply side resources. The proxy units are meant to represent a generic type of unit and not the specific manufacturer or technology to be placed into service. OG&E continually monitors the development of generation technology and will determine which manufacturer and technology provides the best value for its stakeholders when action needs to be initiated to meet OG&E's obligations. Three requirements were established for selecting supply side resource options to analyze. These supply side resource options and selection requirements are illustrated below in Table 20 and explained in the following subsections. Only resources that met all requirements were selected.

Table 20: New Supply Side Resource Option Screening Requirements

TYPE	TECHNOLOGY	NOMINAL CAPACITY (MW)	OVERNIGHT CAPITAL COST (2010$/KW)	PROVEN TECHNOLOGY	COST/ SCALE	PUBLIC SENTIMENT
Coal	Single Unit Advanced PC	650	3,167	Yes	Yes	
	Dual Unit Advanced PC	1,300	2,844	Yes	Yes	
	Single Unit Advanced PC w/ CCS	650	5,099			
	Dual Unit Advanced PC w/ CCS	1,300	4,579			
	Single Unit IGCC	600	3,565			
	Dual Unit IGCC	1,200	3,221			
	Single Unit IGCC with CCS	520	5,348			
Natural Gas	Conventional NGCC	540	978	Yes	Yes	Yes
	Advanced NGCC	400	1,003		Yes	Yes
	Advanced NGCC with CCS	340	2,060		Yes	Yes
	Conventional CT	85	974	Yes	Yes	Yes
	Advanced CT	210	665	Yes	Yes	Yes
	Fuel Cells	10	6,835			Yes
Uranium	Dual Unit Nuclear	2,236	5,335	Yes		
Biomass	Biomass CC	20	7,894	Yes		Yes
	Biomass BFB	50	3,860	Yes		Yes
Wind	Onshore Wind	100	2,438	Yes	Yes	Yes
	Offshore Wind	400	5,975	Yes		
Solar	Solar Thermal	100	4,692	Yes		Yes
	Small Photovoltaic	7	6,050	Yes		Yes
	Large Photovoltaic	150	4,755	Yes		Yes
Geo-thermal	Geothermal - Dual Flash	50	5,578	Yes		Yes
	Geothermal - Binary	50	4,141	Yes		Yes
MSW	Municipal Solid Waste	50	8,232	Yes		
Hydro	Hydro-electric	500	3,076	Yes		
	Pumped Storage	250	5,595	Yes		Yes

Yes = Meets requirement

(i) Proven Technology

In addition to providing construction and operating costs associated with the potential supply side resources, the Annual Energy Outlook 2010 also discusses how some technologies are more developed than others. For example, while carbon capture and sequestration is discussed as a solution to reduce CO_2 emissions, repeated utility scale facilities have not been developed and operated. Therefore this technology is not considered proven and is not included in a resource portfolio.

The advanced units in the Annual Energy Outlook are usually not proven technologies on a commercial scale. However, the Advanced CT is the same type of unit used in the Conventional CC and is commercially available. Furthermore, the cost of the Advanced

CT is also $300/kW less than the Conventional CT. Therefore, as a simplification, only the Advanced CT is used in this analysis.

(ii) Cost/Scale

The second requirement considers the cost and scale of the supply side option. The Biomass CC option has a cost of $7,894/kW. This is significantly more expensive than other renewable or baseload resource option; therefore it would not be a prudent addition to a portfolio. Likewise, the cost for a nuclear plant has greatly increased since the last resource plan and will not be considered in this plan. The generating output for Fuel Cells is less than what OG&E would need to meet system load growth and provide baseload energy. While these technologies may provide business development opportunities in the future, they will not be included in a 30 year plan until more information is available.

(iii) Public Sentiment

Several proposed coal fired generating units have received considerable opposition from environmental groups and the general public. Furthermore, the permitting of these coal plants has experienced resistance and there is no evidence that these trends will change in the future. For this reason, OG&E has decided not to consider coal fired generating units in this IRP.

b) Emission Control Options

As mentioned in the Environmental Considerations section, OG&E's coal fired steam plants could be affected by proposed regulations. While the current Regional Haze regulations only pertain to four of the five coal units in OG&E's fleet, other regulations could be proposed in the future that may include all coal units. In this IRP a select group of emission control options were analyzed to test alternatives for complying with current or potential rules. OG&E continues to monitor evolving emission control options, and no determination has been made as to which technologies might be used. The options included are:

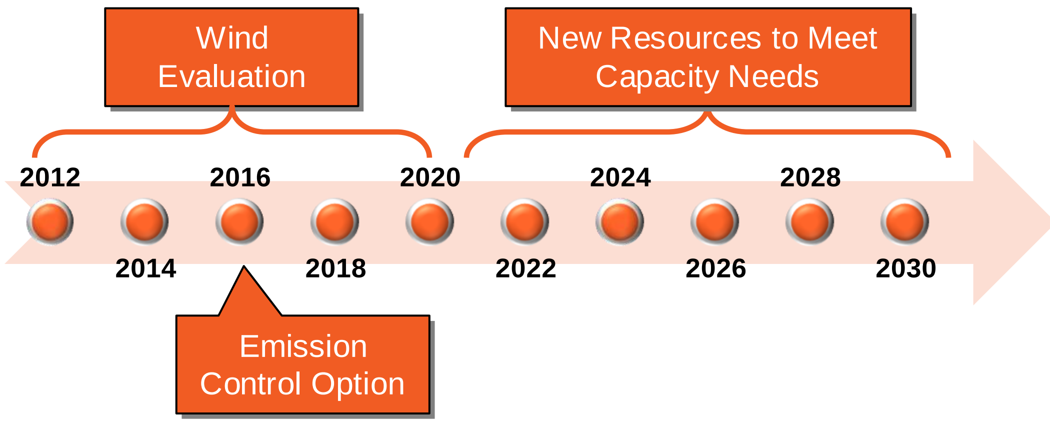
- Benchmark – OG&E's use of Low Sulfur Coal is accepted as BART
- Scrub – Installation of dry flue gas desulfurization with spray dryer absorbers (dry scrubbers) on all coal fired steam units.
- Hybrid Convert – Install scrubbers on three coal fired units and convert two units to burn natural gas
- Hybrid Replace – Install scrubbers on three coal fired units and replace two units with natural gas combined cycle units
- Convert[7] – All coal fired steam units are retrofitted to burn natural gas
- Replace – All coal fired steam units are retired and replaced with new natural gas combined cycle units

[7] Assumptions for this option include approximately $6 million to convert each coal unit to burn gas and approximately $110 million and $10 million to install gas pipelines to the Muskogee and Sooner Power Plants (respectively). Other costs associated with conversion of the coal units to burn gas, including but not limited to expansion of or improvements to existing transmission pipelines and gas storage arrangements, have not been determined and are not included in the assessment for this option.

c) Portfolio Development

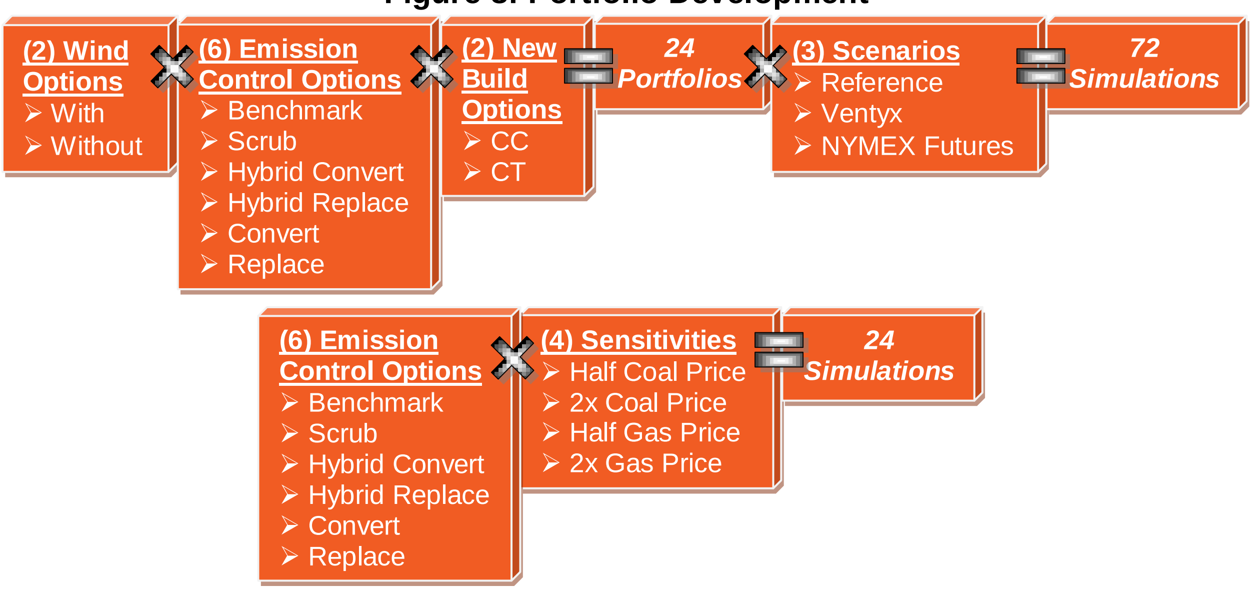
Considering the screening requirements for new supply side resources, three technologies are available for analysis: conventional natural gas combined cycle, advanced combustion turbine, and onshore wind. As shown in the Needs Assessment section, OG&E does not need to add capacity for the next ten years. However, the expansion of wind is based on energy, not capacity needs. To value additional wind resources, this IRP analyzes the affect of adding 250 MW of wind generation. The installation date is varied to analyze the timing of additional wind generation. The emission control options are evaluated in 2016 and to simplify the analysis, portfolios will either include CC units or CT units for future capacity needs starting in 2021. These installations are represented in Figure 7.

Figure 7: Analysis Timeline



Portfolios are developed by combining 2 wind options, 6 emission control options and 2 future capacity options for a total of 24 portfolios. Each portfolio is analyzed under 3 scenarios for a total of 72 simulations. Sensitivities are then performed for an additional 24 simulations. These combinations are depicted in Figure 8.

Figure 8: Portfolio Development



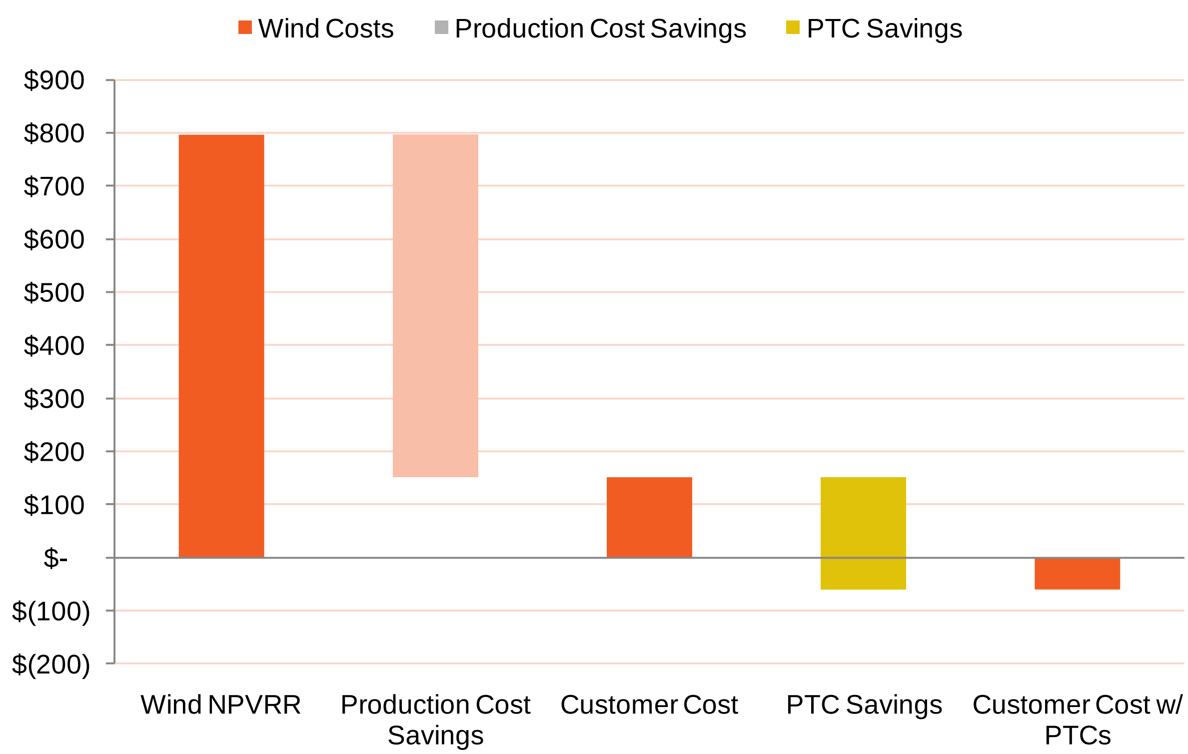
B. Portfolio Analysis

The following section describes analysis results for wind timing, emission control options and future resource expansions.

1. Evaluation of Future Wind

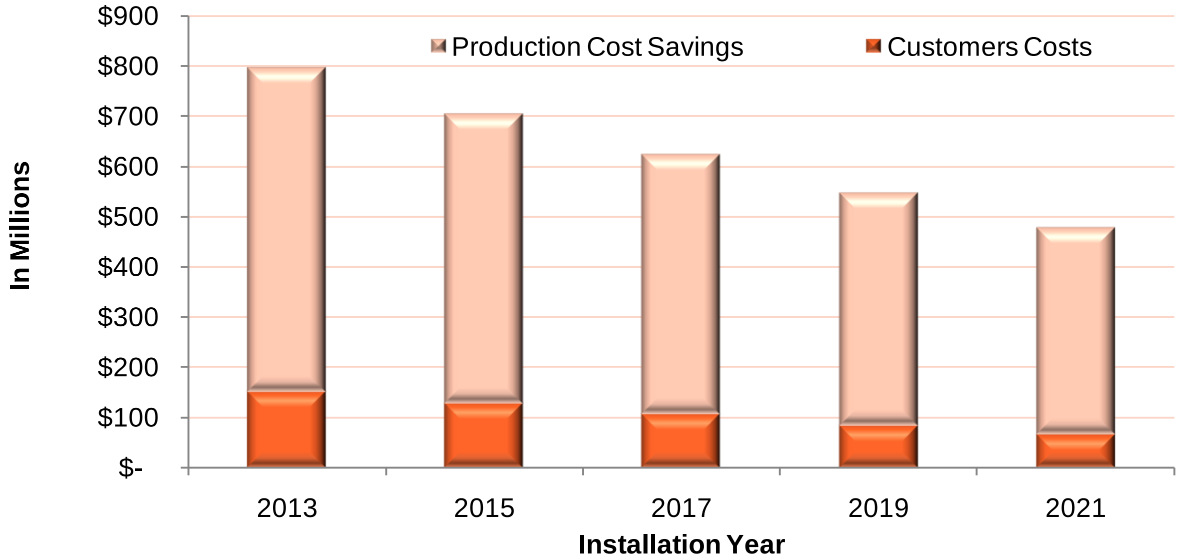
To analyze the economics of wind, two 125 MW wind energy facilities are assumed to be operational by 12/31/2012. This date was selected in order to qualify for Federal Production Tax Credits ("PTC"). Figure 9 represents the costs and benefits of wind energy using the assumptions in the Benchmark portfolio. The 30 year NPV of revenue requirements ("NPVRR") of the wind is just under $800 million. Production cost savings (fuel, variable O&M) reduces this amount to approximately $150 million. If the wind energy facilities qualify, PTCs may offer customer savings of approximately $60 million assuming PTCs are utilized starting in 2015.

Figure 9: 30 Year NPVRR Wind Evaluation with and without PTC



The installation date was then varied to analyze the timing of additional wind generation. These analyses reflect that delaying the construction of wind generation facilities reduces the NPVRR of the wind facilities yet also reduces production cost savings. As a result, absent the PTC savings assumed in 2012, adding two 125 MW wind energy facilities increases customer costs. This wind timing evaluation is shown in Figure 10.

Figure 10: Wind Timing Evaluation (NPVRR)



This IRP assumes OG&E would not be able to execute a RFP through the competitive bid process and have the wind facilities operational before 12/31/2012. Therefore, the remaining analysis does not include PTC savings.

2. Scenario Results

Scenario analysis involves changing multiple inputs and measures the impact of these changes on the results. To study the economic benefit of wind with emission control options, each portfolio was analyzed in each scenario with and without the addition of 250 MW of wind installed in 2013. The savings under each of these combinations is reflected as positive numbers below in Table 21

Table 21: Wind Savings Analysis, 30 Year NPVRR, ($Billions)

	REFERENCE	VENTYX	NYMEX	WEIGHTED AVERAGE*
Benchmark - CC	-0.23	0.05	-0.31	-0.22
Benchmark - CT	-0.15	0.15	-0.23	-0.14
Scrub - CC	-0.22	0.04	-0.30	-0.22
Scrub - CT	-0.16	0.15	-0.24	-0.16
Hybrid Convert - CC	-0.16	0.17	-0.23	-0.15
Hybrid Convert - CT	-0.10	0.24	-0.19	-0.09
Hybrid Replace - CC	-0.22	0.05	-0.29	-0.21
Hybrid Replace - CT	-0.16	0.14	-0.24	-0.16
Convert - CC	-0.09	0.27	-0.17	-0.08
Convert - CT	-0.08	0.30	-0.16	-0.06
Replace - CC	-0.25	0.00	-0.31	-0.24
Replace - CT	-0.20	0.09	-0.27	-0.19

** Weightings are: Reference 60%, Ventyx 10%, NYMEX 30%*

The 30 year NPVRR results for each of the three scenarios for portfolios without additional wind facilities are shown in Table 22.

Table 22: Emission Control Option Results, 30 Year NPVRR, ($Billions)

SCENARIO	REFERENCE	VENTYX	NYMEX	WEIGHTED AVERAGE
Benchmark - CC	21.4	31.3	20.4	22.1
Benchmark - CT	21.5	32.1	20.3	22.2
Scrub - CC	23.8	33.8	22.9	24.5
Scrub - CT	23.8	34.4	22.7	24.5
Hybrid Convert - CC	24.7	34.8	23.3	25.3
Hybrid Convert - CT	25.1	36.0	23.5	25.7
Hybrid Replace - CC	25.1	34.6	23.8	25.6
Hybrid Replace - CT	24.9	35.1	23.5	25.5
Convert - CC	27.0	37.5	24.9	27.5
Convert - CT	27.6	39.2	25.3	28.1
Replace - CC	27.3	36.1	25.4	27.6
Replace - CT	27.0	36.3	25.1	27.3

** Weightings are: Reference 60%, Ventyx 10%, NYMEX 30%*

C. Risk Evaluation

Sensitivity analysis and stochastic analysis were used to evaluate the risk of select portfolios in this IRP.

1. Sensitivity Results

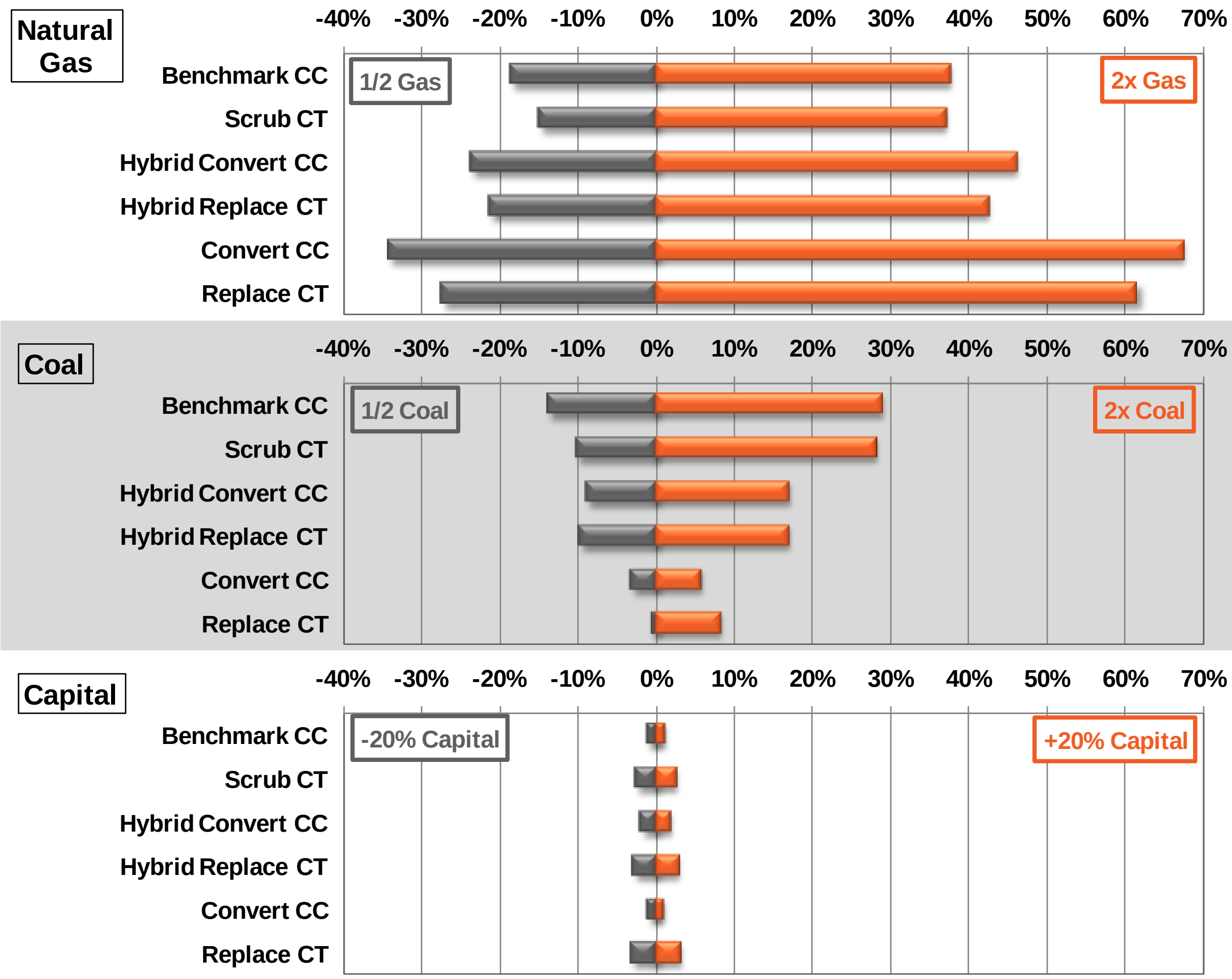
Sensitivity analysis involves changing a single input variable and measures the impact of that specific variable. Table 23 shows the sensitivities of these variables in the Reference portfolio.

Table 23: Emission Control Option Sensitivity Analysis, 30 Year NPVRR, ($Billions)

	Reference	1/2 Coal	2x Coal	1/2 Gas	2x Gas
Benchmark-CC	21.4	18.4	27.6	17.4	29.5
Scrub-CT	23.8	21.3	30.5	20.2	32.6
Hybrid Convert-CC	24.7	22.5	29.0	18.8	36.1
Hybrid Replace-CT	24.9	22.8	29.2	19.6	35.6
Convert-CC	27.0	26.1	28.7	17.8	45.4
Replace-CT	27.0	26.8	29.3	19.6	43.6

Figure 11 shows which variable has the largest impact on each portfolio, and which portfolio is the most sensitive to input changes.

Figure 11: Sensitivity Analysis Results, Percent Impact on Reference NPVRR

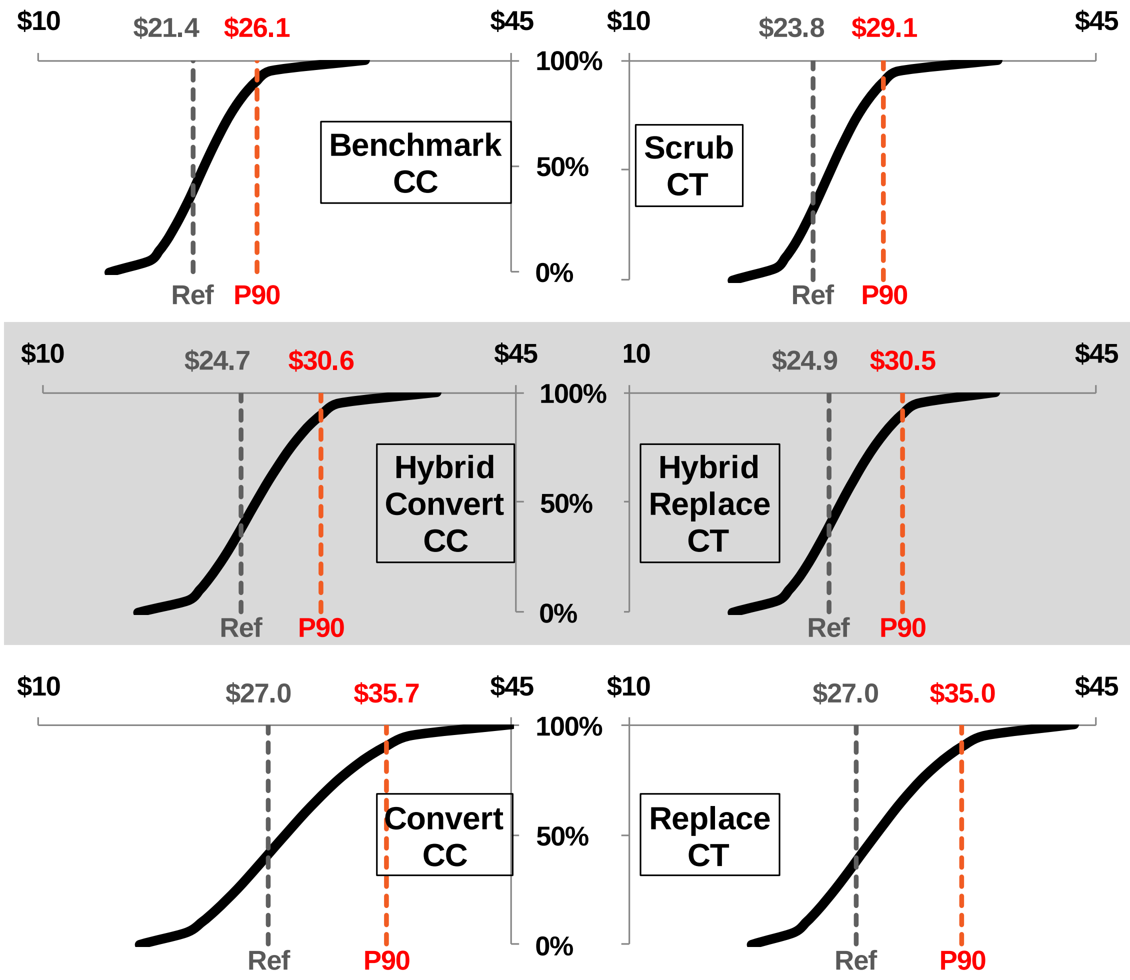


2. Stochastic Analysis

Stochastic analysis is a probabilistic method of varying multiple inputs to measure the impact on each portfolio. In general, lower revenue requirements and tighter bandwidths around expected revenue requirements (e.g., lower risk) are preferred. The Reference Scenario inputs varied in this analysis were natural gas, coal and capital cost.

