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OG&E ENERGY
INTEGRATED RESOURCE PLAN

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Table of Contents

EXECUTIVE SUMMARY **1**

I. INTRODUCTION **I-1**

II. LOAD FORECAST AND CALCULATION OF CAPACITY NEEDS **II-1**

A. OG&E'S SERVICE TERRITORY II-1
B. ECONOMIC OUTLOOK II-2
1. *Oklahoma Economic Outlook* *II-3*
2. *Arkansas Economic Outlook* *II-4*
C. FORECAST OF ENERGY SALES AND PEAK DEMAND II-4
1. *Energy Sales Forecast* *II-5*
2. *Peak Demand Forecast* *II-5*
a. Peak Demand Forecasting Methodology II-5
b. Forecasting Peak Loads II-7
c. Expected Loads by Weather Probability II-8
d. Total Peak Demand, Including Wholesale Contracts II-9
3. *Low and High-Growth Cases* *II-10*
D. CALCULATION OF CAPACITY NEEDS II-12
1. *Required Reserve Margins* *II-12*
2. *Base Case - Capacity Margins* *II-13*
3. *Low and High-Growth Cases* *II-14*

III. OG&E'S RESOURCE PORTFOLIO AND REGULATORY / LEGISLATIVE DRIVERSIII-1

A. EXISTING GENERATION AND DSM RESOURCES III-1
1. *Retirement of Generation Facilities* *III-5*
2. *Enid Improvements* *III-5*
3. *Qualifying Facilities Purchase Power Contracts* *III-5*
4. *Wind Generation* *III-5*
5. *Existing DSM* *III-6*
B. COAL AND NATURAL GAS SUPPLIES III-6
1. *Coal Supply and Transportation* *III-7*
2. *Natural Gas Supply and Transportation