These stochastic comparisons shown in Figure 12 represent a range from the reference scenario NPVRR value as shown in Table 22 to the 90th Percentile value ("P90"). The P90 represents the point on the probability curve where, based upon the analysis, there is a 90% certainty the revenue requirement will be less than that value.

Figure 12: Stochastic Analysis Results, 30-Year NPVRR, ($Billions)



D. SPP Integrated Marketplace

In 2009 the SPP Staff and stakeholders began developing the SPP Integrated Marketplace ("IM") for energy and operating reserves. Similar to other mature RTO/ISOs, the IM will incorporate the purely financial Day-Ahead and Transmission Congestion Rights markets as well as a Reliability Unit Commitment process and Real-Time Balancing Market. Utilizing these markets and processes, SPP will commit and dispatch resources to minimize the cost of energy and operating reserves to serve the SPP load.

Studies[8] have shown that implementation of a commitment based market will provide a more efficient operation of resources across the SPP footprint resulting in a net benefit to OG&E customers. The IM will impact the daily operation of OG&E's generation resources, and therefore their operating costs. To capture the impact of the IM on the

[8] http://www.spp.org/publications/Economies_of_Scale_Market_Benefits.pdf

portfolios, a market analysis was completed using the PROMOD IV® market simulation tool. The Ventyx PROMOD IV® program is used to calculate production cost through a security constrained economic dispatch for the SPP. The market analysis done for this IRP assumes the IM will be fully operational on January 1, 2015, and will continue through the study period which ends in 2041.

1. Integrated Marketplace Concepts

The IM is a significant change to current operations in the SPP footprint. An elementary understanding of a few concepts is necessary to understand this analysis. For more information regarding the IM, the SPP provides ample educational material on their website[9].

Unlike today, a company's generation will no longer be committed to serve its native load. In the IM, all resources in the SPP are committed and dispatched to serve the entire SPP load. Resources offer to sell energy and operating reserves into the IM and loads bid to purchase energy from the IM. Using simple supply and demand concepts, SPP determines which resources are committed and dispatched in the energy and operating reserve markets.

The IM will be a nodal market in which a Locational Marginal Price ("LMP") is calculated for every resource and load. The LMP consists of the marginal energy cost, marginal congestion cost, and marginal loss cost specific to the location that energy is being injected or withdrawn. At a very high level, SPP pays resources the LMP for each MWh injected and load pays SPP for each MWh withdrawn from the SPP transmission system. Therefore, the production cost seen by a company that has both generation and load, such as OG&E, can be described as:

$$(\textit{Generator Variable Cost}) - (\textit{Generator Revenue}) + (\textit{Load Cost}) = \textit{Production Cost}$$

The generator variable cost consists of fuel, variable O&M, and any other variable production costs associated with generating energy. The generator revenue is determined by multiplying the generated MWh by the LMP, and the load cost is determined by multiplying the hourly load by the associated LMP.

The SPP has 63GW of generating capacity, therefore it can be reasonably assumed that any small change in the system, such as adding a new 500MW unit, will not materially affect the energy clearing price over the course of a year. Due to the long run time of the market simulation, only the Reference Scenario was modeled which produced an LMP forecast. This LMP forecast was then used in a spreadsheet model to determine the generator variable costs and revenues of resource options, as well as OG&E's load cost. Only the costs of the resource options were modeled in the spreadsheet as costs for all other OG&E units were extracted from PROMOD IV®.

[9] http://www.spp.org/section.asp?pageID=138

2. Market Model

The market model consists of load, generator, and transmission data for the entire Eastern Interconnect, which Ventyx provides. The fuel forecasts were updated from the Ventyx provided forecasts to match those used in this IRP. The NERC regions simulated for this analysis were SPP, Entergy, MAPP, and MISO.

3. Generation Expansion

As part of the SPP Integrated Transmission Planning ("ITP") process, a generation expansion plan was developed by Black & Veatch for the SPP through 2030. For the study period beyond 2030, the same capacity mix was continued. This expansion plan is summarized in the table below.

Table 24: SPP Generation Expansion (MW)

	SPP NORTH			SPP SOUTH			TOTAL		
Resource Type	**CC**	**CT**	**Coal**	**CC**	**CT**	**Coal**	**CC**	**CT**	**Coal**
2015 – 2018	0	0	0	0	180	0	0	0	0
2019 – 2022	0	0	0	1,100	540	0	1,100	540	0
2023 – 2026	1,650	900	0	1,100	360	0	2,750	1,260	0
2027 – 2030	550	180	800	550	360	0	1,100	540	800
2031 – 2041	1,470	360	0	1,470	540	0	2,940	900	0
Total	**3,670**	**1,440**	**800**	**4,220**	**1,980**	**0**	**7,890**	**3,420**	**800**

In addition to thermal unit expansion, wind generation expansion was modeled using the results of a survey conducted by the SPP Cost Allocation Working Group ("CAWG"). This wind was spread over the NREL wind profiles, and modeled in the same way as discussed earlier. The total wind generation in the SPP is summarized below and represents the installed wind capacity delivered to the state in the year 2022.

Table 25: SPP Wind Expansion by State

	TX	**OK**	**KS**	**MO**	**NE**	**LA**	**NM**	**AR**	**TOTAL**
MW	3,156	2,697	1,741	1,271	924	332	264	254	**10,638**

4. Results

The benefits provided by a wind generator consist of the revenue paid to that generator for the energy it provides to the market. Based upon our current assumptions, the analysis reflected the revenue from the additional 250 MW of wind would not cover the associated incremental revenue requirement; therefore, it would not provide a benefit to OG&E customers.

Table 26: 30-Year NPV Wind Analysis in the IM ($Millions)

ADDITIONAL RATE BASE	**EXPENSES**	**REVENUE**	**NET COST (SAVINGS)**
414	381	-472	**112**

V. SCHEDULES

This section is intended to provide a tabular summary of each section as described in the OCC's Electric Utility Rules, Subchapter 37 of Chapter 35, section 4 (c).

Schedule A – Electric Demand and Energy Assumption

This schedule is the electric demand and energy sales assumptions from the 2010 Load Forecast. Details of these assumptions can be found in the Electric Demand and Energy Forecast section on page 11 and also in Appendix A – OG&E 2010 Load Forecast.

OG&E Peak Demand Forecast

MW	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wholesale	281	274	239	243	-	-	-	-	-	-
Retail	5,823	5,898	5,989	6,073	6,123	6,228	6,278	6,371	6,456	6,528
Total	6,104	6,172	6,228	6,317	6,123	6,228	6,278	6,371	6,456	6,528
Retail Growth	1.5%	1.3%	1.5%	1.4%	0.8%	1.7%	0.8%	1.5%	1.3%	1.1%

OG&E Energy Sales Forecast

GWH	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wholesale	1,616	1,537	1,274	1,274	-	-	-	-	-	-
Retail	27,501	27,865	28,364	28,828	29,224	29,682	30,013	30,501	30,950	31,369
Total	29,118	29,401	29,638	30,102	29,224	29,682	30,013	30,501	30,950	31,369
Retail Growth	1.9%	1.3%	1.8%	1.6%	1.4%	1.6%	1.1%	1.6%	1.5%	1.4%

Schedule B – Existing Resources

This schedule provides a summary of existing supply side and demand side resources. Details on this data can be found in the Resource Options section starting on page 11.

OG&E Planned Generation Resources

UNIT TYPE (PLANNING CAPACITY)	UNIT NAME	FIRST YEAR IN SERVICE	PEAK PLANNING CAPACITY (MW)	AVERAGE HEAT RATE (BTU/KWH)
Coal Fired Steam (2,553 MW)	Muskogee 4	1977	505	10,935
	Muskogee 5	1978	500	10,932
	Muskogee 6	1984	502	10,948
	Sooner 1	1979	522	10,223
	Sooner 2	1980	524	10,232
Gas Fired Steam (2,510 MW)	Horseshoe Lake 6	1958	159	11,253
	Horseshoe Lake 8	1968	381	12,210
	Mustang 1	1950	50	12,740
	Mustang 2	1951	51	12,724
	Mustang 3	1955	113	11,328
	Mustang 4	1959	253	11,207
	Seminole 1	1971	500	13,699
	Seminole 2	1973	500	12,166
	Seminole 3	1973	503	11,981
Combined Cycle (1,168 MW)	Horseshoe Lake 7	1963	227	11,283
	McClain*	2001	352	7,480
	Redbud*	2004	589	7,187
Combustion Turbine (237 MW)	Enid 1GT	1965	14	20,767
	Enid 2GT	1965	14	20,767
	Enid 3GT	1965	14	20,767
	Enid 4GT	1965	14	20,767
	Horseshoe Lake 9	2000	45	10,381
	Horseshoe Lake 10	2000	45	10,381
	Seminole 1GT	1971	17	N/A
	Mustang 5A	1971	32	14,647
	Mustang 5B	1971	32	14,647
	Woodward	1963	10	19,082
Purchase Power - Thermal (446 MW)	AES Shady Point	1991	320	11,817
	PowerSmith	1998	120	8,583
	SPA Hydro	N/A	6	N/A
Purchase Power - Wind (9 MW)	FPL Wind	2003	2	N/A
	Keenan	2010	4	N/A
	Taloga	2011	3	N/A
Owned Wind (16 MW)	Centennial	2007	7	N/A
	OU Spirit	2009	3	N/A
	Crossroads	2012	6	N/A
Total Net Dependability Capability			6,939	

** Represents OG&E owned interest*

Oklahoma EE Peak Demand and Energy Reduction

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand (MW)	36.6	36.6	36.6	34.6	32.7	30.7	30.7	30.1	27.6	25.2
Energy (MWh)	144,435	144,435	144,435	142,518	140,269	138,020	137,688	134,973	117,948	100,918

Arkansas Energy Efficiency Peak Demand and Energy Reduction

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand (MW)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.0	0.8
Energy (MWh)	4,738	4,738	4,738	4,738	4,738	4,738	4,738	4,431	3,307	2,759

Total System Energy Efficiency Peak Demand and Energy Reduction

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand (MW)	38.1	38.1	38.1	36.2	34.2	32.2	32.2	31.5	28.7	26.0
Energy (MWh)	149,173	149,173	149,173	147,256	145,007	142,758	142,426	139,404	121,255	103,677

Demand Response Assumption

(MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
DA - IVVC	8	17	26	37	48	60	75	75	75	75
Res DR	71	143	216	218	219	221	223	225	227	228
C & I DR	-	-	23	47	70	71	72	72	73	73
Load Curtailment	105	120	135	150	151	154	155	157	159	161
Total Reduction	184	280	400	452	488	506	525	529	534	537

Schedule C – Transmission Capability and Needs

This schedule provides a description of the OG&E transmission system as described in the Transmission Resources section on page 19. A further description of transmission adequacy and SPP projects are addressed in Schedule J.

OG&E Transmission Lines

VOLTAGE	500KV	345KV	161KV	138KV	69KV	TOTAL
MILES	47	911	205	1,864	1,465	4,492

Schedule D – Needs Assessment

This schedule provides the needs assessment for new generating resources for the next 10 years. A further description of these needs is found on page 22.

Planning Capacity Margin

MW		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Resources	Owned Capacity	6,418	6,418	6,484	6,484	6,484	6,484	6,484	6,484	6,484	6,484
	Purchase Contracts	455	455	455	455	455	455	453	453	333	333
	Total Capability	6,873	6,873	6,939	6,939	6,939	6,939	6,937	6,937	6,817	6,817
Demand	Load Forecast	6,104	6,172	6,228	6,317	6,123	6,228	6,278	6,371	6,456	6,528
	Energy Efficiency	38	38	39	39	39	40	44	47	50	53
	Demand Response	184	280	400	452	488	506	525	529	534	537
	System Demand	5,882	5,853	5,789	5,826	5,596	5,681	5,710	5,795	5,872	5,938
Capacity Needs	Needed Capacity	-	-	-	-	-	-	-	-	-	-
	Capacity Margin	991	1,020	1,150	1,113	1,343	1,258	1,227	1,142	945	879
	Capacity Margin (%)	14.4	14.8	16.6	16.0	19.4	18.1	17.7	16.5	13.9	12.9

Schedule E – Resource Options

This schedule provides a description of the supply and demand side options available to OG&E to address the needs identified in Schedule D and further explained starting on page 14.

New Supply Side Resources

TYPE	TECHNOLOGY	NOMINAL CAPACITY (MW)	HEAT RATE (BTU/ KWH)	OVERNIGHT CAPITAL COST ($/KW)	FIXED O&M COST ($/KW)	VARIABLE O&M COST ($/MWH)
Coal	Single Unit Advanced PC	650	8,800	3,167	35.97	4.25
	Dual Unit Advanced PC	1,300	8,800	2,844	29.67	4.25
	Single Unit Advanced PC w/ CCS	650	12,000	5,099	76.62	9.05
	Dual Unit Advanced PC w/ CCS	1,300	12,000	4,579	63.21	9.05
	Single Unit IGCC	600	8,700	3,565	59.23	6.87
	Dual Unit IGCC	1,200	8,700	3,221	48.90	6.87
	Single Unit IGCC with CCS	520	10,700	5,348	69.30	8.04
Natural Gas	Conventional NGCC	540	7,050	978	14.39	3.43
	Advanced NGCC	400	6,430	1,003	14.62	3.11
	Advanced NGCC with CCS	340	7,525	2,060	30.25	6.45
	Conventional CT	85	10,850	974	6.98	14.70
	Advanced CT	210	9,750	665	6.70	9.87
	Fuel Cells	10	9,500	6,835	350.00	-
Uranium	Dual Unit Nuclear	2,236	N/A	5,335	88.75	2.04
Biomass	Biomass CC	20	12,350	7,894	338.79	16.64
	Biomass BFB	50	13,500	3,860	100.50	5.00
Wind	Onshore Wind	100	N/A	2,438	28.07	-
	Offshore Wind	400	N/A	5,975	53.33	-
Solar	Solar Thermal	100	N/A	4,692	64.00	-
	Small Photovoltaic	7	N/A	6,050	26.04	-
	Large Photovoltaic	150	N/A	4,755	16.70	-
Geo-thermal	Geothermal - Dual Flash	50	N/A	5,578	84.27	9.64
	Geothermal - Binary	50	N/A	4,141	84.27	9.64
MSW	Municipal Solid Waste	50	18,000	8,232	373.76	8.33
Hydro	Hydro-electric	500	N/A	3,076	13.44	-
	Pumped Storage	250	N/A	5,595	13.03	-

Emission Control Technologies in 2010$

TECHNOLOGY	UNIT TYPE	CAPITAL COST ($M)	FIXED O&M COST ($M)	VARIABLE O&M COST ($/MWH)
Scrubber	Coal	308.8	7.3	2.52
Low NO_x Burners	Coal	14.3	0.9	-
Low NO_x Burners	Gas	9.6	0.6	-
Mercury Control- Activated Carbon Injection	Coal	2.1	0.3	0.57

Geo-Thermal Program Expansion Peak Demand and Energy Reduction

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand (MW)	0.2	0.4	1.2	2.7	4.9	8.1	11.9	16.2	21.1	27.0
Energy (MWh)	853	1,693	5,134	10,860	20,276	33,096	48,358	66,117	87,855	110,737

Schedule F – Fuel Procurement and Risk Management Plan

On May 15, 2010, OG&E filed a Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. A summary of this plan is provided below.

Fuel Procurement and Risk Management Plan

OG&E files an annual Fuel Supply Portfolio and Risk Management Plan with the Oklahoma Corporation Commission which details OG&E's fuel procurement and risk management plans. The plan was filed on May 15, 2010 under Cause No. PUD 200100095. This section is a summary of OG&E's fuel procurement and risk management plan.

Fuel Planning Process

In the spring of each year, OG&E develops a forecast of load responsibility for peak demand and energy requirements on a weather normalized basis for each month of the next calendar year. The Company then analyzes expected generation availability, fuel price assumptions and contractual commitments and obligations. Additional factors include such items as generation unit efficiencies, minimum loading requirements, ramp rates, maintenance schedules, allowances for forced outages, and gas storage status.

OG&E develops a dispatch commitment plan based on these inputs. This plan provides the Company with an estimate of annual usage by fuel type. The annual projection incorporates OG&E's assumed fuel requirements for the next year that is then broken down into monthly requirements. The assumed fuel burn is subject to change due to the potential purchase or sale of generation in the SPP hourly EIS market.

Resource Procurement Practices

1. Coal

Coal is procured under long-term contracts utilizing the widely accepted risk management laddering strategy. Contractual adjustments are made to the price of coal each quarter (up or down) due to quality variations. Currently, coal is purchased from four (4) producers located in the Southern Powder River Basin of Wyoming. Rail transportation is provided under long-term contracts with the BNSF railroad for the Sooner Plant. For the Muskogee plant, OG&E is currently operating under a Common carrier tariff service from the Union Pacific Railroad pending a determination by the Surface Transportation Board on a maximum jurisdictional threshold rated prescription.

2. Natural Gas

The Company acquires approximately 60% of its annual natural gas burn through a RFP process. OG&E obtains less than 0.1% of its natural gas requirements from older contracts with fixed prices and the remaining requirements are bought on a monthly, weekly, and daily basis. The key volumetric risk for natural gas procurement derives from securing sufficient supplies during the high electricity demand periods of April through October. OG&E currently transports its gas through the OGT pipeline and through the Enogex pipeline. OG&E has gas storage service under contract with Enogex[10] that allows OG&E's gas units to swing load in response to customer demands.

OG&E is currently considering alternatives such as long-term physical supply contracts to procure a portion of its forecasted natural gas requirements. These alternatives will be intended to provide the Company with reliable base-load supply. OG&E is also considering alternate pricing structures to help mitigate the volatility associated with natural gas prices.

3. Fuel Oil

Fuel oil is purchased through a competitive bidding process for delivery to the consuming plant. Fuel oil is primarily used for startup fuel at the coal-fired Sooner plant. Fuel oil is transported to the plants via truck.

Schedule G – Action Plan

This schedule outlines the proposed actions for the next five years. These actions are in accord with this IRP, and will position OG&E to complete the plan as described in this report.

DEMAND RESPONSE AND ENERGY EFFICIENCY

OG&E last updated its IRP in January 2010. This update builds on the conclusions in the January submittal that actions such as the timely termination of wholesale contracts, encouraging energy efficiency and demand response programs and other programs enabled by the smart grid offer benefits to customers. These actions are expected to reduce peak demand and, when combined with actions identified in the 2009 IRP, are projected to defer the need for new fossil fuel generation beyond the year 2020.

[10] Oklahoma Gas & Electric Co. and Enogex LLC are subsidiaries of OGE Energy Corp.

Actions to Reduce Peak Demand (MW)

		2012	2013	2014	2015	2016
Demand	Retail Peak Forecast	5,823	5,898	5,989	6,073	6,123
	Wholesale Peak Forecast	281	274	239	243	-
	Total Peak Forecast	6,104	6,172	6,228	6,317	6,123
Energy Efficiency and Demand Response	Energy Efficiency	38	38	39	39	39
	Distribution Automation	8	17	26	37	48
	Residential DR	71	143	216	218	219
	Commercial & Industrial DR	-	-	23	47	70
	Load Curtailment	105	120	135	150	151
	Total Peak Reduction	222	318	439	491	527
	System Peak Demand	5,882	5,853	5,789	5,826	5,596

RENEWABLE ENERGY

With the completion of the Crossroads Wind Farm, OG&E will have added 611 MW since 2008. OG&E has made no decision whether to issue a RFP for additional wind resources but will continue to monitor the market for renewable projects that benefit customers while contributing to the State's renewable energy goal.

TRANSMISSION

The 2010 STEP has identified projects that will be constructed over the next five years for reliability and economic purposes, including new generation additions such as wind. OG&E plans to participate in this expansion by constructing some of the projects that have been approved for construction by the SPP Board of Directors as listed in Schedule J.

INTEGRATED MARKETPLACE

The SPP is still developing the rules for an Integrated Marketplace concept to provide efficiencies and transparency to serving customers' energy needs throughout the SPP. This concept is expected to impact the way OG&E's generation units operate.

LONG TERM GAS CONTRACT

OG&E is considering alternatives such as long-term physical supply contracts to procure a portion of its forecasted natural gas requirements. These alternatives will be intended to provide the Company with reliable base-load supply. OG&E is also considering alternate pricing structures to help mitigate the volatility associated with natural gas prices.

MECHANICAL INTEGRITY

The MI Plan is the formalization, development and standardization of plant maintenance and reliability procedures, in an effort to mitigate safety risks and improve reliability of the Company's generation assets.

EMISSION CONTROL OPTIONS

On March 7, 2011, the EPA issued a proposed rule in which the Agency rejected the Oklahoma State Implementation Plan ("SIP") for SO_2 BART determinations and instead proposed a Federal Implementation Plan ("FIP") with a SO_2 emission limit of 0.06 lb/MMBTU. The FIP provides that this proposed emission limit can be achieved by either the installation of four scrubbers on the four affected coal-fired units or conversion of those four units to natural gas-fired units. The public comment period extends to May 23, 2011 and a final rule will occur sometime after that. OG&E is preparing comments to the proposed rule and evaluating the appropriate course of action.

Schedule H – Requests for Proposals

OG&E has made no decision whether to issue a RFP for additional wind resources but will continue to monitor the market for renewable projects that benefit customers while contributing to Oklahoma's renewable energy goal

Schedule I – Modeling Methodology and Assumptions

This schedule is a technical appendix for the data, assumptions, and descriptions of models needed to understand the derivation of the resource plan.

The table below explains who supplied each assumption and provides a reference for where this information is found in the IRP. Since the load assumption was provided in Schedule A, it has not been repeated here.

Assumption	Source	Page
Load	OG&E and The Cadmus Group, Inc.	7
Natural Gas	OG&E, Ventyx and NYMEX	24
Coal	OG&E,	24
CO_2	Ventyx	24

Reference Scenario Prices

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CO_2 ($/tonne)	-	-	-	-	-	-	-	-	-	-

Ventyx Scenario Prices

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CO_2 ($/tonne)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NYMEX Futures Scenario Prices

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Coal ($/MMBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas ($/MMBTU)	4.70	5.07	5.37	5.68	5.97	6.20	6.43	6.60	6.83	6.92
CO_2 ($/tonne)	-	-	-	-	-	-	-	-	-	-

The table below explains who supplied the information for each resource option and provides a reference for where this information is found in the IRP.

Resource	Source	Page
New Unit Characteristics	EIA	14
Existing Unit Characteristics	OG&E	13
Energy Efficiency	Frontier Associates	17
Demand Response	The Structure Group	18

Descriptions of Software Tools

OG&E utilizes two software programs for production cost modeling.

GenTrader®

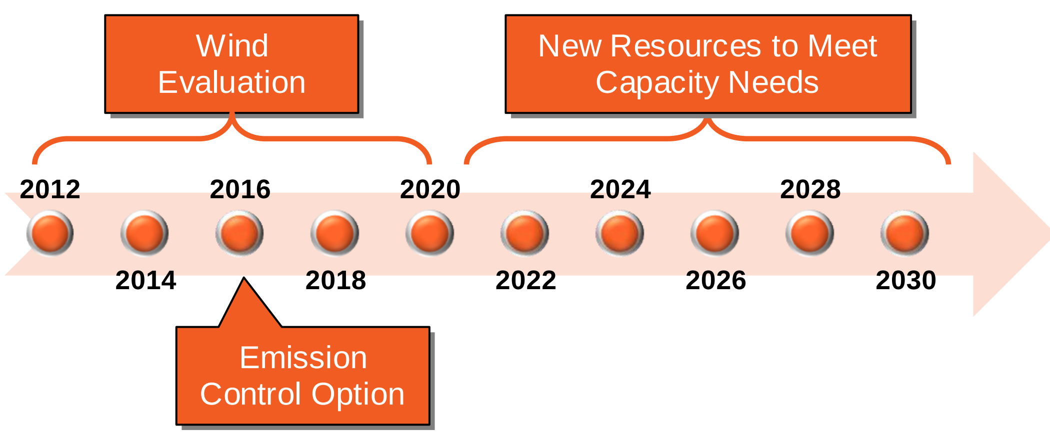
The GenTrader ® software provided by Power Costs, Inc. is designed to model complex portfolios of power and fuel resources, including generators, contracts, options, and ancillary services in great detail. Some of the functionalities include: multiple and concurrent fuel and emission limits, multi-stage combined-cycle modeling, ancillary services like regulations and spinning reserve as well as energy limited contracts. GenTrader® is used to simulate OG&E owned or contracted units serving OG&E's load

PROMOD IV®

The PROMOD IV® software provided by Ventyx is the industry-leading Fundamental Electric Market Simulation software, incorporating extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations. PROMOD IV® is used to model the SPP Integrated Marketplace

The following figure describes when resources were put in service in each portfolio to meet capacity needs.

Analysis Timeline



Schedule J – Transmission System Adequacy

This schedule is a description of the transmission system adequacy over the next 10 years. SPP evaluates system adequacy and develops a transmission expansion plan to determine what improvements are necessary to ensure reliable transmission service. The 2010 STEP[11] describes improvements necessary for regional reliability, zonal reliability, long-term tariff studies due to transmission service requests and transmission owner sponsored improvements. Included in below is a subset of the 2010 STEP that OG&E has committed to construct.

Estimated Capital Expenditures for OG&E Committed Projects

YEAR	DESCRIPTION	TYPE OF UPGRADE	TYPE	COST ($M)
2011	Muldrow to 3rd Street	Substation Upgrade	Zonal - Sponsored	0.1
2011	Arkansas Conversion Project	Convert 69kV to 161kV	Zonal - Sponsored	26.7
2011	Rocky Point to Ardmore 69kV	Reconductor Line	Transmission Service / Base Plan Funded	0.5
2011	Sunnyside to Uniroyal 138kV	Substation Upgrade	transmission service	0.1
2011	Dillard to Healdton Tap 138kV	Substation Upgrade	Transmission Service / Base Plan Funded	0.3
2013	Crescent to Cottonwood Creek	Convert 69kV to 138kV	Regional Reliability / Base Plan Funded	4.5
2011	Bellcow Substation & Transmission Line	New Substation, New Line	Zonal - Sponsored	17.9
2011	Johnson County Project	New Substation, New Lines, New 345kV/138kV Transformer	Zonal - Sponsored	27.6
2011	Gracemont 345kV	New Substation, New 345kV/138kV Transformer	Balanced Portfolio	14.7
2011	Alva 69kV	Substation Upgrade	Zonal - Sponsored / Byway Funded	0.1
2011	Wells 69kV	New Capacitors	Regional Reliability / Byway Funded	0.4
2011	Little River Lake 69kV	New Capacitors	Regional Reliability / Byway Funded	0.4
2011	Cushing Oil	New Capacitors	Base Plan	0.4
2011	Tiger Creek	New Capacitors	Base Plan	0.3
2012	Russett to WFEC Russett 138kV	Substation Upgrade	Base Plan	0.3
2012	VBI to Adabell	Substation Upgrade	Base Plan	0.9
2012	Sooner to Rose Hill 345kV	New Line	Regional Reliability / Base Plan Funded	57.8

[11] 2010 STEP: http://www.spp.org/publications/2010_SPP_Transmission_Expansion_Plan_01-28-11.pdf

YEAR	DESCRIPTION	TYPE OF UPGRADE	TYPE	COST ($M)
2012	Sooner to Cleveland 345kV	New Line	Balanced Portfolio	64.8
2012	Hugo to Sunnyside 345kV	New Line	Transmission Service / Base Plan Funded	187.0
2012	Sunnyside 345kV to Sunnyside 138kV	Install 2nd Bus tie Transformer	Transmission Service / Base Plan Funded	6.8
2012	Oak Park to Johnson 161kV	New Line	Regional Reliability / Base Plan Funded	3.2
2012	Johnson to Massard	Convert 69kV to 161kV	Regional Reliability / Base Plan Funded	5.5
2012	Arcadia 345kV to Arcadia 138kV	Install 3rd Bus tie Transformer	Transmission Service / Byway Funded	8.5
2013	VBI	Substation Upgrade	Zonal - Sponsored	0.0
2013	Fort Smith to Colony 161kv	Reconductor Line	Regional Reliability / Base Plan Funded	2.5
2013	Seminole to Muskogee 345kV	New Line	Balanced Portfolio	179.1
2013	Canadian River 345kV	New Substation Tapping Pittsburg to Muskogee Line	Regional Reliability / Base Plan Funded	5.5
2013	Arcadia 345kV	Convert to breaker and a half configuration	Highway	5.0
2014	Woodward EHV to Stateline (Tuco) 345kV	New Line and 2nd Bus tie Transformer	Balanced Portfolio	120.0
2014	Woodward EHV to Hitchland 345kV	New Double Circuit 345kV Line	High Priority / Highway Funded	178.6
2014	Woodward EHV to Medicine Lodge 345kV	New Double Circuit 345kV Line	High Priority / Highway Funded	134.4
2015	Cushing Project 69kV to 138kV	Convert 69kV to 138kV	Regional Reliability / Byway Funded	16.0
2016	HSL East to HSL West 69kV	Substation Upgrade	Zonal - Sponsored	0.3
2017	Fort Smith 500kV to 161kV	Install 3rd Bus tie Transformer	Transmission Service / Base Plan Funded	11.0
2017	VBI North 69kV Circuit 1, Upgrade Current Transformer	Substation Upgrade	Transmission Service / Base Plan Funded	0.1
2019	Arcadia to Redbud 345kV Circuit 3	New Line	Transmission Service / Highway Funded	19.0
2019	Bryant to Memorial 138kV	Substation Upgrade	Transmission Service / Byway Funded	0.3

Transmission system expansion provides benefits to members throughout the SPP; therefore, the costs of all projects constructed in the SPP are shared through various cost allocation methods, depending on the type of project.

Schedule K – Resource Plan Assessment

This IRP assessed the need for additional resources to meet reliability, cost and price, environmental, and other criteria established by the OCC, the State of Oklahoma, the APSC, the Southwest Power Pool, North American Electric Reliability Council, and the Federal Energy Regulatory Commission. All criteria were met by all portfolios considered in this IRP, in the base line condition. These criteria were also met in scenarios and uncertainties which included variations in load growth, fuel prices, emissions prices, environmental regulations, technology improvements, demand side resources, and fuel supply, among others. This plan provides a comprehensive analysis of the proposed options.

Schedule L – Proposed Resource Plan Analysis

This IRP demonstrates that all proposed options meet all planning criteria as outlined in Schedule K. The proposed action plan outlined in Schedule G best meets these criteria. Documentation of the planning analysis and assumptions used in preparing this analysis are described in Schedule I.

VI. APPENDICES

Appendix A – OG&E 2010 Load Forecast
Appendix B – OG&E 2010 Capability Report
Appendix C – Annual Portfolio NPVRR for Reference Scenario
Appendix D – OGE 2011 IRP Oklahoma Collaborative Technical Conference

Appendix A – OG&E 2010 Load Forecast

Final Report

2010 OG&E Load Forecast

Prepared by:
OGE Research and Analysis Department
The Cadmus Group

September 14, 2010

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Table of Contents

EXECUTIVE SUMMARY

This report presents Oklahoma Gas & Electric Services' (OG&E) 2010 load forecasts. It describes both peak demand and energy forecasting models developed by OG&E and The Cadmus Group with input from OG&E's Load Forecasting Team.

The 2010 retail sales forecast utilized the revenue class-based econometric modeling framework that has been in place for over a decade. The 2010 load responsibility peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility series. The hourly modeling approach has been used since the 2000 forecast.

The load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of electricity prices for price-sensitive customer classes. The final energy and demand forecast includes Federal Energy Regulatory Commission (FERC) jurisdictional wholesale contracts as post-modeling adjustments.

2010 Energy Sales Forecast

The 2010 retail energy forecast is based on retail sector-level econometric models representing OG&E's Oklahoma and Arkansas service territories. Historical and forecast economic variables (drivers) are provided by the Center for Applied Economic Research at Oklahoma State University (OSU).

In past forecasts, Moody's Economy.com provided economic drivers that were used to predict energy sales in OG&E's Arkansas service territory. This year, OG&E made the decision to purchase forecasts of economic drivers for both Oklahoma and Arkansas from OSU. The move from Moody's Economy.com to OSU was made because consolidating the sources for economic drivers would simplify the load forecasting process. By using a single source for economic drivers OG&E has eliminated the need to adjust the Arkansas drivers to follow the same assumptions as the Oklahoma drivers.

In 2007 the Oklahoma economic driver series were adjusted for structural changes in the state's economy. OSU's research had revealed a "billionaire" effect that inflates the real income and gross state product series that are critically important in forecasting OG&E's energy sales.
Table 1 below, compares the growth rates of 2010 and 2009 forecast drivers. The "ex-energy" variables, where the "billionaire" effect is removed, are compared to their unadjusted counterparts. The comparison reveals:

- That the difference in growth rates between the ex-energy series and their counterpart is still a significant factor, and is in fact increasing for several of the series compared to the forecasts from 2009.
- Most of the 2010 drivers exhibit lower growth rates as a result of the recent economic downturn.

Table 1. Economic Driver Growth Rate Comparison

Economic Drivers	2010 Drivers Average Growth Rate 2010 to 2020	2009 Drivers Average Growth Rate 2010 to 2020	2010 Drivers Average Growth Rate 2010 to 2015	2009 Drivers Average Growth Rate 2010 to 2015	2010 Drivers Average Growth Rate 2016 to 2020	2009 Drivers Average Growth Rate 2016 to 2020
Real Personal Income OKC	4.04%	3.83%	3.93%	3.67%	4.17%	4.06%
Real Personal Income Ex Energy OKC	3.54%	3.36%	3.50%	3.26%	3.59%	3.52%
Difference	**0.50%**	**0.47%**	**0.43%**	**0.41%**	**0.58%**	**0.55%**
Real GSP	2.28%	3.04%	1.78%	2.74%	2.88%	3.49%
Real GSP Ex Energy	2.21%	2.60%	2.05%	2.53%	2.40%	2.70%
Difference	**0.07%**	**0.44%**	**-0.27%**	**0.20%**	**0.48%**	**0.79%**

Underlying Fundamentals

Over the last decade the Oklahoma economy has outperformed the nation during recessions due to robust growth in the energy sector. Prudent lending practices and limited direct erosion of the consumer balance sheet allowed Oklahoma to enter the most recent recession later than the nation. The effects of the recession in Arkansas have been dampened due to the limited influence of low energy prices and employers delaying plans to outsource manufacturing operations. Both states have fared better than the nation, and are poised to recover when energy prices increase and the rest of the country returns to positive economic conditions.

Energy Sector

The OSU forecast drivers anticipate the price of oil hovering around $70/barrel, and natural gas around $5 per million btu's in 2010. These prices are close to the threshold where energy switches from providing a net boost to restricting growth in the state economy. While the price of oil is beginning to increase, it has been around $70 a barrel for most of the year, and the price of natural gas has been below $4.50 per million btu's. The Energy Information Administration (EIA) forecast[1] suggests that natural gas will remain below $5 per million btu's through the end of the year, with oil climbing to an average of $80 a barrel in the fourth quarter.

After experiencing considerable decline in activity in 2009, the energy sector in Oklahoma is seeing a considerable recovery in 2010. Since hitting a low of $1.84 per mmBtu on September 4th, 2009, the price of natural gas has rebounded to nearly $4.50 per mmBtu in 2010. This has allowed for the continued development of conventional oil and natural gas wells in the Arkoma Basin in western Oklahoma along with the Woodford Shale in southeast Oklahoma and the Fayetteville Shale in central Arkansas.

The recovery of the energy sector in Oklahoma will play a vital role in the overall growth of the Oklahoma economy. As energy prices increase so will revenue collections for Oklahoma. The gross production tax on natural gas yielded $24 million in July, which is $1.9 million or 8.4 percent above the prior year. Oklahoma has made efforts to diversify the economy, but the energy sector is still the foundation for the Oklahoma economy.

[1] The Energy Information Administration: Short-term Energy Outlook, http://www.eia.doe.gov/emeu/steo/pub/contents.html

Retail Electric Prices

The retail electric prices used in the forecast include the revised cost of operations along with riders for various other projects. There are riders for OG&E's Smart Grid and the OU Spirit wind farm included in the price forecast. Additionally, the price forecast includes the cost of new transmission. In 2010 there was a fuel clause adjustment paid to customers. The fuel adjustment offset most of the rate increase in 2010, so customers experienced a negligible increase in price during 2010. However, the conclusion of the fuel clause adjustment at the end of 2010 will make the effective price increase from 2010 to 2011 approximately 17 percent. A price increase of this magnitude is responsible for the relatively low growth rate in 2011.

Price Elasticity of Demand

The own-price elasticity of demand for the residential sector in Oklahoma has been restricted to -0.1 from 2010 to 2012 and -0.2 from 2013 to 2020. The unrestricted estimate of own-price elasticity of demand for the residential sector in Oklahoma is -0.24. This unrestricted estimate is relatively more elastic than the 2009 estimate of -0.05, but it remains highly inelastic when compared to other goods. The main cause of the disparity between the 2009 and 2010 estimates is the use of an all-good price index instead of an energy specific price index to adjust prices for inflation. The all-good price index more accurately reflects the effects of inflation on a consumer's budget and their energy consumption decisions. Own-price elasticity of demand was restricted due to the impacts it would have on the forecast when combined with unprecedented price increases in the short-run. The restrictions limit the effect of prices in the near-term and allow for an increased long-term response to changes in the retail price of electricity in the Oklahoma residential sector. The elasticity estimates in other sectors were relatively unchanged from the 2009 forecast, so there were no other restrictions implemented.

CO_2 Emission Regulations

The potential for limits on carbon dioxide emissions has increased the degree of uncertainty relating to future operating expenses. To understand the potential effects of carbon legislation on future energy sales and peak demand an alternative scenario was developed for the load forecast. The scenario is based on the assumption that there will be limits on carbon dioxide emissions beginning in 2012. The projected emissions regulations will put upward pressure on energy prices and increase overall operating expenses. This will result in an increased price forecast and lower overall energy sales and peak demand. See the appendix for the corresponding forecast scenario output.

Table 2. Alternative Scenario Cost of CO2 Emissions

Year	Nominal CO2 Price ($/tonne)
2012	$15.69
2013	$17.67
2014	$19.72
2015	$21.81
2016	$23.46
2017	$25.22
2018	$27.11
2019	$29.16
2020	$31.34

Energy Sales Forecast

The 2010 retail energy sales forecast is summarized in Table 3 below. The table also contains the energy sales forecast adjusted for wholesale sales contracts and line losses to wholesale and retail sales. The forecast (and 2009 actual sales) is based on normal weather in both Oklahoma and Arkansas. The underlying retail forecast is anticipated to grow at an average annual rate of 1.3%. The energy sales forecast adjusted for wholesale sales projects average growth at 0.86%, with the difference relative to retail growth due to expiring wholesale contracts. Table 4 and Table 5 provide the annual growth rates of the retail sales forecasts for all sectors in Oklahoma and Arkansas, respectively. Table 6 presents the forecasted annual growth rates of the different wholesale sales contracts. Note that by 2015, all wholesale contracts will have expired.

Table 3. 2010 Retail and Wholesale Energy Sales Forecasts

Year	Energy Forecast (MWh) Including Wholesale Sales and Line Losses	Energy Growth Rates Including Wholesale Sales and Line Losses	Retail Energy Forecast (MWh)	Retail Energy Growth Rates
2009	27,800,572		24,640,489	
2010	28,228,196	1.54%	24,982,578	1.39%
2011	28,413,888	0.66%	25,218,899	0.95%
2012	27,908,465	-1.78%	25,704,426	1.93%
2013	28,169,061	0.93%	26,044,153	1.32%
2014	28,387,249	0.77%	26,510,774	1.79%
2015	28,828,465	1.55%	26,945,009	1.64%
2016	29,224,415	1.37%	27,315,090	1.37%
2017	29,681,602	1.56%	27,742,408	1.56%
2018	30,013,134	1.12%	28,052,280	1.12%
2019	30,501,277	1.63%	28,508,530	1.63%
2020	30,949,656	1.47%	28,927,616	1.47%

Table 4. 2010 Oklahoma Retail Sales Forecast Growth Rates by Sector

Year	Residential	Commercial	Public Authority	Street lighting	Industrial	Petroleum
2010	1.21%	1.17%	0.26%	1.96%	0.50%	0.50%
2011	0.76%	0.82%	2.17%	1.40%	0.50%	0.50%
2012	1.80%	2.89%	2.61%	1.37%	0.50%	0.50%
2013	1.38%	1.79%	1.38%	1.37%	0.50%	0.50%
2014	2.33%	2.20%	1.73%	1.38%	0.50%	0.50%
2015	1.46%	2.51%	2.19%	1.37%	0.50%	0.50%
2016	1.11%	1.95%	2.08%	1.36%	0.50%	0.50%
2017	1.18%	2.41%	2.59%	1.36%	0.50%	0.50%
2018	0.53%	1.66%	2.16%	1.35%	0.50%	0.50%
2019	1.40%	2.31%	2.59%	1.34%	0.50%	0.50%
2020	1.15%	2.06%	2.21%	1.34%	0.50%	0.50%

Table 5. 2010 Arkansas Retail Sales Forecast Growth Rates by Sector

Year	Residential	Commercial	Public Authority	Street Lighting	Industrial	Petroleum
2010	0.91%	1.33%	5.69%	0.73%	12.02%	5.00%
2011	0.54%	3.05%	5.59%	0.52%	0.50%	0.50%
2012	3.03%	4.51%	3.82%	0.60%	0.50%	0.50%
2013	2.02%	2.76%	3.57%	0.65%	0.50%	0.50%
2014	2.32%	3.25%	3.28%	0.66%	0.50%	0.50%
2015	2.31%	3.22%	3.45%	0.65%	0.50%	0.50%
2016	2.08%	3.06%	3.83%	0.64%	0.50%	0.50%
2017	2.04%	2.91%	4.14%	0.62%	0.50%	0.50%
2018	1.87%	2.69%	4.12%	0.61%	0.50%	0.50%
2019	1.90%	3.10%	4.11%	0.60%	0.50%	0.50%
2020	2.06%	3.52%	4.41%	0.59%	0.50%	0.50%

Table 6. 2010 Wholesale Sales Forecast Growth Rates

Year	Municipal	AVEC	SPA	OMPA	MDEA	Total
2010	-11.64%	-0.91%	7.11%	4.20%	-2.55%	-0.16%
2011	-8.43%	-6.41%	1.88%	0.00%	0.00%	-4.36%
2012	-79.82%	-100.00%	-58.21%	0.00%	0.00%	-70.33%
2013	-100.00%		-100.00%	0.00%	-46.56%	-25.26%
2014				-100.00%	-66.67%	-92.32%
2015					-100.00%	-100.00%

2010 Load Responsibility Peak Demand Forecast

The 2010 load responsibility forecast relies on an hourly econometric model specification first used for the 2000 forecast. The modeling framework reflects the following:

- Impact of different weekdays on hourly system load.
- Impact of different summer months on hourly system load.
- Influence of heat buildup during heat waves.
- Impact of the combined effects of humidity and warm temperatures.
- Non-linearity in the load and temperature relationships at very high temperatures.

As has been the case for the past several years, weather-adjusted retail energy sales are the main economic driver for the peak model.

Table 7 shows the actual 2009 retail load, along with the final load responsibility forecast, adjusted for wholesale loads and line losses, for 2010 and beyond. The forecast is based on average weather conditions over the past 35 years. Underlying retail peak loads are anticipated to grow at an average annual rate of 1.2% over the next decade, which is slightly less than the growth rate for retail energy sales.

Table 7. 2010 Load Responsibility Peak Demand Forecast

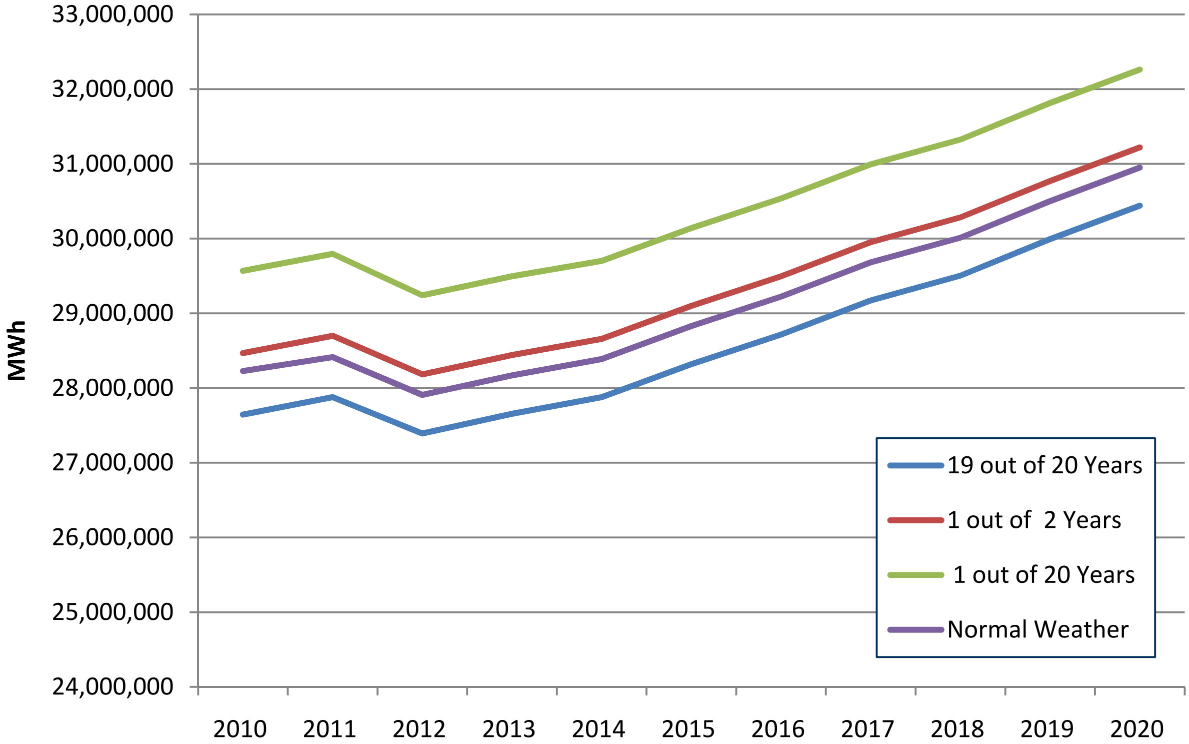
Year	Total Load Responsibility Peak Demand (MW) Forecast* (Average Weather)	Total Load Responsibility Growth Rates	Retail Load Responsibility Peak Demand (MW) Forecast (Average Weather)	Retail Load Responsibility Growth Rates
2009	5,917		5,617	
2010	6,012	1.62%	5,702	1.53%
2011	6,054	0.70%	5,736	0.60%
2012	5,874	-2.98%	5,823	1.51%
2013	5,937	1.07%	5,898	1.29%
2014	5,989	0.87%	5,989	1.54%
2015	6,073	1.41%	6,073	1.41%
2016	6,123	0.82%	6,123	0.82%
2017	6,228	1.71%	6,228	1.71%
2018	6,278	0.82%	6,278	0.82%
2019	6,371	1.47%	6,371	1.47%
2020	6,456	1.33%	6,456	1.33%

Weather Uncertainty

As is well known within the electric industry, and especially at OG&E, peak demand and energy sales are highly sensitive to year-to-year weather variations. Both can appear to decline even with positive economic growth when a hot year is followed by an unusually cool year. Conversely, if a hot year follows a cool year, energy sales and peak demand can increase even though there may be little or no economic growth. Weather uncertainty is represented through a Monte Carlo modeling approach where the last 20 years of actual weather are systematically input into the energy and peak models to produce a possible outcome distribution.

OG&E's weather-year Monte Carlo approach runs weather years 1989 to 2009 through weather-sensitive energy models, along with the peak demand model, to develop a probability distribution of possible outcomes. Figure 1 shows the 95% confidence interval around the expected energy sales forecast, including wholesale adjustments, resulting from this modeling process. Note that the decline in sales of approximately 300,000 MWh from 2011 to 2012 is principally the result of the assumption by OG&E that the current AVEC wholesale contract, which is currently set to expire on November 30th, 2011, is not renewed.

Figure 1. Energy Model Forecast Outcomes by Weather Probability



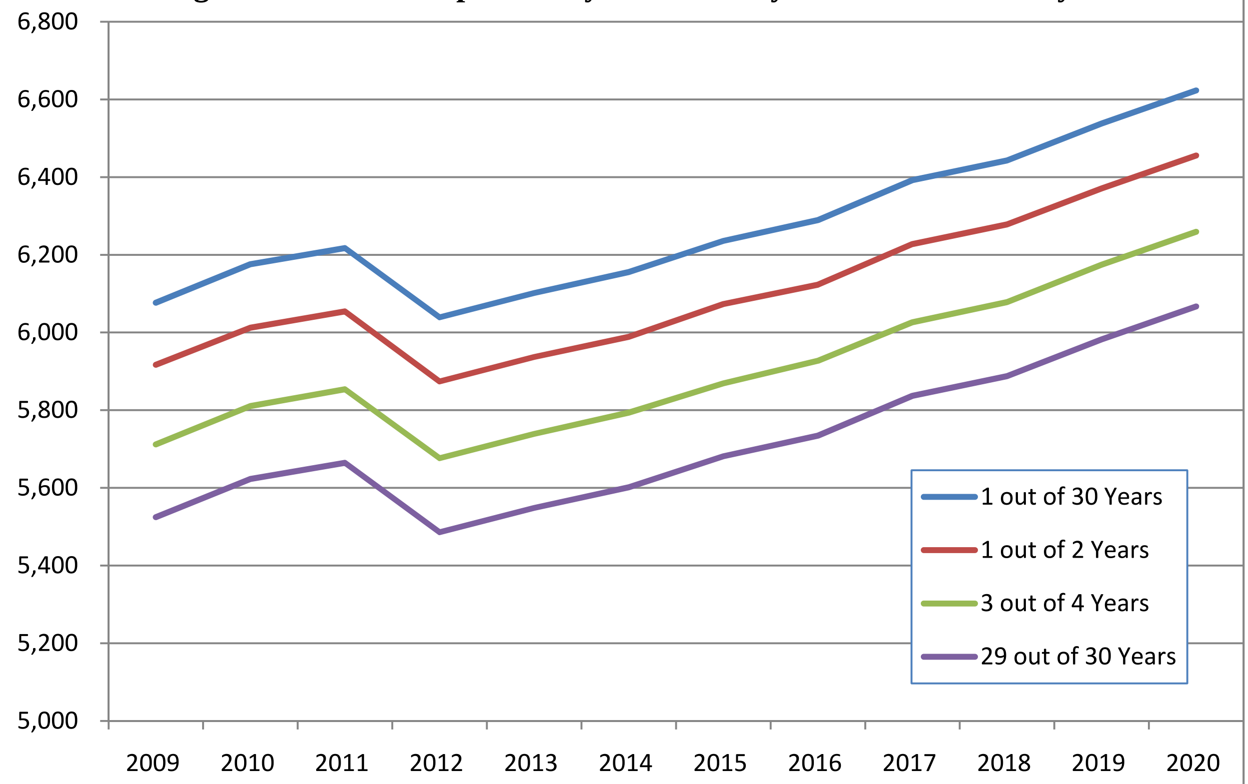
The 1 out of 2 years forecast line shows energy sales, including wholesale adjustments, assuming average weather years over the 20-year period. We note this "distribution average" is not the same as normal weather. This thinking is consistent with research findings by Chuck Doswell of the National Severe Storms Laboratory in Norman, Oklahoma. Mr. Doswell suggests: "…what is considered 'normal' may not . . . correspond precisely to the average. 'Normality' is a matter of definition. In order to understand what 'normal' means, you have to understand what was done to the data [in the normalization process]."[2]

The *1 out of 2 years* average weather line indicates there is a 50% probability that energy sales will reach this level or higher. The normal weather forecast is actually closer to the lower end of the distribution, with sales approximately 1.2% less (355,000 MWh on average per year) than the 50% probability line. Now, consider the *1 out of 30 years* forecast. This line, which is approximately 1,460,000 MWh higher than the normal weather forecast, shows energy sales under more extreme weather events occurring just 3% of the time. Finally, the lower bound forecast (*29 out of 30 year* case) shows sales may fall below the normal weather forecast by approximately 140,000 MWh if weather is milder than normal given expected economic performance.

[2] Doswell, Chuck, "Misconceptions About what is 'Normal' for the Atmosphere," 1997.

Figure 2 shows a similar graph for the load responsibility distribution. The weather modeling indicates the 95% confidence interval has a range of approximately 600 MW, with the upper bound approximately 175 MW higher than the load under expected weather conditions and a lower bound over 420 MW lower than the expected load. Again, the decline in demand of approximately 200 MW from 2011 to 2012 is principally the result of the expiration of AVEC's wholesale contract.

Figure 2. Load Responsibility Outcomes by Weather Probability



Historical Weather Normalized Retail Energy and Peak Demand

To put the forecasted retail sales and native load responsibility in perspective, we show weather normalized sales and peak demand data during the model estimation period. Figure 3 shows the retail and combined retail and wholesale forecasts of energy sales including losses as well as the weather normalized historical sales, while Figure 4 shows the weather normalized historical and forecasted native load responsibility. Both the retail energy and native load responsibility forecasts demonstrate growth similar to that in the historical model estimation period.

Figure 3. Retail and Wholesale Energy - Weather Normalized Historical and Forecast Sales

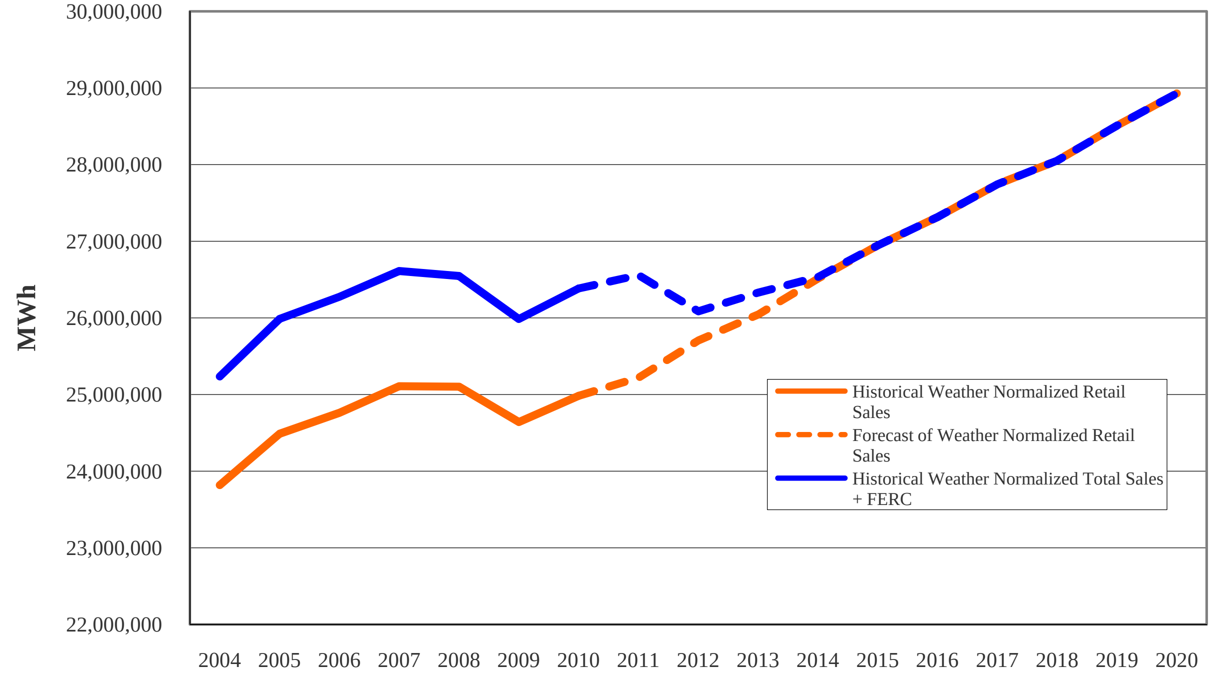
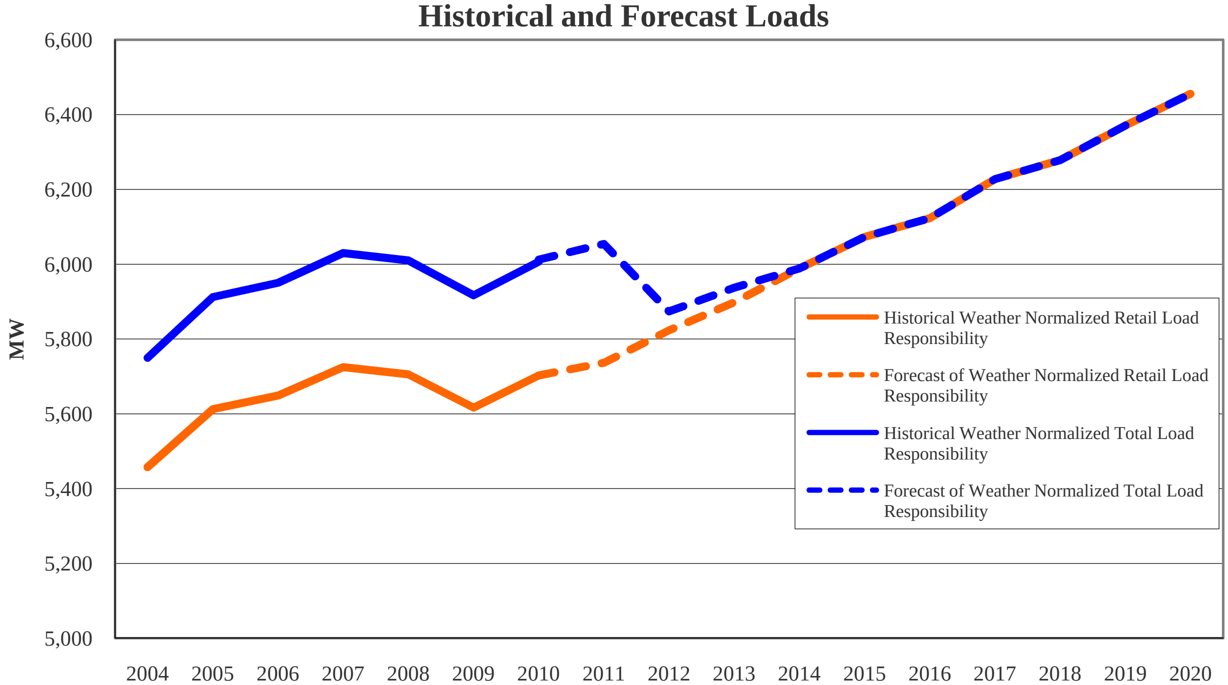


Figure 4. Native Load Responsibility - Weather Normalized Historical and Forecast Loads



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Economic Outlook

Key Takeaways:

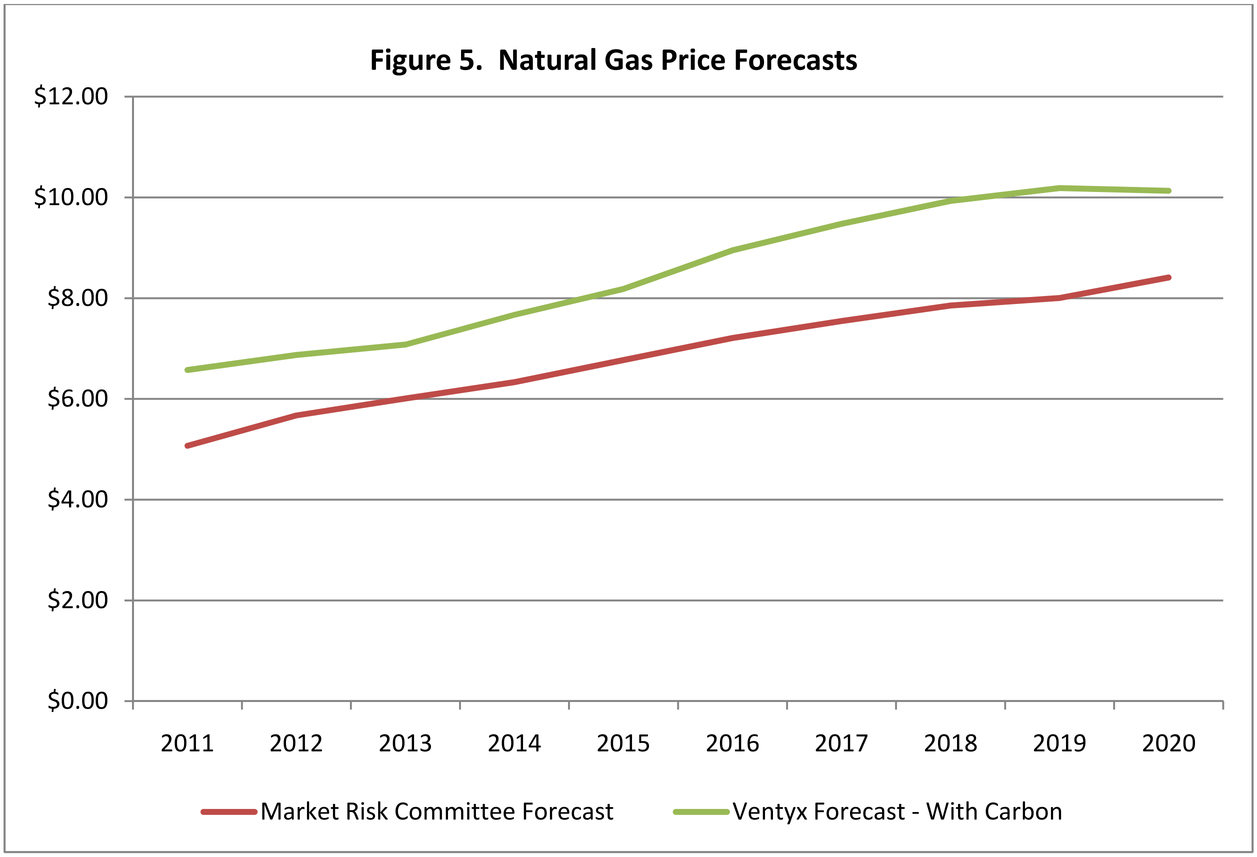
- ***The Oklahoma and Arkansas economies are showing signs of recovery, but energy prices remain a significant risk***
- ***Violence in Mexico has delayed the relocation of manufacturing operations***
- ***The development of shale plays in Oklahoma and Arkansas are vital to the economic future of Oklahoma and Arkansas***

Economic Summary

Over the last decade the Oklahoma economy has outperformed the nation due to robust growth in the energy sector. Prudent lending practices and limited direct erosion of the consumer balance sheet allowed Oklahoma to enter the recession later than the nation. The effects of the recession in Arkansas have been dampened due to the limited influence of energy prices and employers delaying plans to outsource manufacturing operations. Both states have fared better than the nation, but based on historical evidence there is no reason to believe that either state will recover before the nation.

State of Oklahoma Economic Forecast

The economic recovery in Oklahoma is expected to be modest in 2010 and 2011. Economic conditions are expected to return to more favorable conditions in 2012 and overall economic growth should be at a sustainable level. The biggest unknown factor for the Oklahoma economy is the energy sector. After experiencing considerable decline in activity in 2009, the energy sector in Oklahoma is seeing a considerable recovery in 2010. Since hitting a low of $1.84 per mmBtu on September 4th, 2009, the price of natural gas has rebounded to nearly $5 per mmBtu in 2010. This has allowed for the continued development of conventional oil and natural gas wells in the Arkoma Basin in western Oklahoma along with the shale plays in the Woodford Shale in southeast Oklahoma and the Fayetteville Shale in central Arkansas. The recovery of the energy sector in Oklahoma will play a vital role in the overall growth of the Oklahoma economy. As energy prices increase so will revenue collections for Oklahoma. Oklahoma has made efforts to diversify the economy, but the energy sector is still the foundation for the Oklahoma economy.



Oklahoma City Metropolitan Area

The Oklahoma City Metropolitan Area fared better than the rest of the state during the recession due to government employment and a limit exposure to manufacturing. The growth of Professional and Business Services in the Oklahoma City will continue to provide high paying jobs that will allow real personal income in Oklahoma City to grow faster than the state as a whole. Another major factor in the economic future of Oklahoma City is the energy sector. The only Fortune 500 companies[3] in Oklahoma City are in the Oil and Gas industry and are dependent upon favorable energy prices to continue expanding. As energy prices rebound in the coming years the Oklahoma City economy will experience sustainable growth.

Fort Smith Metropolitan Area

The future of manufacturing in the Ft. Smith Metropolitan Area is uncertain but better than previous expectations. Violence in Mexico has caused major manufacturers in Ft. Smith to cancel or postpone their plans to relocate their operations to Mexico. Similar to the Oklahoma economy, the economic recovery in Ft. Smith is expected to be modest in 2010 and 2011. Economic conditions are expected to return to sustainable levels in 2012, but a decrease in the violence in Mexico could prompt manufacturers to leave the Ft. Smith area. Further erosion of the manufacturing base in Ft. Smith would offset any economic gains during the recovery in 2010 and 2011.

[3]"Fortune 500 2010: Oklahoma" (http://money.cnn.com/magazines/fortune/fortune500/2010/states/OK.html)

Economic Drivers for Energy Forecast

The 2010 Economic Forecast calls for slowed economic growth in Oklahoma and Ft. Smith over the next five years relative to the previous decade. The economic drivers for Ft. Smith show higher growth rates over the next five years in comparison to the previous decade due to relatively poor economic conditions during the previous decade. The growth rates for 2016 to 2020 are close to the long-term expectations for each economic driver.

Table 8. Economic Drivers' Growth Rates, 2010 Forecast

Economic Drivers and Models	Average Economic Driver Annual Growth Rates		
	1999-2009	2010-2015	2016-2020
Arkansas			
Street lighting: Ft. Smith Population	0.9%	0.9%	0.8%
Residential: Real Personal Income	2.5%	2.6%	3.2%
Residential: Non-Ag Employment	0.5%	1.5%	1.2%
Commercial: Real Personal Income	2.5%	2.6%	3.2%
Commercial: Retail and Business Services Employment	0.4%	1.4%	0.6%
Public Authority: Real GMP	2.5%	2.9%	3.0%
Oklahoma			
Street Lighting: OKC Population	1.1%	1.1%	1.1%
Residential: OKC Real Personal Income*	3.6%	3.2%	3.6%
Commercial: OKC Real Personal Income*	3.6%	3.2%	3.6%
Public Authority: Real Oklahoma GSP*	1.8%	1.7%	2.4%

Load Responsibility Peak Demand Forecasting Model

Key Takeaways:

- ***Total peak load responsibility increases by an average of 0.8% per year***
- ***The expected peak load in 2020 is 6,456 MW***

This section describes the 2010 load responsibility peak demand forecasting model. The forecast follows a discussion of the basic methodology and related hourly econometric framework.

Peak Demand Forecasting Methodology

Econometric Modeling Framework

The econometric modeling framework has been in place at OG&E since 2000. The modeling structure consists of 24 separate hourly equations, one for each hour of the day, with separate intercept and slope coefficients in the various models. The hourly equations are estimated over the May through September period.

The dependent variable is OG&E's normalized load responsibility, less the fixed 25 MW Oklahoma Municipal Power Authority (OMPA) Power Sales Agreement (PSA) load, and includes line losses. Key independent variables include:

- Cooling degree hours, base 76. This cooling degree hour variable is calculated in a manner similar to cooling degree days and effectively represents temperature impacts when temperatures exceed 76 degrees.
- A second temperature variable, defined as temperature—102°, which addresses the "topping off" effect in which there is a reduction in the *rate* of load increases at very high temperatures.
- National Oceanic and Atmospheric Administration's (NOAA) misery index reflecting the combined effects of humidity and warm temperatures. The misery build-up or duration of the misery index is captured through the weighted average of past hourly values of the misery index.[4]
- Wind speed.
- School end date in May and start-up in August.
- Economic growth as reflected through weather-adjusted retail energy sales, where weather is effectively removed from the energy series such that the resulting retail total represents the aggregate impact of economic conditions on the OG&E system. The sales are also normalized by the number of days in each month.

Other variables in the hourly models include binary (dummy) variables representing different days of the week and different months within the year, which interact with the weather variables in most of the hourly equations.

Relevant weather stations are shown below in Table 9, along with the OG&E population estimates from the 2000 census used to weigh data from each station:

Table 9. Weather Station Weights

Weather Station	Population in OG&E Territory	Weight (% of OG&E population)
Oklahoma City (Will Rogers)	1,215,619	63.4%
Fort Smith	285,644	14.9%
Guthrie	154,327	8.0%
Stillwater	153,029	8.0%
Muskogee	109,834	5.7%

[4] The lag structure is designed to pick up the effects of a heat wave lasting a few days or more. More electricity is demanded later (vs. earlier) in a heat wave, even when temperatures decline slightly. The implication is that "design temperature" is not sufficient for peak forecasting purposes. The temperature of the building is the result of the accumulated outdoor temperatures, less the impact of the HVAC system. The weighted average is capable of capturing the effects of both duration and nighttime cooling since high daytime temperatures and lower nighttime temperatures are reflected in the average.

Forecasting Peak Loads

The peak demand forecast is generated via a probabilistic approach by using the last 20 available years of weather data, rather than a single year or an average of weather years. This Monte Carlo approach essentially runs all weather years from 1989 to 2009 through the peak demand model, while alternating the weather year "starting day" seven times, so extreme weekday (weekend) weather event probability is treated directly in the simulations. For example, the most extreme heat wave in the past might have begun on a Thursday and topped out on a Sunday. Since loads are much lower on weekends, the heat wave would not have led to a system peak for the year. However, the extreme weather did occur and might indeed have led to a peak event if it began on a Monday and ended on a Thursday. This is why the starting day for historical weather from past years must be translated into seven distinct possible outcomes.

This results in a matrix of 20 weather years by seven days, or a total of 140 simulations given the historical hourly weather data available to OG&E.

The process for constructing the peak demand forecast is as follows:

- Obtain a range of weather-feasible load forecasts for each year over the forecast horizon (2010–2020) by multiplying the regression model coefficients by the corresponding values of weather-related variables. As described above, this step generates 140 weather-feasible forecasts.
- Rank order these 140 annual load forecasts from highest to lowest, and assign probabilities to the occurrence of each forecast under the assumption of a uniform distribution (i.e., each weather has an equal chance of occurrence).

All of the highest values (peaks) in the resulting forecast distribution occur between 3:00 p.m. and 7:00 p.m. (Central Daylight Time), with the majority occurring at 5:00 p.m.

Table 10 illustrates mapping between event occurrence and the occurrence probability. The median load projections come from the 50th percentile of the distribution. This means that half of the time, the peak load would be expected to exceed this level; and half of the time, the peak load would be below this level. In other words we would expect to hit this level at least once over a two-year period, so we call this the *1 out of 2 year* case.

Table 10. Probability Assignments

Event Occurrence	Occurrence Probability
1 out of 30 years	3%
1 out of 10 years	10%
1 out of 4 years	25%
1 out of 2 years	50%
3 out of 4 years	75%
9 out of 10 years	90%
29 out of 30 years	97%

Consider now the 10th percentile of the distribution. There is a 10% chance loads will be at this level or higher in any future year, which we interpret as a *1 out of 10 year* event. On the other side of the distribution, consider row 126 out of 140 (or the 90th percentile). There is a 90% chance loads will be at this level or higher in any future year, which we interpret as a *9 out of 10 year* event.

Expected Loads by Weather Probability

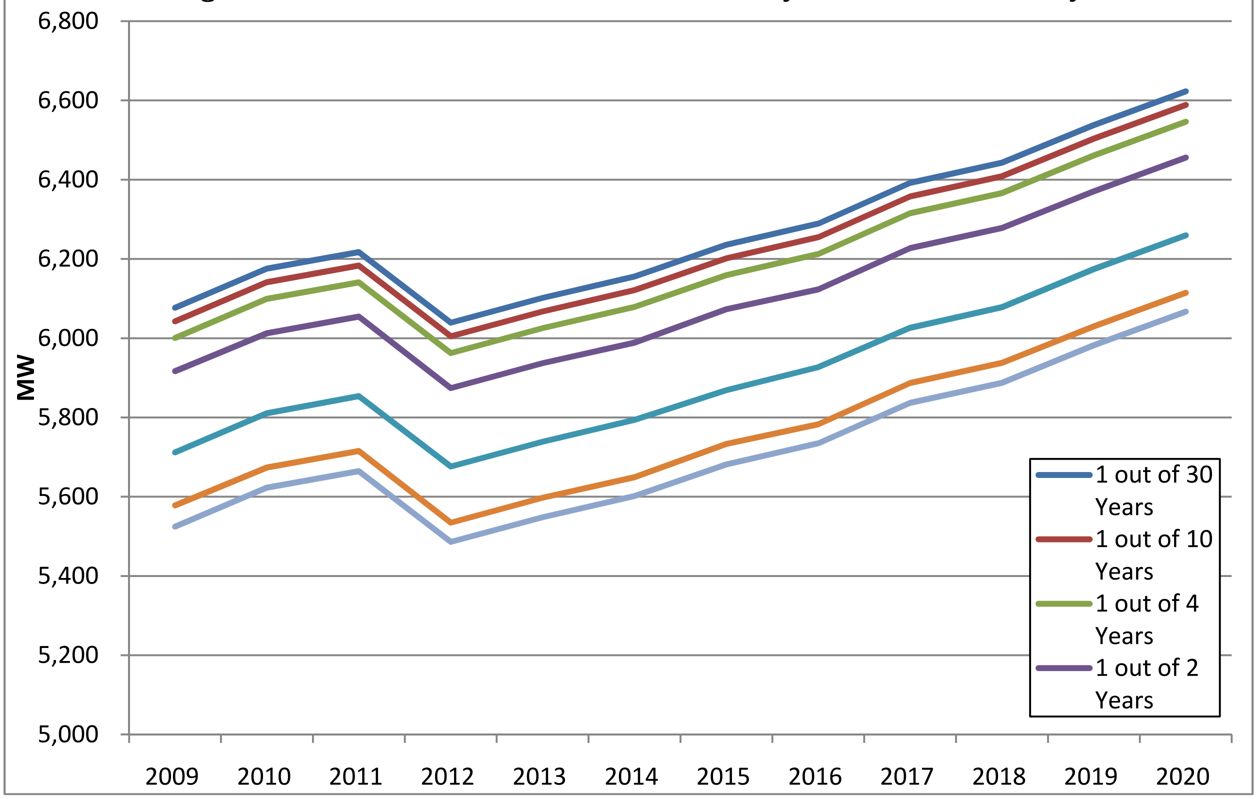
Table 11 and Figure 6 summarize the peak load model forecasts with a 95% confidence interval around potential weather events, assuming no changes in the expected economic outlook. These estimates include wholesale loads and the assumption of expiring wholesale contracts. Following the probability assignments in Table 10, the interpretation of these results is as follows. The *1 out of 2 years* or "expected" forecast shows the peak demand level given the 50th percentile of the load forecast distribution, using all available historical weather data. In this case, there is a 50% probability the peak load will reach this load level or higher.

Considering the 1 out of 10 years forecast, which is approximately 130 MW higher than the *1 out of 2 years* case, shows the estimated peak demand under a more extreme weather event that occurs just 10% of the time. Put differently, over a 10-year planning horizon, it is likely that OG&E will hit a summer peak consistent with the *1 out of 10 years* forecast at least once. The key area of uncertainty is in *which* year this event will occur.

Table 11. Peak Demand Model Forecasts by Weather Probability

Year	1 out of 30 Years	1 out of 10 Years	1 out of 4 Years	1 out of 2 Years	3 out of 4 Years	9 out of 10 Years	29 out of 30 Years
2010	6,176	6,142	6,099	6,012	5,811	5,674	5,623
2011	6,217	6,183	6,141	6,054	5,854	5,715	5,665
2012	6,039	6,005	5,963	5,874	5,676	5,535	5,486
2013	6,102	6,068	6,025	5,937	5,739	5,597	5,548
2014	6,156	6,121	6,079	5,989	5,794	5,649	5,601
2015	6,236	6,201	6,159	6,073	5,869	5,733	5,681
2016	6,289	6,255	6,213	6,123	5,927	5,783	5,735
2017	6,392	6,358	6,315	6,228	6,026	5,887	5,837
2018	6,443	6,409	6,366	6,278	6,078	5,938	5,887
2019	6,538	6,504	6,461	6,371	6,175	6,030	5,982
2020	6,623	6,589	6,546	6,456	6,259	6,115	6,067

Figure 6. Peak Demand Model Forecasts by Weather Probability



It is possible—even likely— that weather conditions will vary markedly from one year to the next. For example, the weather-year forecast simulations reveal 2004 weather was the fourth coolest of the 20 weather years, 2007 was in the middle of the range, and 2006 weather was the fourth hottest. Dramatic weather condition changes, not economic growth, are responsible for year-to-year differences. Overall, the 95% confidence interval associated with weather conditions represents a significant source of risk responsible for approximately 630 MW of potential peak load variability.

FERC Wholesale Load Adjustments

FERC wholesale load adjustments are conducted in two steps based on known and verifiable events. First, the OMPA wholesale load Power Sales Agreement (PSA) contract is added to the normalized load responsibility forecast from the model. Second, expiring contracts are subtracted to obtain final 2010 Load Responsibility forecasts. Table 12 includes the expected dates that all existing wholesale sales contracts will end assuming customers find alternate suppliers.

Table 12. 2010 Load Responsibility Forecast

Demand (MW)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
FERC Load (without losses)												
MUNICIPAL[12]	11.4	6.7	8.8	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COOPERATIVE[13]	201.8	216.4	221.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SPA[14]	18.0	17.2	17.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OMPA PSA[15]	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MDEA[16]	20.0	20.0	20.0	20.0	10.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total FERC Load (w/o losses)	**276.2**	**285.3**	**292.5**	**46.6**	**35.7**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Losses (Loss factor = 0.0867)	23.9	24.7	25.4	4.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total FERC Load (losses added)	**300.1**	**310.0**	**317.9**	**50.7**	**38.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Percentage Change in Total FERC Load		3.3%	2.6%	-84.1%	-23.5%	-100.0%	0.7%	0.7%	0.7%	0.7%	0.7%	-100.0%
Total Retail Load (with losses)	5,617	5,702	5,736	5,823	5,898	5,989	6,073	6,123	6,228	6,278	6,371	6,456
Percentage Change in Total Retail Load		1.5%	0.6%	1.5%	1.3%	1.5%	1.4%	0.8%	1.7%	0.8%	1.5%	1.3%
Load Responsibility (with losses)												
Load Responsibility = Total Retail Load + FERC, Losses Added (includes curtailable load)*	**5,917**	**6,012**	**6,054**	**5,874**	**5,937**	**5,989**	**6,073**	**6,123**	**6,228**	**6,278**	**6,371**	**6,456**
Percentage Change in Load Responsibility		1.6%	0.7%	-3.0%	1.1%	0.9%	1.4%	0.8%	1.7%	0.8%	1.5%	1.3%
Load Factor												
Load Responsibility = Total Retail Load + FERC, Losses Added*	**5,917**	**6,012**	**6,054**	**5,874**	**5,937**	**5,989**	**6,073**	**6,123**	**6,228**	**6,278**	**6,371**	**6,456**
Total Retail Sales + FERC, Losses Added	27,800,572	28,228,196	28,413,888	27,908,465	28,169,061	28,387,249	28,828,465	29,224,415	29,681,602	30,013,134	30,501,277	30,949,656
Load Factor	53.64%	53.60%	53.57%	54.24%	54.16%	54.11%	54.19%	54.48%	54.41%	54.57%	54.65%	54.73%

[12] Watonga contract can expire on February 28, 2012, Paris contract can expire on May 31, 2012, Orlando contract can expire on October 31, 2012 and the Geary contract expired on April 30, 2010

[13] AVEC contract can expire on November 30, 2011

[14] Paris contract can expire on May 31, 2012 and Vance contract can expire on May 31, 2012

[15] OMPA PSA contract terminates on December 31, 2013 and is removed from the forecast at that time due to the absence of an Evergreen clause in the contract

[16] MDEA contract 2 can expire on December 31, 2012 and MDEA contract 1 can expire on April 30, 2014

Retail Energy Models

This section describes the methodology and results associated with sales equations estimates by state and revenue class.

Key Takeaways:

- ***Total retail energy increases by an average of 1.47% per year***
- ***Total retail energy for 2020 is expected to be 28,927,616 MWh***

Econometric Modeling Process

The monthly energy consumption analysis for each market segment follows a four-step process:

Step 1. Review 2009 forecast results to determine which segments require the most attention to alternative model specifications and visual inspection of each sales series to identify sudden changes in usage that might require dummy variables.

Step 2. Generate initial estimates using 2009 model specification.

Step 3. Inspect goodness-of-fit and other important statistics (e.g., R-squared, t-statistics, multicollinearity statistics); visual inspection of actual versus predicted values of the dependent variable over the historical period.

Step 4. Repeat steps 1 through 3 as needed until a final specification is generated.

Between 10 and 50 models were estimated for each segment. The final model was not always the one with the "best fit." The overriding selection criterion was the model providing the best forecast. For example, if a model with an R-square of 0.95 had a larger error in the out-of-sample period than an alternative model with an R-square of 0.93, the latter model was selected. Table 13 and Table 14 illustrate the final model variables used for Oklahoma and Arkansas, respectively.

Table 13. Oklahoma Energy Model Drivers, 2010

	Economic Drivers Oklahoma Economic Outlook	Other Drivers
Residential	OKC Real Personal Income^	Real Residential electric price, Heating-Degree Days (HDD), Cooling-Degree Days (CDD)
Commercial	OKC Real Personal Income^	Real Commercial electric price, HDD, CDD
Public Authority	Real GSP^	Real Public Authority electric price, HDD, CDD
Street lighting	OKC Population	Free Street Lighting Service Variable

* Some models also have monthly-specific intercept and interaction terms.

^ Adjusted using definitions from OSU

Table 14. Arkansas Energy Model Drivers, 2010

	Economic Drivers Oklahoma Economic Outlook	Other Drivers
Residential	Ft. Smith Real Personal Income	Real Residential electric price, HDD, CDD
Commercial	Ft. Smith Real Personal Income, Ft. Smith Retail and Business Services Employment	Real Commercial electric price, HDD, CDD
Public Authority	Real GSP	Real Public Authority electric price, HDD, CDD
Street lighting	Ft. Smith Population	

* Some models also have monthly-specific intercept and interaction terms.

2010 Energy Forecast

Retail Forecast

Table 15 summarizes the 2010 retail energy forecast (excluding line losses) by state and for the company as a whole. Weather-normalized annual retail sales are expected to grow from 24,640 GWh in 2009 to 28,927 GWh in 2020, which translates into a 17.4% increase over OG&E's planning horizon, or an average annual increase of 1.47%.

Projected growth rates associated with these data are comparable to those observed over the last decade. Weather-normalized sales grew by approximately 1.8% annually from 1997 through 2007. Average annual growth is projected to be lower from 2010 to 2014 (1.47%), consistent with economic growth rates noted in the *Economic Outlook* section of this report. Average annual sales growth in the last half of the forecast, the 2015–2020 period, will be higher (1.46%), again consistent with economic driver growth rate projections.

FERC Wholesale Load Adjustments

In 2010 OG&E and Cadmus were jointly responsible for producing the forecasts of FERC wholesale sales. OG&E provided Cadmus with historical wholesale sales data and the expiration dates for current FERC wholesale contracts. Using an econometric forecasting approach similar to what was used for the retail energy forecast models, Cadmus produced separate forecasts of wholesale sales for all of the wholesale contracts. Out of model adjustments were then made to those forecasts to remove sales of expiring contracts from the overall wholesale forecast. Table 16 combines the forecasts of wholesale sales with the retail energy forecast from Table 15, yielding the final 2010 total energy sales forecast.

Table 15. 2010 Retail Energy Forecast (MWh)

	Year	Residential	Commercial	Public Authority	Street lighting	Industrial	Petroleum	Total
Arkansas	2009	722,794	715,816	135,578	8,891	981,796	10,304	2,575,178
	2010	729,347	725,335	143,298	8,956	1,099,760	10,819	2,717,515
	2011	733,282	747,491	151,308	9,003	1,105,259	10,873	2,757,216
	2012	755,490	781,209	157,087	9,058	1,110,785	10,927	2,824,556
	2013	770,757	802,772	162,693	9,116	1,116,339	10,982	2,872,660
	2014	788,664	828,890	168,031	9,176	1,121,921	11,037	2,927,719
	2015	806,894	855,544	173,834	9,236	1,127,531	11,092	2,984,130
	2016	823,659	881,711	180,484	9,295	1,133,168	11,148	3,039,464
	2017	840,466	907,350	187,948	9,353	1,138,834	11,203	3,095,154
	2018	856,214	931,770	195,692	9,410	1,144,528	11,259	3,148,874
	2019	872,521	960,657	203,729	9,466	1,150,251	11,316	3,207,940
	2020	890,534	994,432	212,714	9,522	1,156,002	11,372	3,274,576
Oklahoma	2009	8,060,751	5,727,776	2,735,363	53,892	2,574,462	2,913,067	22,065,310
	2010	8,157,927	5,794,732	2,742,487	54,950	2,587,334	2,927,633	22,265,063
	2011	8,219,551	5,841,987	2,801,885	55,718	2,600,271	2,942,271	22,461,683
	2012	8,367,433	6,010,762	2,874,937	56,483	2,613,272	2,956,982	22,879,870
	2013	8,483,288	6,118,123	2,914,718	57,258	2,626,339	2,971,767	23,171,493
	2014	8,681,224	6,252,563	2,965,126	58,046	2,639,470	2,986,626	23,583,055
	2015	8,808,362	6,409,518	3,029,932	58,841	2,652,668	3,001,559	23,960,879
	2016	8,906,022	6,534,393	3,093,069	59,644	2,665,931	3,016,567	24,275,626
	2017	9,010,788	6,691,919	3,173,185	60,452	2,679,261	3,031,650	24,647,254
	2018	9,058,135	6,802,889	3,241,648	61,269	2,692,657	3,046,808	24,903,406
	2019	9,184,894	6,959,772	3,325,669	62,093	2,706,120	3,062,042	25,300,590
	2020	9,290,742	7,103,290	3,399,081	62,925	2,719,651	3,077,352	25,653,040
Total OG&E	2009	8,783,545	6,443,591	2,870,941	62,783	3,556,258	2,923,371	24,640,489
	2010	8,887,273	6,520,068	2,885,784	63,907	3,687,094	2,938,452	24,982,578
	2011	8,952,833	6,589,478	2,953,193	64,721	3,705,530	2,953,144	25,218,899
	2012	9,122,924	6,791,970	3,032,024	65,541	3,724,058	2,967,910	25,704,426
	2013	9,254,045	6,920,895	3,077,411	66,374	3,742,678	2,982,749	26,044,153
	2014	9,469,888	7,081,453	3,133,157	67,222	3,761,391	2,997,663	26,510,774
	2015	9,615,256	7,265,062	3,203,766	68,076	3,780,198	3,012,651	26,945,009
	2016	9,729,681	7,416,105	3,273,553	68,938	3,799,099	3,027,714	27,315,090
	2017	9,851,253	7,599,269	3,361,133	69,805	3,818,095	3,042,853	27,742,408
	2018	9,914,349	7,734,659	3,437,341	70,678	3,837,185	3,058,067	28,052,280
	2019	10,057,415	7,920,430	3,529,398	71,559	3,856,371	3,073,358	28,508,530
	2020	10,181,275	8,097,721	3,611,795	72,447	3,875,653	3,088,724	28,927,616

Table 16. Energy Forecast Accounting for Changes in Wholesale Load

Energy (MWH)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
FERC Sales (without losses)												
MUNICIPAL[17]	40,183	35,505	32,511	6,562	0	0	0	0	0	0	0	0
AVEC[18]	896,336	947,936	886,737	0	0	0	0	0	0	0	0	0
SPA[19]	71,232	76,298	77,731	32,487	0	0	0	0	0	0	0	0
OMPA[20]	210,182	219,000	219,000	219,000	219,000	0	0	0	0	0	0	0
MDEA[21]	125,849	122,640	122,640	122,640	65,533	21,844	0	0	0	0	0	0
Total FERC Sales	1,343,783	1,401,380	1,338,619	380,689	284,533	21,844	0	0	0	0	0	0
Growth Rate in FERC sales		4.3%	-4.5%	-71.6%	-25.3%	-92.3%	-100.0%	0.5%	0.0%	0.0%	0.0%	0.0%
Retail Sales (without losses)												
Residential	8,783,545	8,887,273	8,952,833	9,122,924	9,254,045	9,469,888	9,615,256	9,729,681	9,851,253	9,914,349	10,057,415	10,181,275
Commercial	6,443,591	6,520,068	6,589,478	6,791,970	6,920,895	7,081,453	7,265,062	7,416,105	7,599,269	7,734,659	7,920,430	8,097,721
Industrial	3,556,258	3,687,094	3,705,530	3,724,058	3,742,678	3,761,391	3,780,198	3,799,099	3,818,095	3,837,185	3,856,371	3,875,653
Industrial Petroleum	2,923,371	2,938,452	2,953,144	2,967,910	2,982,749	2,997,663	3,012,651	3,027,714	3,042,853	3,058,067	3,073,358	3,088,724
Total Industrial	6,479,629	6,625,546	6,658,674	6,691,967	6,725,427	6,759,054	6,792,849	6,826,814	6,860,948	6,895,252	6,929,729	6,964,377
Public Authority and Street Lighting	2,933,724	2,949,691	3,017,914	3,097,565	3,143,785	3,200,379	3,271,842	3,342,491	3,430,938	3,508,019	3,600,956	3,684,242
Total Retail Sales	**24,640,489**	**24,982,578**	**25,218,899**	**25,704,426**	**26,044,153**	**26,510,774**	**26,945,009**	**27,315,090**	**27,742,408**	**28,052,280**	**28,508,530**	**28,927,616**
Growth Rate in Retail Sales		1.4%	0.9%	1.9%	1.3%	1.8%	1.6%	1.4%	1.6%	1.1%	1.6%	1.5%
Total MWH Sales (with losses)												
Total Retail Sales + FERC	25,984,271	26,383,958	26,557,518	26,085,115	26,328,686	26,532,619	26,945,009	27,315,090	27,742,408	28,052,280	28,508,530	28,927,616
Losses[22]	1,816,301	1,844,239	1,856,370	1,823,350	1,840,375	1,854,630	1,883,456	1,909,325	1,939,194	1,960,854	1,992,746	2,022,040
Total Retail Sales + FERC, Losses Added	**27,800,572**	**28,228,196**	**28,413,888**	**27,908,465**	**28,169,061**	**28,387,249**	**28,828,465**	**29,224,415**	**29,681,602**	**30,013,134**	**30,501,277**	**30,949,656**
Growth Rate in Total Sales		1.5%	0.7%	-1.8%	0.9%	0.8%	1.6%	1.4%	1.6%	1.1%	1.6%	1.5%

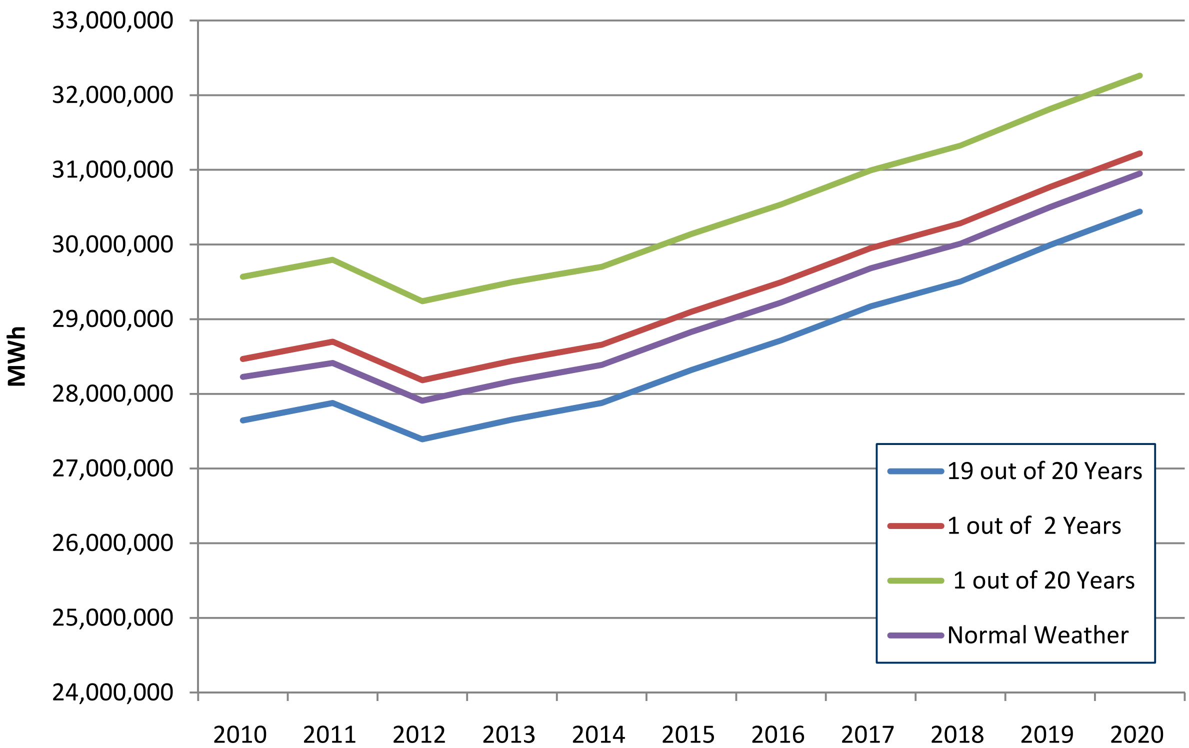
[17] Watonga contract can expire on February 28, 2012, Paris Contract can expire on May 31, 2012, Orlando contract can expire on October 31, 2012 and the Geary contract expired on April 30, 2010
[18] AVEC contract can expire on November 30, 2011
[19] Paris contract can expire on May 31, 2012 and Vance contract can expire on May 31, 2012
[20] OMPA PSA contract terminates on December 31, 2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.
[21] MDEA contract 2 can expire on December 31, 2013 and MDEA contract 1 can expire on April 30, 2014
[22] The energy loss factor is 0.0699 for 2009 and beyond

Energy Forecast Uncertainty

As with the load responsibility peak demand forecast, weather uncertainty in the energy models is represented through a Monte Carlo modeling approach where the last three decades of weather are systematically inputted into the various energy models to produce a distribution of possible sales outcomes.

The weather-year Monte Carlo approach essentially runs all weather years from 1989 to 2009 through the weather-sensitive energy models and the peak demand model to develop a probability distribution of possible outcomes. Figure 7 shows the results directly from this modeling process for energy sales and includes FERC adjustments.

Figure 7. Energy Model Forecast Outcomes by Weather Probability



The *1 out of 2 years* average weather line indicates there is a 50% probability that energy sales will reach this level or higher. The normal weather forecast is actually closer to the lower end of the distribution, with sales approximately 1.2% less (355,000 MWh on average per year) the 50% probability line.

Now, consider the *1 out of 30 years* forecast. This line, which is approximately 1,460,000 MWh higher than the normal weather forecast, shows energy sales under more extreme weather events occurring just 3% of the time. Finally, the lower bound forecast (*29 out of 30 year* case) shows sales may fall below the normal weather forecast by approximately 140,000 MWh if weather is milder than normal given expected economic performance.

Retail Customer Forecasting Models

This section describes the methodology and results associated with state and revenue class customer forecasting. These models were first estimated in 2005 and follow the general approach for energy sales outlined in this report's previous section.

Key Takeaways:

- ***Total retail customers increases by an average of 1% per year***
- ***The forecasted total number of retail customers in 2020 is 863,022***

Retail Customer Modeling Process and Forecast

Approximately five to ten models were estimated for each segment, with 2009 data held as an "out-of-sample" forecasting test period. During the initial model specification phase, attempts were made at specifying models with a variety of different economic drivers. Table 17 and Table 18 illustrate the final model variables used for the Oklahoma and Arkansas retail customer forecasts, respectively.

Table 17. Oklahoma Customer Model Drivers, 2010

	Economic Drivers Oklahoma Economic Outlook
Residential	Population of Oklahoma City
Commercial	Population of Oklahoma City
Industrial	Employment in the Oklahoma City Manufacturing Sector
Petroleum	Stepped Nominal Natural Gas Price Forecast
Public Authority	Population of Oklahoma City
Street lighting	Population of Oklahoma City and Free Street Lighting Service Variable

Table 18. Arkansas Customer Model Drivers, 2010

	Economic Drivers Oklahoma Economic Outlook
Residential	Population of Ft. Smith
Commercial	Population of Ft. Smith
Industrial	Employment in the Ft. Smith Manufacturing Sector
Petroleum	Stepped Nominal Natural Gas Price Forecast
Public Authority	Population of Ft. Smith
Street lighting	Population of Ft. Smith

Table 19 summarizes the 2010 annual retail customer forecast by sector and state, and for the company as a whole.

Table 19. 2010 Retail Customer Forecast

Region	Year	Residential	Commercial	Public Authority	Street Lighting	Industrial	Petroleum	Total
Arkansas	2009	53,965	8,732	1,435	26	382	55	64,595
	2010	54,130	8,844	1,462	26	367	57	64,886
	2011	54,295	8,959	1,497	27	368	58	65,203
	2012	54,524	9,067	1,532	27	372	59	65,580
	2013	54,801	9,183	1,568	27	375	59	66,013
	2014	55,100	9,302	1,604	27	377	59	66,469
	2015	55,405	9,419	1,641	27	378	59	66,930
	2016	55,712	9,536	1,679	27	378	59	67,391
	2017	56,017	9,650	1,718	28	378	59	67,848
	2018	56,319	9,762	1,757	28	378	59	68,303
	2019	56,618	9,873	1,797	28	378	59	68,754
	2020	56,916	9,984	1,838	28	378	59	69,203
Oklahoma	2009	609,127	76,666	14,292	224	2,685	6,367	709,361
	2010	614,905	77,620	14,634	225	2,693	6,349	716,425
	2011	621,548	78,639	15,021	226	2,705	6,304	724,444
	2012	627,811	79,487	15,396	227	2,709	6,262	731,892
	2013	634,082	80,336	15,776	228	2,708	6,231	739,361
	2014	640,428	81,199	16,161	228	2,704	6,212	746,933
	2015	646,819	82,071	16,551	229	2,699	6,204	754,573
	2016	653,269	82,950	16,944	230	2,694	6,200	762,287
	2017	659,761	83,836	17,340	231	2,689	6,200	770,057
	2018	666,319	84,731	17,741	231	2,684	6,200	777,906
	2019	672,933	85,634	18,144	232	2,679	6,201	785,824
	2020	679,614	86,546	18,552	233	2,674	6,201	793,819
Total OG&E	2009	663,092	85,398	15,727	250	3,067	6,422	773,956
	2010	669,035	86,464	16,095	252	3,059	6,406	781,311
	2011	675,844	87,598	16,518	253	3,073	6,362	789,647
	2012	682,335	88,554	16,928	254	3,081	6,321	797,472
	2013	688,883	89,519	17,343	255	3,083	6,290	805,373
	2014	695,528	90,501	17,766	255	3,081	6,271	813,402
	2015	702,225	91,490	18,192	256	3,077	6,262	821,503
	2016	708,981	92,486	18,624	257	3,072	6,258	829,678
	2017	715,777	93,486	19,058	258	3,067	6,259	837,905
	2018	722,637	94,494	19,498	259	3,062	6,259	846,209
	2019	729,551	95,508	19,941	260	3,057	6,260	854,578
	2020	736,529	96,530	20,390	261	3,052	6,259	863,022

Data Sources

OG&E's service territory encompasses approximately half of Oklahoma and a small area in western Arkansas, including and surrounding Ft. Smith. Historical data sources used to estimate the econometric equations and prepare the 2009 forecast are divided into the following categories:

- OG&E company data (energy sales, revenue, and load responsibility peak demand);
- Constructed variables for the models (usually binary variables);
- Weather information; and
- Economic and demographic data from the Center for Applied Economic Research at Oklahoma State University

This section describes each of these categories and the types of variables used in the econometric models.

Internal Information

Sales and Prices

OG&E's Accounting Department provides sales (MWh), revenue, and customer data by revenue class. This information is recorded in the monthly energy sales report for both Oklahoma and Arkansas jurisdictions. The monthly energy sales report contains information from the 1970s to the present. The six revenue classes are:

- Residential
- Commercial
- Industrial
- Industrial-Petroleum
- Public Authority
- Street Lighting

Monthly residential, commercial, industrial, industrial-petroleum, public authority, and street lighting sales data are modeled separately by state. In the econometric models with statistically significant electric price variables, these variables are defined as "average" prices (energy revenues divided by energy sales).

Load Responsibility

The peak load forecasts are obtained based on historical "Normalized Load Responsibility" data (defined as the System Load minus OMPA Total Load plus OMPA PSA[5] plus Load Curtailment plus real-time pricing (RTP) induced self-generation). The normalized load responsibility series was further adjusted for peak demand modeling purposes by subtracting variable OMPA PSA loads and forecasting these directly as wholesale FERC loads.

[3] OMPA PSA contract terminates 12/31/2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.

Information Obtained from External Sources

Weather Data

OG&E obtained the following information from the Department of Commerce, NOAA:

- Cooling-degree days (CDD).
- Heating-degree days (HDD).
- A variety of hourly weather indicators, including temperature, humidity, dew point, precipitation, wind speed, and cloud cover.

NOAA's definition of HDD is 65° minus the average of the high and low temperatures of the day (or zero if the average of the high and low temperatures is greater than 65°). The definition of CDD is the average of the high and low temperatures of the day minus 65° (or zero if the average of the high and low temperatures of the day is less than 65°). HDD and CDD for Ft. Smith and Oklahoma City have been used in weather-sensitive sales forecasting equations. Hourly weather data from these stations, and from Guthrie, Stillwater, and Muskogee, were used to model and forecast peak loads.

Economic and Demographic Data

OG&E purchases economic and demographic data from Oklahoma State University. The data include historical and forecasted time series used in the econometric models; these data include population, real income, wages and salaries, price deflators, various production and output series, including industrial production, gross state product, natural gas prices, and employment.

Appendix

Carbon Scenario Tables

Table 3b. 2010 Retail and Wholesale Energy Sales Forecasts with Carbon

Year	Energy Forecast (MWh) Including Wholesale Sales and Line Losses	Energy Growth Rates Including Wholesale Sales and Line Losses	Retail Energy Forecast (MWh)	Retail Energy Growth Rates
2009	27,800,572		24,640,489	
2010	28,228,196	1.54%	24,982,578	1.39%
2011	28,413,888	0.66%	25,218,899	0.95%
2012	27,775,312	-2.25%	25,579,973	1.43%
2013	27,935,414	0.58%	25,825,770	0.96%
2014	28,003,275	0.24%	26,151,887	1.26%
2015	28,379,067	1.34%	26,524,972	1.43%
2016	28,712,321	1.17%	26,836,453	1.17%
2017	29,129,122	1.45%	27,226,023	1.45%
2018	29,426,641	1.02%	27,504,105	1.02%
2019	29,880,548	1.54%	27,928,356	1.54%
2020	30,328,332	1.50%	28,346,884	1.50%

Table 4b. 2010 Oklahoma Retail Sales Forecast Growth Rates by Sector with Carbon

Year	Residential	Commercial	Public Authority	Street Lighting	Industrial	Petroleum
2010	1.21%	1.17%	0.26%	1.96%	0.50%	0.50%
2011	0.76%	0.82%	2.17%	1.40%	0.50%	0.50%
2012	1.32%	1.89%	1.94%	1.37%	0.50%	0.50%
2013	0.29%	1.79%	1.39%	1.37%	0.50%	0.50%
2014	0.97%	1.95%	1.56%	1.38%	0.50%	0.50%
2015	0.99%	2.36%	2.08%	1.37%	0.50%	0.50%
2016	0.55%	1.89%	2.05%	1.36%	0.50%	0.50%
2017	0.85%	2.38%	2.57%	1.36%	0.50%	0.50%
2018	0.28%	1.59%	2.12%	1.35%	0.50%	0.50%
2019	1.19%	2.26%	2.56%	1.34%	0.50%	0.50%
2020	1.11%	2.18%	2.29%	1.34%	0.50%	0.50%

Table 5b. 2010 Arkansas Retail Sales Forecast Growth Rates by Sector with Carbon

Year	Residential	Commercial	Public Authority	Street lighting	Industrial	Petroleum
2010	0.91%	1.33%	5.69%	0.73%	12.02%	5.00%
2011	0.54%	3.05%	5.59%	0.52%	0.50%	0.50%
2012	2.56%	3.96%	3.65%	0.60%	0.50%	0.50%
2013	1.95%	2.68%	3.54%	0.65%	0.50%	0.50%
2014	2.22%	3.14%	3.25%	0.66%	0.50%	0.50%
2015	2.20%	3.09%	3.42%	0.65%	0.50%	0.50%
2016	2.05%	3.03%	3.82%	0.64%	0.50%	0.50%
2017	2.02%	2.89%	4.13%	0.62%	0.50%	0.50%
2018	1.84%	2.66%	4.11%	0.61%	0.50%	0.50%
2019	1.87%	3.08%	4.10%	0.60%	0.50%	0.50%
2020	2.12%	3.59%	4.44%	0.59%	0.50%	0.50%

Table 7b. 2010 Load Responsibility Peak Demand Forecast with Carbon

Year	Total Load Responsibility Peak Demand (MW) Forecast* (Average Weather)	Total Load Responsibility Growth Rates	Retail Load Responsibility Peak Demand (MW) Forecast (Average Weather)	Retail Load Responsibility Growth Rates
2009	5,917		5,617	
2010	6,012	1.61%	5,702	1.52%
2011	6,056	0.73%	5,738	0.63%
2012	5,848	-3.43%	5,797	1.04%
2013	5,896	0.81%	5,857	1.03%
2014	5,918	0.38%	5,918	1.04%
2015	5,993	1.27%	5,993	1.27%
2016	6,031	0.64%	6,031	0.64%
2017	6,129	1.62%	6,129	1.62%
2018	6,174	0.73%	6,174	0.73%
2019	6,260	1.40%	6,260	1.40%
2020	6,338	1.25%	6,338	1.25%

Table 11b. Peak Demand Model Forecasts by Weather Probability with Carbon

Year	1 out of 30 Years	1 out of 10 Years	1 out of 4 Years	1 out of 2 Years	3 out of 4 Years	9 out of 10 Years	29 out of 30 Years
2010	6,176	6,142	6,099	6,012	5,811	5,673	5,623
2011	6,217	6,183	6,141	6,056	5,852	5,717	5,664
2012	6,012	5,977	5,935	5,848	5,647	5,509	5,459
2013	6,058	6,024	5,982	5,896	5,693	5,556	5,505
2014	6,083	6,049	6,007	5,918	5,720	5,579	5,529
2015	6,155	6,121	6,078	5,993	5,788	5,653	5,601
2016	6,197	6,162	6,120	6,031	5,834	5,691	5,642
2017	6,293	6,259	6,216	6,129	5,927	5,789	5,738
2018	6,337	6,303	6,261	6,174	5,972	5,833	5,783
2019	6,426	6,392	6,350	6,260	6,063	5,919	5,871
2020	6,505	6,471	6,428	6,338	6,142	5,997	5,949

Table 12b. 2010 Load Responsibility Forecast with Carbon

Demand (MW)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
FERC Load (without losses)												
MUNICIPAL[12]	11.4	6.7	8.8	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COOPERATIVE[13]	201.8	216.4	221.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SPA[14]	18.0	17.2	17.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OMPA PSA[15]	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MDEA[16]	20.0	20.0	20.0	20.0	10.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total FERC Load (w/o losses)	276.2	285.3	292.5	46.6	35.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Losses (Loss factor = 0.0867)	23.9	24.7	25.4	4.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total FERC Load (losses added)	300.1	310.0	317.9	50.7	38.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Percentage Change in Total FERC Load		3.3%	2.6%	-84.1%	-23.5%	-100.0%	0.7%	0.7%	0.7%	0.7%	0.7%	-100.0%
Total Retail Load (with losses)	5,617	5,702	5,738	5,797	5,857	5,918	5,993	6,031	6,129	6,174	6,260	6,338
Percentage Change in Total Retail Load		1.5%	0.6%	1.0%	1.0%	1.0%	1.3%	0.6%	1.6%	0.7%	1.4%	1.2%
Load Responsibility (with losses)												
Load Responsibility = Total Retail Load + FERC, Losses Added (includes curtailable load)*	5,917	6,012	6,056	5,848	5,896	5,918	5,993	6,031	6,129	6,174	6,260	6,338
Percentage Change in Load Responsibility		1.6%	0.7%	-3.4%	0.8%	0.4%	1.3%	0.6%	1.6%	0.7%	1.4%	1.2%
Load Factor												
Load Responsibility = Total Retail Load + FERC, Losses Added*	5,917	6,012	6,056	5,848	5,896	5,918	5,993	6,031	6,129	6,174	6,260	6,338
Total Retail Sales + FERC, Losses Added	27,800,572	28,228,196	28,413,888	27,775,312	27,935,414	28,003,275	28,379,067	28,712,321	29,129,122	29,426,641	29,880,548	30,328,332
Load Factor	53.63%	53.60%	53.56%	54.22%	54.09%	54.02%	54.06%	54.34%	54.26%	54.41%	54.49%	54.63%

[12] Watonga contract can expire on February 28, 2012, Paris contract can expire on May 31, 2012, Orlando contract can expire on October 31, 2012 and the Geary contract expired on April 30, 2010
[13] AVEC contract can expire on November 30, 2011
[14] Paris contract can expire on May 31, 2012 and Vance contract can expire on May 31, 2012
[15] OMPA PSA contract terminates on December 31, 2013 and is removed from the forecast at that time due to the absence of an Evergreen clause in the contract
[16] MDEA contract 2 can expire on December 31, 2012 and MDEA contract 1 can expire on April 30, 2014

Table 15b. 2010 Retail Energy Forecast (MWh) with Carbon

	Year	Residential	Commercial	Public Authority	Street lighting	Industrial	Petroleum	Total
Arkansas	2009	722,794	715,816	135,578	8,891	981,796	10,304	2,575,178
	2010	729,347	725,335	143,298	8,956	1,099,760	10,819	2,717,515
	2011	733,282	747,491	151,308	9,003	1,105,259	10,873	2,757,216
	2012	752,026	777,057	156,834	9,058	1,110,785	10,927	2,816,686
	2013	766,666	797,870	162,393	9,116	1,116,339	10,982	2,863,367
	2014	783,666	822,900	167,665	9,176	1,121,921	11,037	2,916,365
	2015	800,889	848,349	173,395	9,236	1,127,531	11,092	2,970,493
	2016	817,279	874,066	180,019	9,295	1,133,168	11,148	3,024,975
	2017	833,785	899,344	187,461	9,353	1,138,834	11,203	3,079,980
	2018	849,114	923,260	195,175	9,410	1,144,528	11,259	3,132,746
	2019	865,012	951,658	203,182	9,466	1,150,251	11,316	3,190,884
	2020	883,388	985,868	212,194	9,522	1,156,002	11,372	3,258,346
Oklahoma	2009	8,060,751	5,727,776	2,735,363	53,892	2,574,462	2,913,067	22,065,310
	2010	8,157,927	5,794,732	2,742,487	54,950	2,587,334	2,927,633	22,265,063
	2011	8,219,551	5,841,987	2,801,885	55,718	2,600,271	2,942,271	22,461,683
	2012	8,328,204	5,952,202	2,856,143	56,483	2,613,272	2,956,982	22,763,287
	2013	8,352,483	6,058,848	2,895,709	57,258	2,626,339	2,971,767	22,962,404
	2014	8,433,563	6,176,924	2,940,894	58,046	2,639,470	2,986,626	23,235,522
	2015	8,516,789	6,322,535	3,002,087	58,841	2,652,668	3,001,559	23,554,479
	2016	8,563,586	6,442,195	3,063,555	59,644	2,665,931	3,016,567	23,811,478
	2017	8,636,584	6,595,717	3,142,380	60,452	2,679,261	3,031,650	24,146,044
	2018	8,660,752	6,700,902	3,208,971	61,269	2,692,657	3,046,808	24,371,358
	2019	8,763,791	6,852,221	3,291,204	62,093	2,706,120	3,062,042	24,737,471
	2020	8,860,799	7,001,367	3,366,444	62,925	2,719,651	3,077,352	25,088,538
Total OG&E	2009	8,783,545	6,443,591	2,870,941	62,783	3,556,258	2,923,371	24,640,489
	2010	8,887,273	6,520,068	2,885,784	63,907	3,687,094	2,938,452	24,982,578
	2011	8,952,833	6,589,478	2,953,193	64,721	3,705,530	2,953,144	25,218,899
	2012	9,080,230	6,729,259	3,012,977	65,541	3,724,058	2,967,910	25,579,973
	2013	9,119,150	6,856,718	3,058,102	66,374	3,742,678	2,982,749	25,825,770
	2014	9,217,228	6,999,823	3,108,560	67,222	3,761,391	2,997,663	26,151,887
	2015	9,317,679	7,170,884	3,175,483	68,076	3,780,198	3,012,651	26,524,972
	2016	9,380,865	7,316,261	3,243,574	68,938	3,799,099	3,027,714	26,836,453
	2017	9,470,369	7,495,061	3,329,841	69,805	3,818,095	3,042,853	27,226,023
	2018	9,509,865	7,624,162	3,404,146	70,678	3,837,185	3,058,067	27,504,105
	2019	9,628,802	7,803,879	3,494,387	71,559	3,856,371	3,073,358	27,928,356
	2020	9,744,187	7,987,235	3,578,638	72,447	3,875,653	3,088,724	28,346,884

Table 16b. Energy Forecast Accounting for Changes in Wholesale Load with Carbon

Energy (MWH)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
FERC Sales (without losses)												
MUNICIPAL[17]	40,183	35,505	32,511	6,562	0	0	0	0	0	0	0	0
AVEC[18]	896,336	947,936	886,737	0	0	0	0	0	0	0	0	0
SPA[19]	71,232	76,298	77,731	32,487	0	0	0	0	0	0	0	0
OMPA[20]	210,182	219,000	219,000	219,000	219,000	0	0	0	0	0	0	0
MDEA[21]	125,849	122,640	122,640	122,640	65,533	21,844	0	0	0	0	0	0
Total FERC Sales	1,343,783	1,401,380	1,338,619	380,689	284,533	21,844	0	0	0	0	0	0
Growth Rate in FERC sales		4.3%	-4.5%	-71.6%	-25.3%	-92.3%	-100.0%	0.5%	0.0%	0.0%	0.0%	0.0%
Retail Sales (without losses)												
Residential	8,783,545	8,887,273	8,952,833	9,080,230	9,119,150	9,217,228	9,317,679	9,380,865	9,470,369	9,509,865	9,628,802	9,744,187
Commercial	6,443,591	6,520,068	6,589,478	6,729,259	6,856,718	6,999,823	7,170,884	7,316,261	7,495,061	7,624,162	7,803,879	7,987,235
Industrial	3,556,258	3,687,094	3,705,530	3,724,058	3,742,678	3,761,391	3,780,198	3,799,099	3,818,095	3,837,185	3,856,371	3,875,653
Industrial Petroleum	2,923,371	2,938,452	2,953,144	2,967,910	2,982,749	2,997,663	3,012,651	3,027,714	3,042,853	3,058,067	3,073,358	3,088,724
Total Industrial	6,479,629	6,625,546	6,658,674	6,691,967	6,725,427	6,759,054	6,792,849	6,826,814	6,860,948	6,895,252	6,929,729	6,964,377
Public Authority and Street Lighting	2,933,724	2,949,691	3,017,914	3,078,517	3,124,476	3,175,781	3,243,559	3,312,513	3,399,645	3,474,825	3,565,945	3,651,085
Total Retail Sales	24,640,489	24,982,578	25,218,899	25,579,973	25,825,770	26,151,887	26,524,972	26,836,453	27,226,023	27,504,105	27,928,356	28,346,884
Growth Rate in Retail Sales		1.4%	0.9%	1.4%	1.0%	1.3%	1.4%	1.2%	1.5%	1.0%	1.5%	1.5%
Total MWH Sales (with losses)												
Total Retail Sales + FERC	25,984,271	26,383,958	26,557,518	25,960,662	26,110,304	26,173,732	26,524,972	26,836,453	27,226,023	27,504,105	27,928,356	28,346,884
Losses[22]	1,816,301	1,844,239	1,856,370	1,814,650	1,825,110	1,829,544	1,854,096	1,875,868	1,903,099	1,922,537	1,952,192	1,981,447
Total Retail Sales + FERC, Losses Added	27,800,572	28,228,196	28,413,888	27,775,312	27,935,414	28,003,275	28,379,067	28,712,321	29,129,122	29,426,641	29,880,548	30,328,332
Growth Rate in Total Sales		1.5%	0.7%	-2.2%	0.6%	0.2%	1.3%	1.2%	1.5%	1.0%	1.5%	1.5%

[17] Watonga contract can expire on February 28, 2012, Paris Contract can expire on May 31, 2012, Orlando contract can expire on October 31, 2012 and the Geary contract expired on April 30, 2010
[18] AVEC contract can expire on November 30, 2011
[19] Paris contract can expire on May 31, 2012 and Vance contract can expire on May 31, 2012
[20] OMPA PSA contract terminates on December 31, 2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.
[21] MDEA contract 2 can expire on December 31, 2013 and MDEA contract 1 can expire on April 30, 2014
[22] The energy loss factor is 0.0699 for 2009 and beyond

Figure 1b. Energy Model Forecast Outcomes by Weather Probability with Carbon

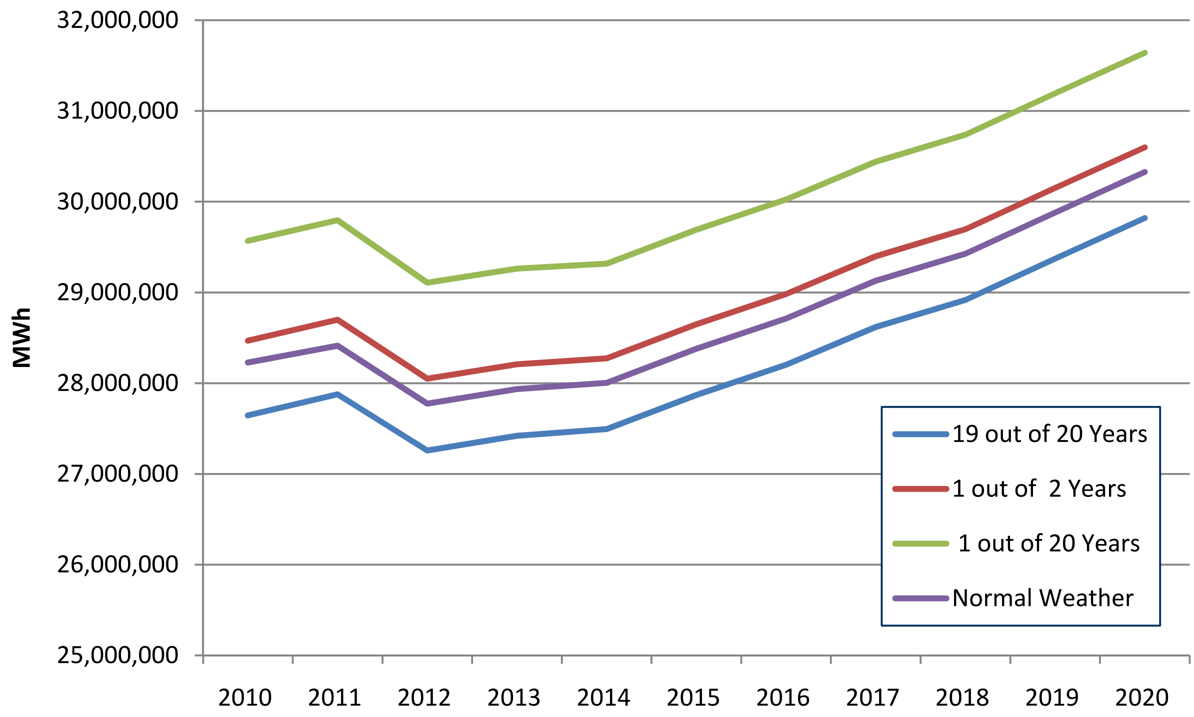


Figure 2b. Load Responsibility Outcomes by Weather Probability with Carbon

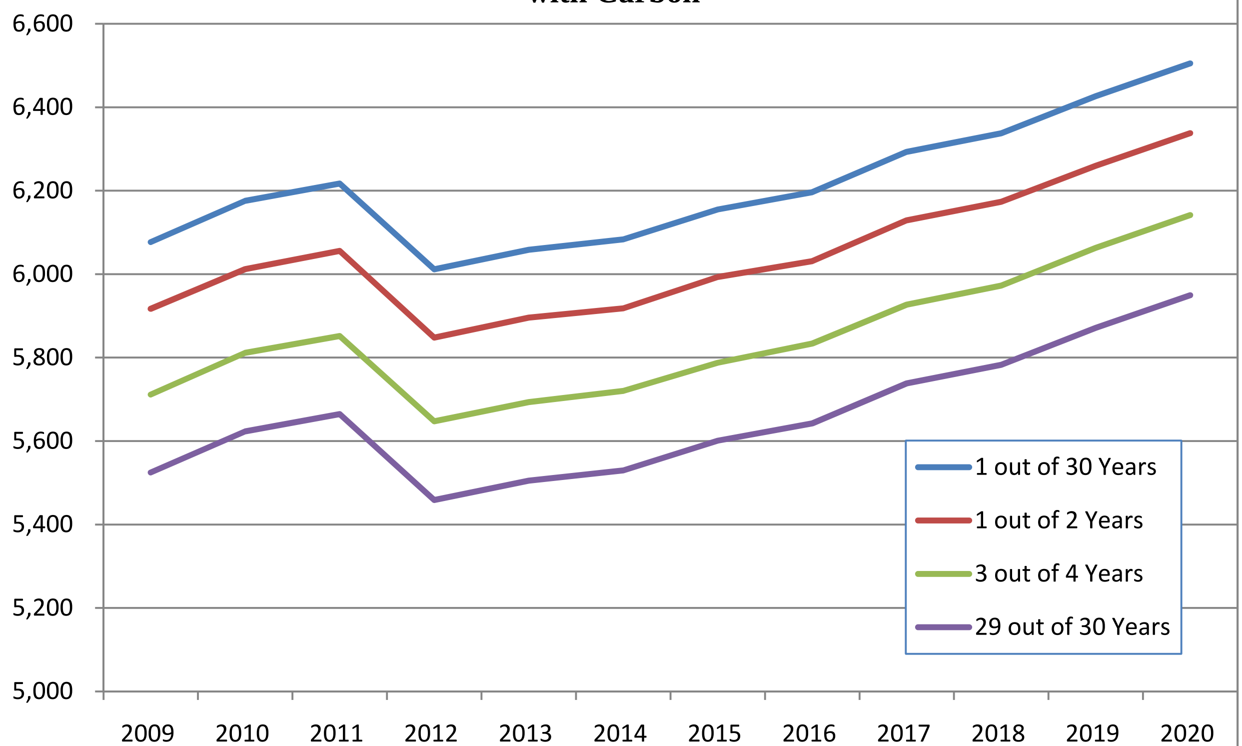


Figure 3b. Retail and Wholesale Energy - Weather Normalized Historical and Forecast Sales with Carbon

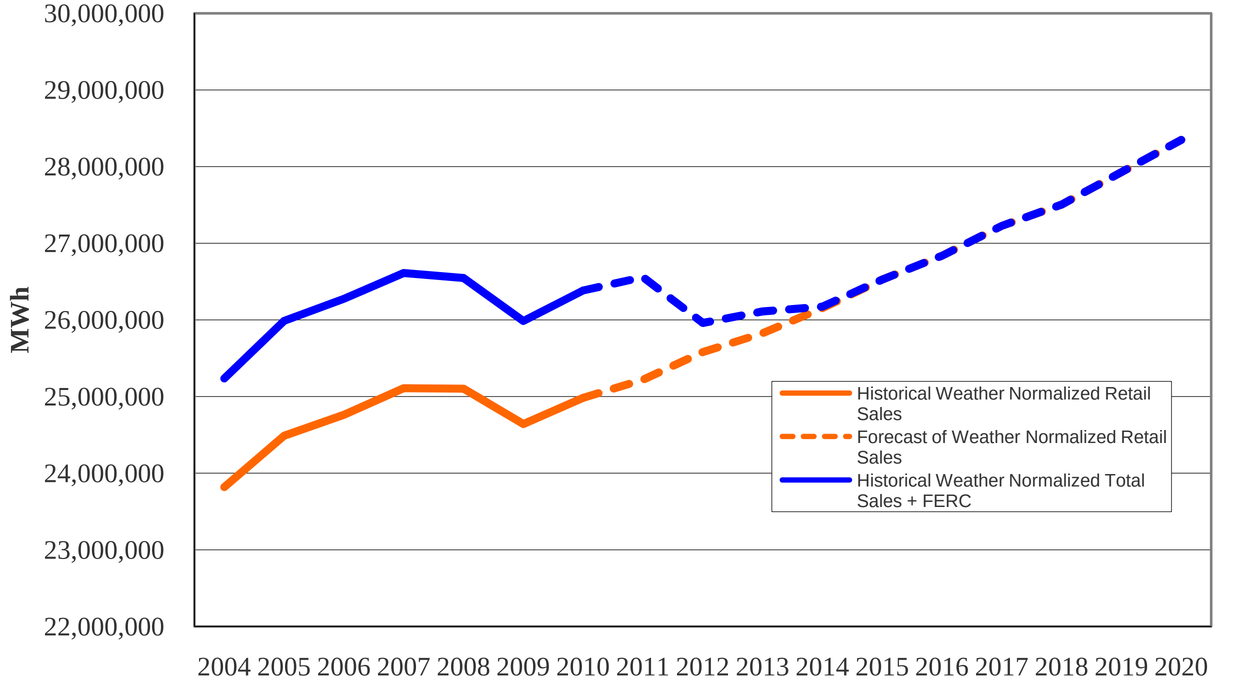


Figure 4b. Native Load Responsibility - Weather Normalized Historical and Forecast Loads with Carbon

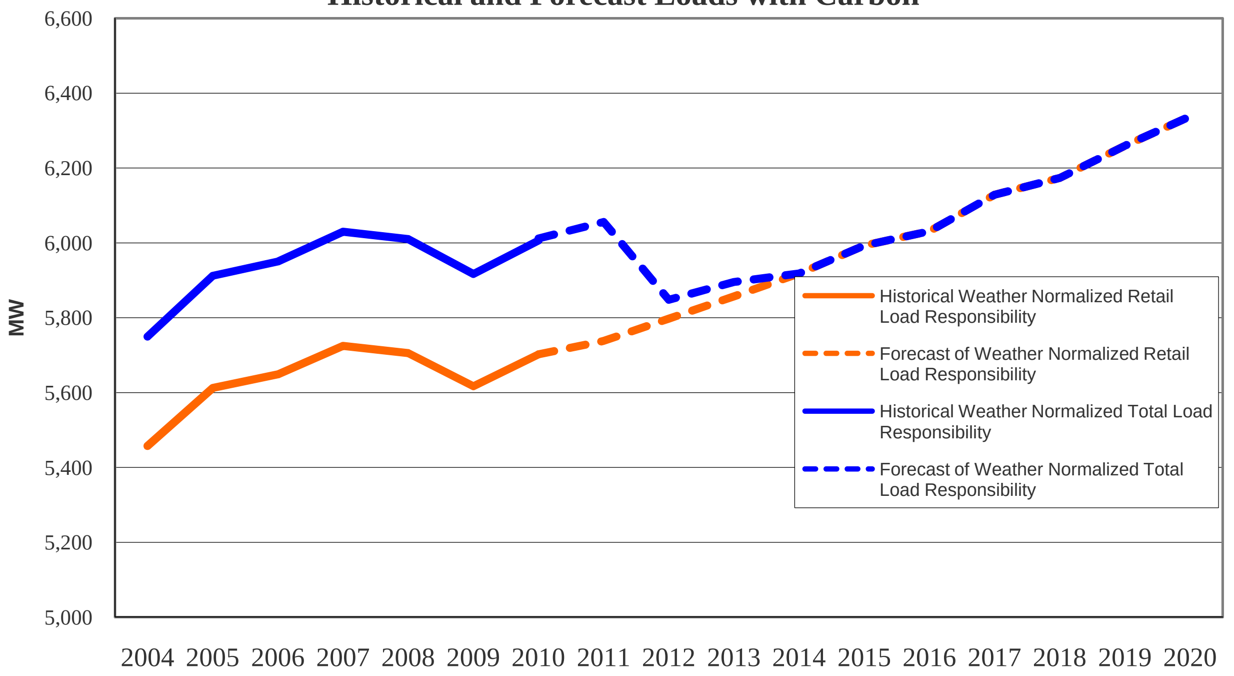
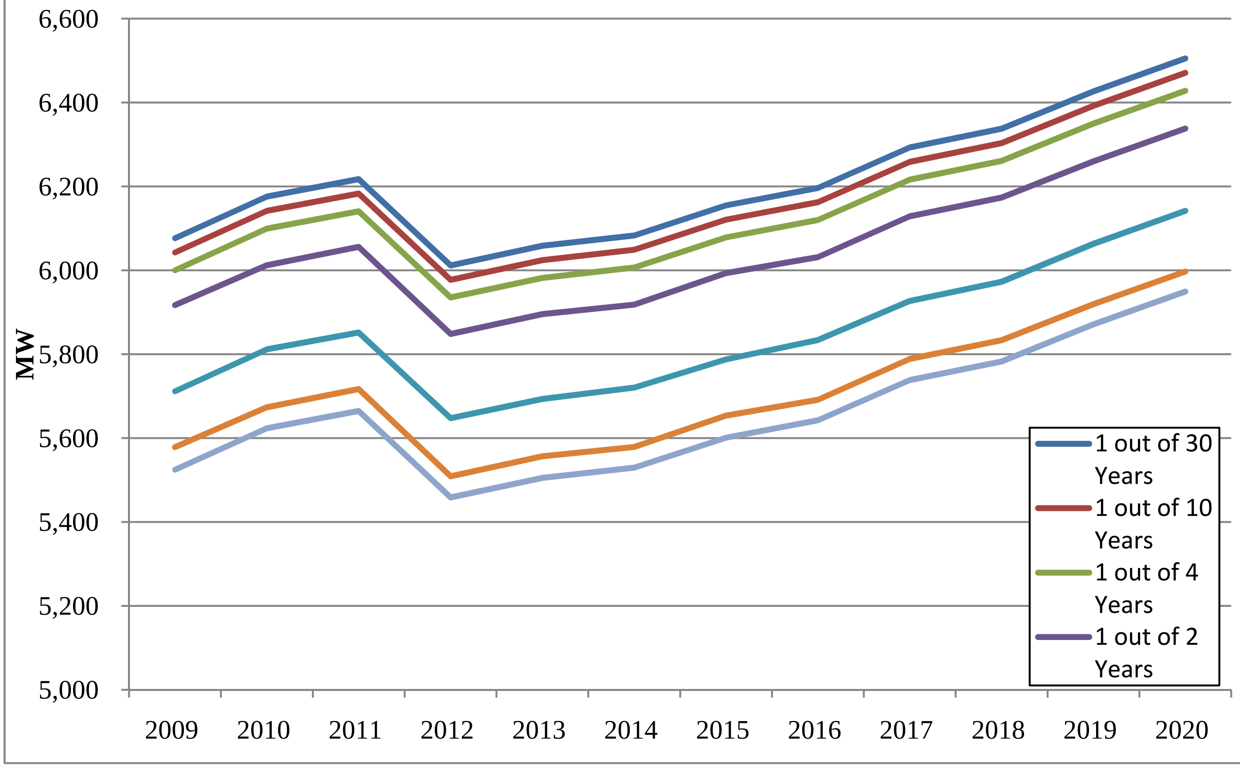


Figure 6b. Peak Demand Model Forecasts by Weather Probability with Carbon with Carbon



Appendix B – OG&E 2010 Capability Report

OKLAHOMA GAS AND ELECTRIC COMPANY
GENERATING UNITS
AS OF 12-31-10

Plant	Unit No.	Name Plate Data: Turbine KW Rating – Unit	Turbine KW Rating – Plant	Generator Max KW at Max H2 – Unit	Generator Max KW at Max H2 – Plant	Year Installed	Summer Capabilities: KW Net (2010 Actual)[5] By Units	KW Net (2010 Actual)[5] By Plants	KW Net (2011 Expected)[6] By Units	KW Net (2011 Expected)[6] By Plants	Planned 2011 Capacity Recovery
Muskogee	3	150,000		173,400		1956			0		
	4	507,776		572,400		1977	505,000		505,000		
	5[7]	507,776		572,400		1978	423,000		500,000		77,000
	6	508,418	1,673,970	572,400	1,890,600	1984	502,000	1,430,000	502,000	1,507,000	
Seminole	1	509,719		567,000		1971	490,670		500,000		9,330
	1GT	20,150 B		23,580		1971	16,920		16,920		
	2	504,604		567,000		1973	494,000		500,000		6,000
	3	505,980	1,540,453	567,000	1,724,580	1975	502,000	1,503,590	503,000	1,519,920	1,000
Sooner[3]	1	568,939		568,800		1979	522,000		522,000		
	2	568,939	1,137,878	568,800	1,137,600	1980	524,000	1,046,000	524,000	1,046,000	
Horseshoe Lake	6	150,000		163,200		1958	158,500		158,500		
	7	193,600 D		219,725		1963	213,800		213,800		
	7GT	26,500 D		27,200		1963	12,700		12,700		
	8	404,450		442,800		1969	380,500		380,500		
	9	45,000		60,491		2000	45,500		45,500		
	10	45,000	864,550	60,491	973,907	2000	45,500	856,500	45,500	856,500	
Mustang	1	50,000		81,508		1950	50,000		50,000		
	2	50,000		62,500		1951	51,000		51,000		
	3[4]	121,047		133,411		1955	113,000		113,000		
	4	230,000		252,506		1959	253,440		253,440		
	5A	40,000 G		41,850		1971	32,000		32,000		
	5B	40,000 G	531,047	41,850	613,625	1971	32,000	531,440	32,000	531,440	
Enid[8]	1GT	14,000 C		15,000		1965			0		
	2GT	14,000 C		15,000		1965			0		
	3GT	14,000 C		15,000		1965			14,000		14,000
	4GT	14,000 C	56,000	15,000	60,000	1965		0	0	14,000	
Woodward	GT	11,250 B	11,250	11,500	11,500	1963			0	0	
8 Plants 29 Units			5,815,148		6,411,812			5,367,530		5,474,860	
McClain[1]		184,904 D		198,050		2001	128,475		128,475		
	1GT	171,700 D		176,630		2001	111,469		111,469		
	2GT	171,700 D	528,304	176,630	551,310	2001	111,946	351,890	111,946	351,890	
Redbud[2]	1ST	155,500 D		159,503		2002					
	1GT	159,000 D	314,500	198,900	358,403	2002	148,777		148,777		
	2ST	155,500 D		159,503		2002					
	2GT	159,000 D	314,500	198,900	358,403	2002	147,012		147,012		
	3ST	155,500 D		159,503		2002					
	3GT	159,000 D	314,500	198,900	358,403	2002	147,951		147,951		
	4ST	155,500 D		159,503		2002					
	4GT	159,000 D	314,500	198,900	358,403	2002	145,401		145,401		
			1,258,000		1,433,612			589,141		589,141	
Renewables											
Centennial	1-80	1,500/each	120,000		120,000			7,000	0	7,000	
OU Spirit	1-44	2.300/each	101,000		101,000			9,000	0	9,000	
Total			7,822,452		8,617,734			6,324,561		6,431,891	

Approved by John Wendling
John Wendling
Managing Dir Generation Planning/Control

Reviewed by Kim Morphis
Kim Morphis
Manager Power Operations

	2010 Actual	2011 Expected
Coal	2,476,000	2,553,000
Combined Cycle Gas	941,031	941,031
Gas Steam	2,706,910	2,723,240
Gas Peaking[9]	184,620	198,620
Wind	16,000	16,000
TOTAL	6,324,561	6,431,891

Notes:
1. OGE owns 77% of the plant
2. 51% ownership of the plant to OG+E became effective on Sept 29, 2008 (no SPP test was completed i
3. The Turbine HP-IP were upgraded, ratings are gross not net rating
4. The turbine was upgraded in 1985

Notes B, C, D, E, & G on Page 3

5. The Capacity values are in accordance with the SPP criteria .
6. Expected values due to planned maintenance activites (if applicable)
7. Planned maintenance Apr-May 2011 to restore capacity
8. Planned maintenance to restore summer capacity
9. Includes Horseshoe 7GT

Prepared by George Bohn, 553-3204
Power Supply Services M/C 610

Appendix C – Annual Portfolio NPVRR for Reference Scenario

Annual Revenue Requirement*, Reference Scenario ($Billions)

NO WIND	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	30 YEAR NPVRR
Benchmark - CC	1.21	1.31	1.32	1.44	1.37	1.51	1.59	1.71	1.83	1.88	21.4
Benchmark - CT	1.21	1.31	1.32	1.44	1.37	1.51	1.55	1.62	1.72	1.75	21.5
Scrub - CC	1.21	1.33	1.46	1.68	1.78	1.89	1.96	2.06	2.17	2.21	23.8
Scrub - CT	1.21	1.33	1.46	1.68	1.78	1.88	1.92	1.97	2.06	2.07	23.8
Hybrid Convert - CC	1.21	1.32	1.40	1.58	1.78	1.91	1.98	2.12	2.22	2.28	24.7
Hybrid Convert - CT	1.21	1.32	1.40	1.58	1.78	1.90	1.94	2.03	2.11	2.17	25.1
Hybrid Replace - CC	1.22	1.39	1.55	1.74	1.91	2.01	2.07	2.16	2.27	2.29	25.1
Hybrid Replace - CT	1.22	1.39	1.55	1.74	1.91	2.00	2.03	2.08	2.16	2.15	24.9
Convert - CC	1.21	1.31	1.32	1.46	1.93	2.05	2.13	2.32	2.41	2.51	27.0
Convert - CT	1.21	1.31	1.32	1.46	1.93	2.05	2.09	2.23	2.30	2.41	27.6
Replace - CC	1.23	1.48	1.70	1.84	2.16	2.23	2.29	2.36	2.47	2.45	27.3
Replace - CT	1.23	1.48	1.70	1.84	2.16	2.22	2.25	2.28	2.36	2.30	27.0

WIND WITHOUT PTCS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	30 YEAR NPVRR
Benchmark - CC	1.29	1.38	1.38	1.48	1.42	1.55	1.63	1.74	1.84	1.91	21.6
Benchmark - CT	1.29	1.38	1.38	1.48	1.42	1.54	1.59	1.65	1.73	1.76	21.7
Scrub - CC	1.29	1.40	1.51	1.73	1.82	1.92	1.99	2.09	2.19	2.23	24.0
Scrub - CT	1.29	1.40	1.51	1.73	1.82	1.92	1.95	2.00	2.08	2.09	23.9
Hybrid Convert - CC	1.29	1.39	1.46	1.63	1.81	1.93	2.01	2.14	2.23	2.29	24.9
Hybrid Convert - CT	1.29	1.39	1.46	1.63	1.81	1.93	1.97	2.05	2.12	2.17	25.2
Hybrid Replace - CC	1.30	1.46	1.61	1.78	1.94	2.04	2.11	2.19	2.29	2.31	25.3
Hybrid Replace - CT	1.30	1.46	1.61	1.78	1.94	2.03	2.07	2.10	2.18	2.16	25.1
Convert - CC	1.29	1.38	1.38	1.50	1.95	2.08	2.14	2.33	2.42	2.51	27.1
Convert - CT	1.29	1.38	1.38	1.50	1.95	2.08	2.10	2.24	2.31	2.42	27.7
Replace - CC	1.31	1.56	1.76	1.89	2.21	2.27	2.33	2.39	2.50	2.47	27.5
Replace - CT	1.31	1.56	1.76	1.89	2.21	2.26	2.29	2.31	2.39	2.33	27.2

*The Revenue Requirement in these tables includes a recovery of return on rate base, expenses, and production costs. The calculation assumes OG&E recovers expenditures in the year they are made and recoveries based on the capital structure, cost of capital and tax rate authorized by the Oklahoma Corporation Commission in OG&E's July, 2009 Rate Case order.

Appendix D – OGE 2011 IRP Oklahoma Collaborative Technical Conference

OGE 2011 IRP Oklahoma Collaborative Technical Conference

February 22, 2011

Meeting Documentation

Introduction

The 2011 IRP submittal and associated Oklahoma Stakeholder Meeting are being performed pursuant to an agreement reached in the Commission-approved joint stipulation and settlement agreement in the Crossroads docket (Cause No. PUD 201000037). The stipulation reads in relevant part:

> M. The Stipulating Parties agree that on or before May 1, 2011, OG&E will submit an interim, updated Integrated Resource Plan ("IRP") as contemplated by Subsection 37 of Chapter 35 of the Commission's Rules, provided that:
>
> 1) The updated IRP analysis will specifically address the need and timing for additional wind resources in OG&E's system, including but not limited to various amounts of wind and timing of additional wind including assessments of the benefits based on consideration of the operation of the SPP day-ahead market, transmission limitations/requirements for expanded wind resource development, the added costs for fossil-fuel-fired power plants when those fossil fuel plants are used to accommodate variable wind generation, current expectation of the impacts of regional haze rules on OG&E's coal generation and a range of scenarios for natural gas prices and climate legislation and other factors which may impact the amounts and timing of wind resource additions over the next ten (10 years.
>
> 2) No less than sixty (60) days prior to the filing of the updated integrated resource plan, the Stipulating Parties further agree that OG&E will hold a collaborative technical conference for all stakeholders in order to allow all stakeholders the opportunity to provide input regarding utility objectives, assumptions, and planning scenarios to be contained in the updated IRP analysis.

The Collaborative Technical Conference was held on February 22, 2009 in OGE's offices. Several stakeholders participated by teleconference. The participants were:

OGE: Leon Howell, Kimber Shoop, Jesse Langston, Zac Hager, Michael Collins, Rhonda Redden, Bill Wilkerson

Commission Staff: Karen Forbes, Joel Rodriguez, Tanya Hinex-Ford, Trent Campbell

Attorney General: Bill Humes, Dan Peaco

OIEC: Tom Schroedter, Scott Norwood

Devon Energy: A.J. Ferate

Chesapeake Energy: Jamie Maddy

Oklahoma Sustainability Network/Chermac/CPV/Sierra Club: Jon Laasch, Cheryl Vaught

OGE Shareholders: Ron Stakem

AES Shady Point: Kendall Parish

Oklahoma Sustainability Network: Montel Clark

Sierra Club and Novus Wind Power: Bud Scott

The meeting was divided into two segments. The first part focused on a presentation that was made by Leon Howell, OGE's Director, Resource Planning. Stakeholders were encouraged to ask clarifying questions throughout the presentation. The second part of the meeting was devoted to stakeholder feedback on OGE's IRP.

The meeting began with an introduction by OGE, introduction of the participating stakeholders and brief comments on the conduct of the meeting by the facilitator.[1] The facilitator indicated that he would prepare and distribute these meeting notes.

Part 1: OGE Presentation and Questions

The meeting notes that follow incorporate presentation materials, comments by OG&E supplementing the presentation slides, followed by a summary of questions by stakeholders and the OGE response.

[1] The meeting was facilitated by Robert C. Yardley, Jr. a former regulator and Executive Advisor to Concentric Energy Advisors.

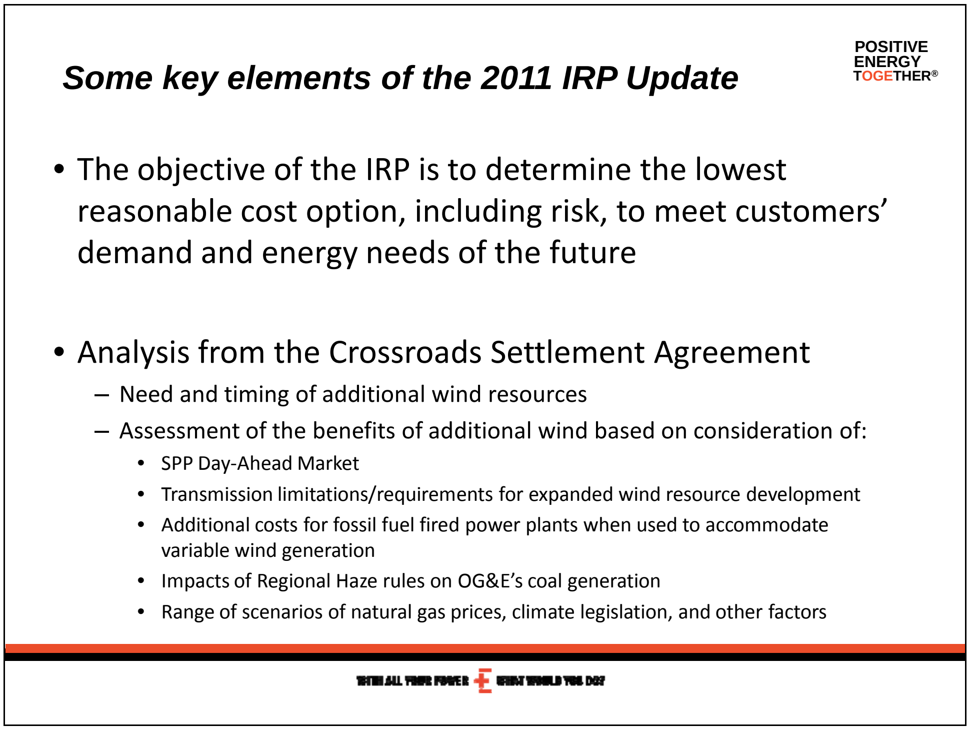
Purpose of Meeting

POSITIVE
ENERGY
TOGETHER®

- Gather Stakeholder input to OG&E's IRP
- Crossroads Joint Stipulation and Settlement Agreement – June 29, 2010
  - On or before May 1, 2011, OG&E will submit an interim, updated IRP
  - No less than sixty (60) days before filing of the updated [IRP],…OG&E will hold a collaborative technical conference for all stakeholders
  - Opportunity to provide input regarding utility objectives, assumptions, and planning scenarios to be contained in updated IRP analysis

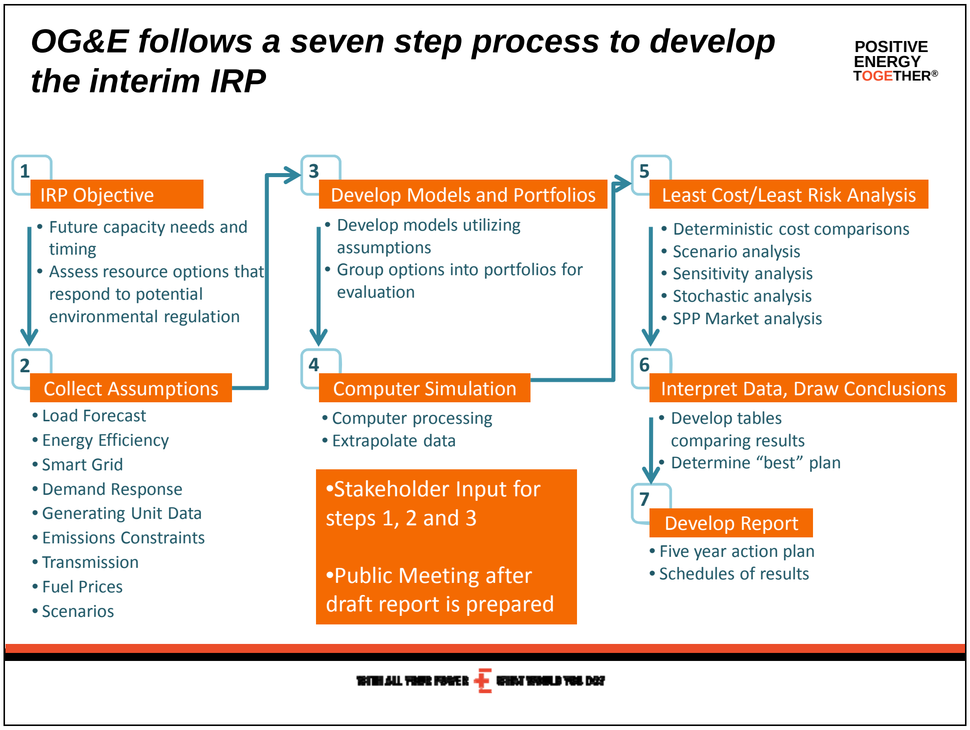
OG&E Comments:

- OG&E is in the process of developing an IRP to comply with the Crossroads Settlement agreement.
- In today's meeting we will present and seek feedback on the Process, Objectives, Assumptions and Planning portfolio or scenarios.
- Next scheduled IRP under the OCC Electric Rules is due to be submitted in October 2012, so we will be going through this process again next year.



OG&E Comments:

- All of the assumptions from the 2010 IRP will be updated.
- We will identify the cost/benefits of wind additions that would allow OG&E to meet the State Renewable Portfolio goal of 15% by 2015
- In addition, we will model an array of portfolios to get a broad understanding of the options available to comply with possible emission regulations. These regulations include Regional Haze and Maximum Available Control Technology (MACT) for Hazardous Air Pollutants (HAPs)
- Each portfolio will be analyzed in scenarios that are defined to consider climate change legislation.
- Sensitivity analyses will performed on the top portfolios to examine alternative fuel and emissions prices
- Planned SPP transmission additions including the resulting incremental costs to OG&E's customers will identified



OG&E Comments:

- Main objective of IRP is the needs and timing of future capacity additions
- Myriad assumptions go into the IRP – the IRP team relies on several other groups within OGE to provide assumptions relevant to their areas
- Stakeholder input is being sought for the first three steps of the process: objectives, assumptions and the portfolios to be examined
- Computer simulation is a large piece of the process – very time consuming

Key inputs and assumptions

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- Load forecast
- System characteristics
  - DSM Programs, PPA/Cogen Contracts, Generators
- New generation options
  - Capital and O&M Costs, Operating Characteristics
- Wind additions
- Environmental requirements
- Transmission expansion
- Price forecasts
  - Natural Gas and Coal
  - CO_2

OG&E Comments:

- We will review each of these areas in the following slides

Load Forecast

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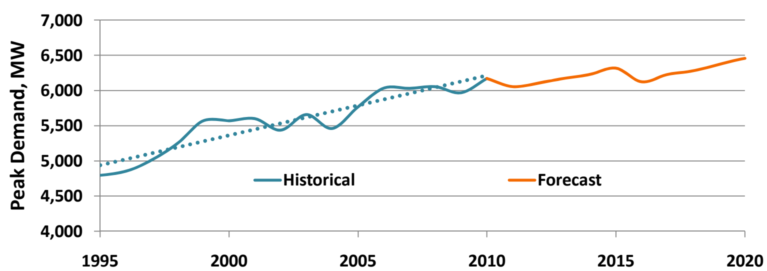

	2012	2013	2014	2015	2016	2017	2018	2019	2020	Avg Growth Rate (%)
Demand, MW	6,104	6,172	6,228	6,317	6,123	6,228	6,278	6,371	6,456	0.73
Energy, GWh	29,118	29,401	29,638	30,102	29,224	29,682	30,013	30,501	30,950	0.96

OG&E Comments:

- OG&E does an econometric-based load forecast annually.
- We will use the most recent forecast that was complete in September 2010.
- The forecast will be included in the IRP report as schedule C.
- OG&E's demand forecast does not reflect new demand side supply options such as demand response due to smart grid or energy efficiency programs.
- The demand forecast reflects historical energy efficiency programs that are reflected in the data used to develop the econometric forecast equations. It also includes the likely future demand response such as load curtailments based on experience during recent peak periods.
- Wholesale load contract termination is reflected in the forecast most notably in the 2016 as shown by the dip in the forecast.
- As with the demand forecast the energy forecast does not reflect future energy reduction due to demand side supply options including demand response due to smart grid or energy efficiency programs.
- The energy forecast does reflect historical energy efficiency programs.
- As noted the total load includes wholesale load along with transmission and distribution loses.
- The retail demand growth rate is projected to be 1.32% with an energy growth rate of 1.49%

Questions:

- Does the forecast assume that wholesale load contracts expire 2015/2016, causing the dip?
  - RESPONSE: That is correct

OG&E includes sales agreements in the IRP

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Wholesale Load

Peak Load, MW	2011	2012	2013	2014	2015	2016
AVECC	221	224	228	232	236	0
SPA	18	0	0	0	0	0
Municipal	9	2	38	0	0	0
OMPA	25	25	25	0	0	0
MDEA	20	20	11	0	0	0

OG&E Comments:

- OG&E has recently terminated wholesale load agreements as contracts come to term. Additional agreements will expire through 2015.

Questions:

- Has the AVECC termination been pushed back?
  - o RESPONSE: Yes, the agreement was recently extended through 2015. The downturn in the economy provided reduced capacity responsibility which allowed us to continue to serve AVECC and avoid reallocating those costs to retail customers.

Demand Side Resources are included in OG&E's resource plan

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Program	Peak Load Reduction (MW)								
	2012	2013	2014	2015	2016	2017	2018	2019	2020
SmartGrid - Residential DR	71	143	216	218	219	221	223	225	227
SmartGrid - Commercial DR	0	0	23	47	70	71	72	72	73
SmartGrid - Distribution Automation	8	17	26	37	48	60	75	75	75
Energy Efficiency	26	38	38	38	36	34	32	32	32
Load Curtailment	46	47	48	49	49	50	50	51	52
Total Peak Reduction	151	245	351	389	422	436	452	455	459

- *SmartGrid forecast reflects plan approved in Cause No. PUD 201000029*
- *Energy Efficiency forecast reflects programs approved in Cause No. PUD 200900200*
- *Load Curtailment forecast reflects 2010 performance levels*

OG&E Comments:

- OG&E plans to reduce its peak demand requirements by 459 MW or 7% by 2020 through Demand Response, Distribution automation, energy efficiency and load curtailment.
- Smart Grid and Energy efficiency programs have both been approved by the OCC and Load Curtailment is an approved tariff (Load Reduction Rider).

Questions:

- Is there any industrial demand response?
  - o RESPONSE: There are industrial DR programs, but they were not part of the benefits included in the SmartGrid program and are therefore not included in this slide.
- Why is projected load curtailment about 100MW less than the last IRP?

- o RESPONSE: This projection reflects actual performance results from 2010 curtailments. Load curtailment remains a priority for OG&E and we plan on being more aggressive with our load curtailment program in the future, so it is possible that these numbers will increase.

Supply Side Resources

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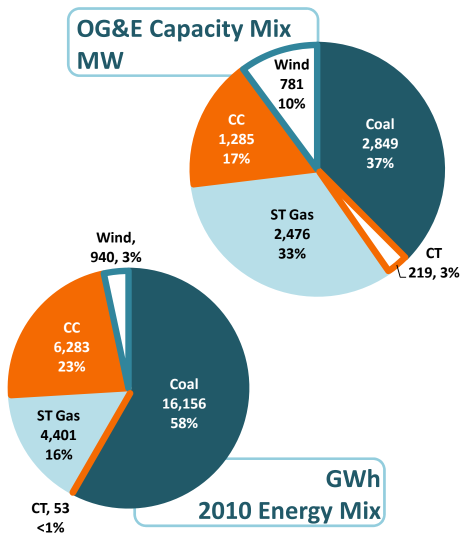


Type	Unit	Capability (MW)
Coal	Muskogee 4, 5 & 6	1,499
	Sooner 1 & 2	1,030
	AES Shady Point (PPA)	320
CC	McClain	360
	Redbud	585
	Horseshoe Lake 7	220
	PowerSmith (PPA)	120
ST Gas	Seminole 1-3	1,468
	Horseshoe Lake 6 & 8	539
	Mustang 1 - 4	451
CT	Horseshoe Lake 9 & 10	88
	Tinker 5A & 5B	64
	Enid & Woodward	50
	Seminole GT	17
Wind	OG&E Owned	448
	PPA	333

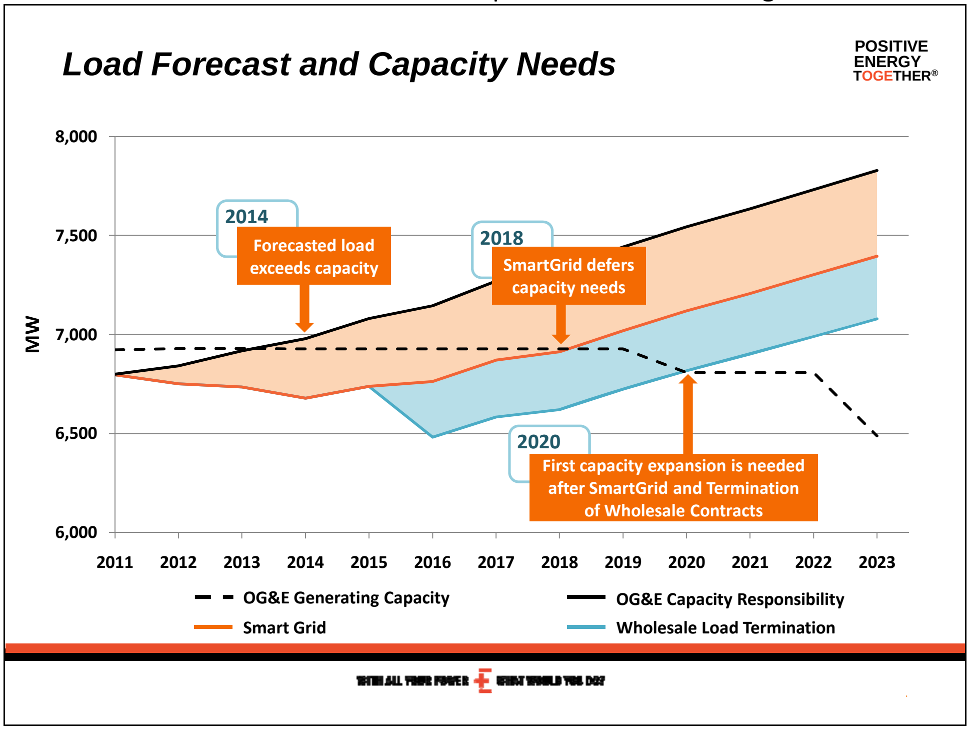
OG&E Comments:

- Today OG&E operates a diverse generation fleet that includes coal generation, gas generation and wind generation.
- The capacity of wind reflected on this slide represents nameplate capacity and not the amount of capacity that counts towards OG&E's planning capacity margin requirements. We use 5% capacity credit for the wind farms we don't have a sufficient track record to claim higher capacity credits for purposes of meeting the SPP reserve margin criteria.
- The wind generation includes the Crossroads facility that will come on line in 2012.
- OG&E will not assume any retirements through the study period. This assumption reflects the results of the retirement study OG&E performed in the past.
- OG&E has purchase power agreements with both PowerSmith and AES Shady Point that come to term during the study period.
- For modeling purposes, it will be assumed that each contract will be terminated and replaced with new build capacity, effectively pricing that capacity based on a new build cost.

Questions:

- When do the AES and Smith contracts expire?
  - o RESPONSE: Smith in 2019, AES in 2023.
- Are there purchase options on those contracts at the end of the period?

- RESPONSE: I don't believe there is a provision in the existing contracts for that.



OG&E Comments:

- This chart indicates how OG&E plans on getting to the year 2020 with no new fossil fuel generation.
  - The capacity of OG&E's existing generation is shown as the dotted line and reflect termination assumption of both PowerSmith and AES purchase power contracts
  - Next I'll put on the graph our load forecast. From this chart you can see the capacity and load lines cross in 2013 indicating that OG&E will need new capacity by 2014 if no other actions are taken.
  - The effect of demand response resulting in pushing capacity needs to 2018.
  - Finally with the termination of wholesale load the need for new capacity will be delayed until 2020.

Questions:

- Does the termination of the wholesale contracts extend the need for capacity beyond 2020
  - RESPONSE: We are right at 2020, within about 10 MW for capacity need assuming wholesale contracts terminate.

Three supply side options met screening criteria to meet future capacity needs

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EIA AEO 2011 Resource Options

Resource	$/kW
• Adv PC w/o CCS	$ 2,844
• IGCC w/o CCs	$ 3,221
• IGCC CCS	$ 5,348
• **Conv NGCC**	**$ 978**
• Adv NGCC	$ 1,003
• Adv NGCC CCS	$ 2,060
• Conv CT	$ 974
• **Adv CT**	**$ 665**
• Fuel Cell	$ 6,835
• Nuclear	$ 5,339
• Biomass	$ 3,860
• Geothermal	$ 4,141
• Landfill Gas	$ 8,232
• Conv Hydro	$ 3,078
• **Wind**	**$ 2,438**
• Wind Offshore	$ 5,975
• Solar Thermal	$ 4,692
•Solar PV	$ 4,755

New Generating Unit Options

Unit	Overnight Capital Cost ($/kW)			Capacity (MW)	
	AEO 2011	AEO 2010	% Change	AEO 2011	AEO 2010
NG CC	978	1,005	-3	540	250
Adv CT	665	662	< 1	210	230
Wind	2,438	2,007	21	100	50

** EIA Annual Energy Outlook 2011 will be used in this IRP Update*

OG&E Comments:

- Department of Energy, Energy Information Administration is referenced as EIA
- OG&E will base construction costs of new generation facilities on the recently released 2011 Annual Energy Outlook. A full list of resource options along with costs is given in the table on the left side of this slide.
- OG&E has screened facilities using the same process as outlined in the 2010 IRP. The screening criteria include proven technology, cost, and public acceptance. The units that will be considered for future generation needs are listed in the table on the right. Coal plants are not included do to the last criterion.
- In this interim IRP we do not consider nuclear because it was not one of the best options in the last IRP, and its costs have increased about 30% since the last estimate. It will be analyzed in the next IRP.

Some factors effect the need and timing of potential additional wind resources

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- Oklahoma HB 3028 – Oklahoma Energy Security Act
  - Effective November 1, 2010
  - Establishes renewable energy standard to set a goal that by 2015, 15% of all installed capacity within the state shall be from renewable sources
  - With 255 MW of additional wind generation, 15% of OG&E's capacity will be renewable
- Production Tax Credits
  - Extended through December 31, 2012 by American Recovery and Reinvestment Act of 2009
  - Could be extended but no legislation is currently proposed

OG&E Comments:

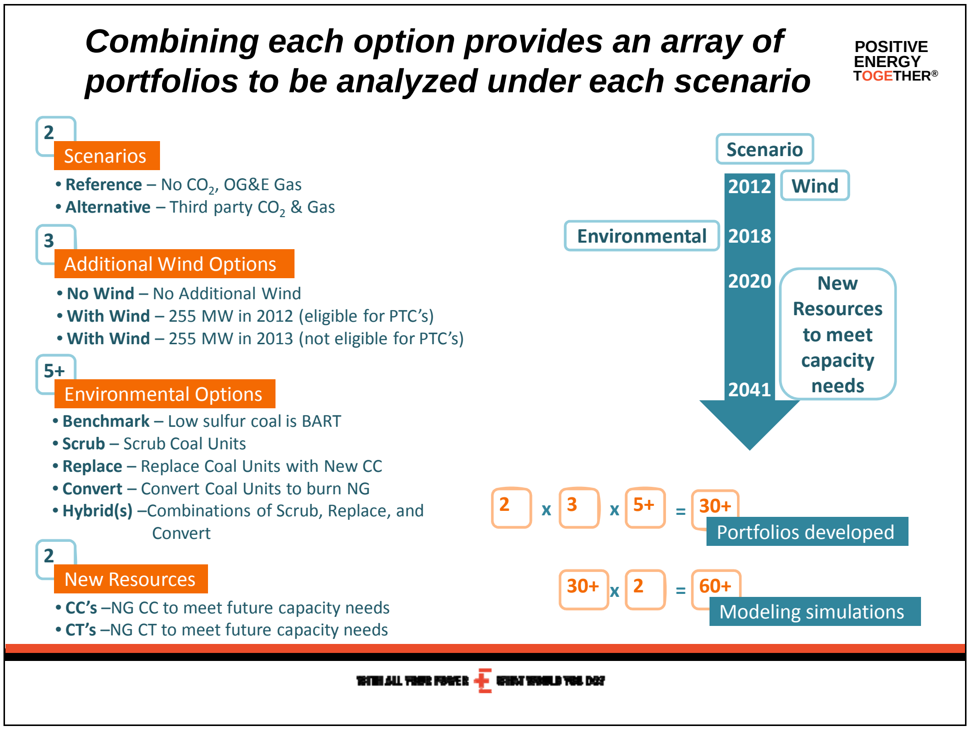
- HB 3028 establishes a goal of 15% of installed capacity come from renewable resources.
- 25% of renewable resources can come from demand side resources.
- Relying on expected DSM OG&E would need approximately 1035MW of wind generation to meet the goal. With the addition of Crossroads in 2012 we have 781MW
- Production tax credits and accelerated depreciation offer a significant reduction in wind generation costs

Questions:

- Has OGE broken out whether the 255 MW of wind needed could be PPA or owned or both?
  - RESPONSE: In the IRP, we are assuming owned resources because we do not want to forecast what PPA prices could be. We would go through the RFP process to acquire any additional wind.
- Is OGE trying to meet the 15% goal, the HB establishes a statewide goal?
  - RESPONSE: Yes, OGE will try to meet that goal. We are assuming everyone will install 15% of their capacity to help meet the goal. As in the past, if we don't show benefits from a resource, we won't add it, and wind may not show benefits after PTC's expire. However, OG&E will only add wind resources if they provide benefits to our customers.
- How did you get the 255MW?
  - RESPONSE: The goal is based on 15% of installed capacity, but the bill is vague. We assumed 15% of installed capacity. OG&E anticipates being able to take advantage of the 25% of the goal allowed to be provided by DSM, based on OGE demand response and energy efficiency programs.
- After the 255, have we estimate what % of total energy wind would be?

- RESPONSE: We would be around 12-13% of energy production.

- Is that a mandate or goal?
  - RESPONSE: It's a goal, which is why we will still determine if meeting that goal is beneficial to customers.
- What are your considerations when looking at wind resources?
  - RESPONSE: We look at the wind profile, energy provided, what thermal generation it displaces, etc. This is the approach we have taken to Crossroads and other wind benefit analyses.
- Is it an economic analysis?
  - RESPONSE: Yes, we will add any amount that shows benefit. It may be more or less than the 255 MW.
- When you calculate your wind % do you include PPA and owned?
  - RESPONSE: Yes.
- Is the wind capacity added to the denominator of the calculation?
  - RESPONSE: Yes.
- Comment offered that 15% intended to include utility-owned wind to avoid double counting of PPA wind sourced from wind farms located in Oklahoma.
- Wind producers are reporting their own per OCC direction.
  - RESPONSE: OGE will clarify with producers and OCC, and may revisit calculation for IRP.
- By 2015, the goal is for 15% of actual generation to be from wind?
  - RESPONSE: It's actually 15% renewable, which 25% of the 15% can be DSM. Thus wind accounts for approximately 12-13% of the goal.
- What resources will be displaced by that wind?
  - RESPONSE: It's a mix of coal and gas. About 50% of wind production is at night, when we generally run coal plants. We run gas plants to follow load during the day. Fuel prices and other assumptions vary the percentages of each. The SPP market will affect this as well.
- Is OGE or SPP doing a wind integration study?
  - RESPONSE: The SPP retained Charles River to perform a wind integration study that is available on the SPP website.



OG&E Comments:

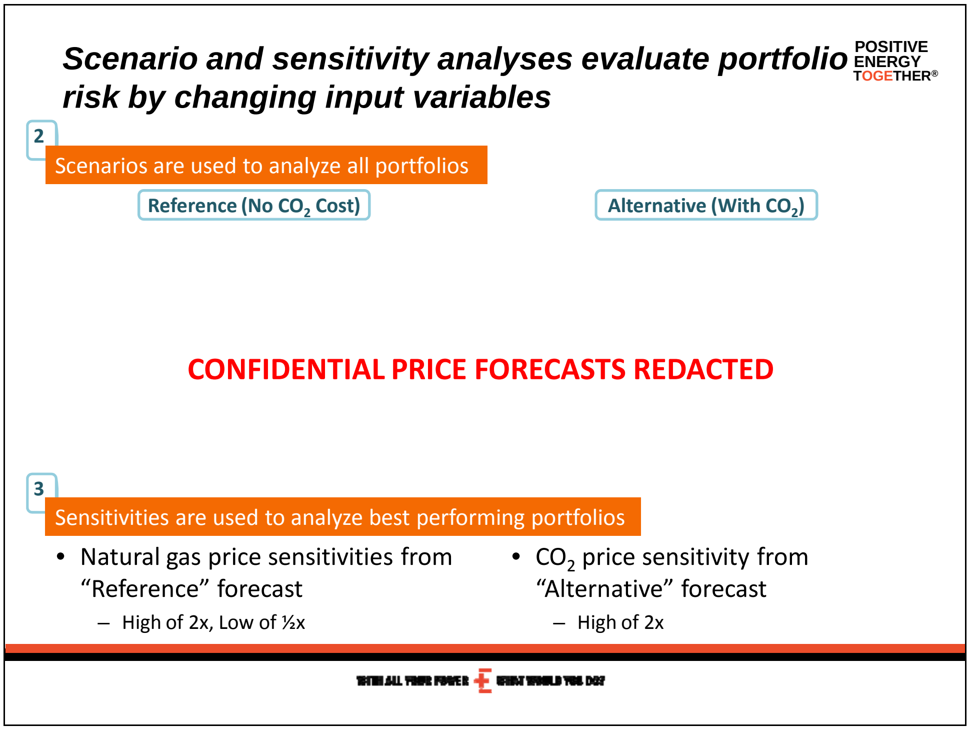
- We are going to look at the addition of wind options in 3 ways: no wind, wind in 2012 before the PTC expires and wind in 2013 after the PTC expires.
- We are going to consider a number of environmental options as indicated in the slide.

Questions:

- Are the natural gas price scenarios an OGE forecast and from a third party?
  - RESPONSE: Yes, these will be discussed on the next slide.
- Why are you only looking at 2012 and 2013 for wind additions?
  - RESPONSE: We are looking at no wind, wind just before termination of PTCs (end of 2012), and after termination of PTCs (start of 2013).
- Other than that, you won't be looking at any other wind?
  - RESPONSE: That's correct.
- Is the 2018 the deadline for environmental compliance?
  - RESPONSE: Because we don't know now what the deadline will be, we have assumed for modeling purposes that 2018 is the deadline for compliance. We do not expect that the results would vary much if that date is moved forward or backward a year or two.
- The last IRP had about 1200MW of wind beyond 2015, now we're at 255. What has changed?
  - RESPONSE: One significant change is the increased uncertainty regarding the prospects for environmental legislation. In the last IRP we assumed that we had to hit hard CO2 caps that wind helped OG&E to meet. Also, feedback from interveners after our last IRP led us to evaluate only the next increment of wind.
- Have you thought about plugging in wind as an option and letting the model select?

- RESPONSE: We do not have a modeling tool to do that and we do not believe that existing available tools handle wind appropriately. They don't model wind very well as they use typical week analysis, not hourly. We use the PCI GenTrader tool that is an hourly analysis. We believe that our approach is superior.

- Are you saying that the model will not optimize timing and quantity of wind selection?
  - RESPONSE: Yes, it does not do that. We believe our method is the correct way to do this.
- Under the SIP, is BART low sulfur coal, or low sulfur coal with a combination of wind and conversion to NG?
  - RESPONSE: It's the addition of Low NOx Burners on coal plants and Seminole, which we plan to do. The SIP was Low sulfur coal, and a cap on the production from the units to limit production.
- Does one of the hybrids represent the State Implementation Plan ("SIP")?
  - RESPONSE: No, the benchmark represents the SIP, the hybrids are planned for future regulations such as the MACT HAPS rule.
- What are the regional haze caps?
  - RESPONSE: They are presented in the SIP.
- In the new resource options, are you using all CC or all CT?
  - RESPONSE: Yes, initially. We may look at a mix later on, but not in the first pass.
- Is your benchmark consistent with the SIP?
  - RESPONSE: Yes, those caps are in place.
- The scrub option in 2018? 4 units?
  - RESPONSE: Yes, 2018, and all 5 units. Only 4 units fall under regional haze, but we are assuming that new regulations would require scrubbing all 5 of our units.
- None of these options will be the alternative options from the SIP (options 2 or 3)? The option to have reduced output and scrub later on around 2026 seems like a reasonable option.
  - RESPONSE: No, we believe those are covered by our portfolios. We don't believe the answers are materially different if you look at scrubbing 4 or 5 units.
- With respect to the potential of scrubbers or MACT being required/implemented – has OG&E analyzed the effects of the construction of all that equipment on reliability or reserve margin (specifically the amount of time they might be offline)?
  - RESPONSE: Yes, the equipment can be built alongside an online unit, requiring the units to be offline for a short period of time.
- If EPA imposes a Federal Implementation Plan ("FIP"), can OG&E still get the units built in time?
  - RESPONSE: We assume EPA will allow a reasonable amount of time to get the equipment installed.



OG&E Comments:

- Risk will be considered through both scenario analysis and sensitivity analysis. May include stochastic analysis.
- Two separate futures or scenarios will be considered
  - Reference case is what we believe NG prices will be, and has $0 CO2 cost for the entire study period
  - The Alternative scenario assumes a CO2 tax
  - Our coal costs are from an internal forecast. Coal cost increases are primarily driven by coal transportation cost increases.
- Sensitivity analysis will be performed changing 1 variable while hold others constant
- Stochastic analysis allows for a change of a number of variables at the same time. While we perform the stochastic analyses as an extra step, they are generally not the primary factor in identifying the best portfolio(s) as they depend on assumptions that are subject to considerable uncertainty including correlation relationships among key inputs.

Questions:

- How realistic do you think carbon legislation is passing in the next few years?
  - RESPONSE: We certainly monitor that situation closely. We believe it's a plausible future that should be analyzed in the Alternative scenario.
- Any idea what other utilities are now doing for planning for carbon costs in IRPs?
  - RESPONSE: We do participate in meetings with other utilities where this issue is discussed in the planning context. Many other utilities use Ventyx as well. Many others still evaluate CO2 legislation, and I believe it would be negligent to not analyze that impact.

- The gas forecast seems high, why is that?
    - RESPONSE: Ventyx uses comprehensive models to determine their gas forecast. We can't speak to how they got that number.
- We can assume these are the prices in the scenarios?
    - RESPONSE: Yes

Regional Transmission Expansion costs will be reflected in the interim IRP

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2010 STEP Projects

Project Type	Cost, $ in Millions
Balanced Portfolio	825
Priority Projects	1,418
Regional Reliability	1,463
Transmission Service	549
Other	605
Total E&C Cost	4,860

Benefits of EHV Expansion
- *Production Cost savings through IMP as least cost resources are deliverable throughout region*
- *Increased West-to-East transfer of wind resources*
- *Increased reliability*

WITH ALL YOUR POWER E WHAT WOULD YOU DO?

OG&E Comments:

- SPP is responsible for transmission planning
- OG&E is responsible for roughly 13% of SPP's total revenue requirement

Questions:

- The last wind addition about tapped out the transmission capacity, is the 255 going to be deliverable?
    - RESPONSE: That is correct. Limitations will be relieved in 2014 as transmission projects are complete. There are other suitable wind locations in Oklahoma that can provide the 255 MW and are not transmission constrained.
- What will you assume about transmission for them?
    - RESPONSE: For a proxy, we are going to pick two locations and do transmission studies to determine interconnection feasibility and cost.
- Will you estimate OG&E's share of the $4.8B?
    - RESPONSE: Yes, we will include in the plan an estimated annual revenue requirement of SPP transmission expansion.

The impact of the SPP market on the best options will be analyzed

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- The SPP is transitioning to an Integrated Marketplace (IMP)
  - Consolidated Balancing Authority (CBA)
  - Day-Ahead energy and ancillary services markets
- Best plans in IRP will be evaluated in this new marketplace

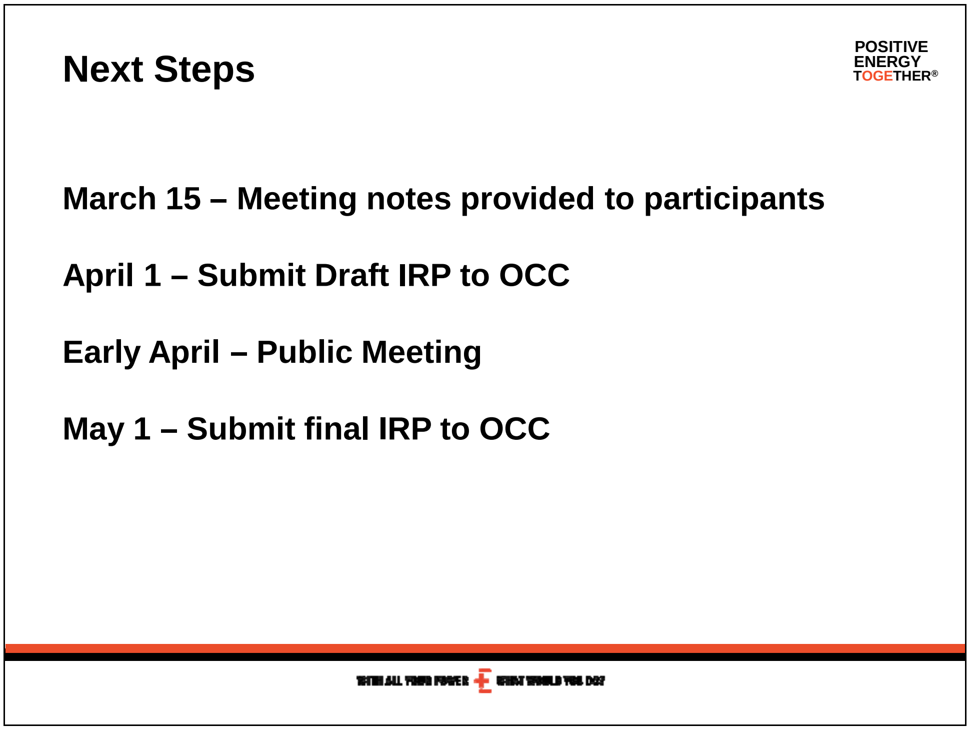
OG&E Comments:

- OGE has been participating in the development of the SPP market, assumed to start in 2015.
- PROMOD is used to model the SPP market, which requires us to make assumptions regarding the actions of other SPP members.
- OGE does not believe that introduction of the SPP market will have a drastic impact due to the fact that OGE units are representative of the average in the SPP.

Questions:

- Is it a security constrained economic dispatch?
  - RESPONSE: Yes, transmission limits are considered. The significant EHV expansion will greatly reduce transmission limitations.
- You said they're not huge impacts, but do they justify transmission projects?
  - RESPONSE: Yes, they have been justified by SPP on a regional level.
- Will only the energy market be modeled?
  - RESPONSE: Yes, there are no plans for a capacity market in the SPP.
- Are you relying on SPP or OG&E studies to conclude that OG&E's benefits will not be significant?
  - RESPONSE: Both. The SPP showed a net savings to OGE of $20M over the next 10 years.
- Do those SPP studies show any of your units not running?
  - RESPONSE: No, all our units will be utilized, but SPP studies project that some of our units will run less. However, all our units will still be needed to meet capacity requirements.
  - Would you consider retiring these units if they are not going to be run for the next 6 or 7 years?

- RESPONSE: Even though units may not provide energy, they still provide capacity which has a value.
- Have you looked at making improvements so they would run?
  - RESPONSE: Yes, we are looking at that.



Part 2: Stakeholder Feedback

Stakeholders provided the following feedback to OGE:

1. Wind – The two wind options (2012 and 2013) may be too limiting. It would be informative to know how an additional wind option in a later year (2015 or toward the end of the decade) would be evaluated. OG&E should employ competitive bidding for new wind resources.

2. Environmental Impact Modeling – Appear to be modeling only a cap and trade approach. Might consider evaluating control approaches to environmental regulation. Should expand horizon of potential environmental regulation beyond the current decade.

3. Portfolios – OG&E is specifying that the model select either CCs or CTs to meet capacity needs. Combinations of CCs and CTs should also be considered given the amount of wind in OG&E's portfolio. Consideration of natural gas plants should reflect both capital costs and operational characteristics. OG&E should use its IRP modeling capability to perform studies of real operational issues that are on the table from time to time (between required IRP submittals) including actual Regional Haze options that are being considered.

4. Natural Gas Prices – Gas price forecasts appear to be high. The IRP should expand on how these forecasts were derived and consider incorporating other sources for natural gas price forecasts as well.

5. SPP Day 2 Market – Performing the SPP market analysis based only on the portfolios that perform best in the initial analysis may mean that certain portfolios that are best may not make it to the SPP Day 2 market analysis. Should consider performing analysis on all portfolios reflecting Day 2 Market.

6. Presentation of Results – It would be informative to see the average annual revenue requirement impacts and not only the 30-year Net Present Value revenue requirements. In general, greater clarity on impacts to customers would be beneficial.

7. SPP Transmission Expansion Plan ("STEP")– Concern expressed that it is difficult to determine if elements of the STEP provide economic benefits to OG&E customers. Question raised as to whether OG&E can provide insights using its IRP analyses.

8. Unit Retirement Analysis – OG&E should evaluate retiring units that are not expected to run for several years after introduction of the SPP Day 2 energy market.

9. Long Term Natural Gas Contracting – IRP should identify impacts on OG&E's natural gas requirements under various portfolios to be considered in developing its long-term gas contracting plans.

10. Coal Plant Operations – Concern expressed that coal plant performance has declined recently and whether these issues are attributable to environmental constraints and are likely to continue and be reflected in the IRP modeling. Preference expressed for a discussion of this issue in the IRP submittal.

In closing, OG&E thanked the participants for their questions and feedback and indicated that the IRP team would get together and review each element of feedback and determine what modifications to its approach should be made. While not commenting extensively on the feedback, OG&E did note that it had spent a fair amount of time discussing the best approach to modeling of the SPP impacts and arrived at its current approach based on several factors including the need for extensive assumptions regarding other SPP market participants and complexity of running the hourly PROMOD model. OG&E also indicated that the IRP will provide estimates of cost impacts of various planning portfolios but also noted actual cost impacts will not be identified until OG&E makes a request for approval of a specific resource decision at the OCC.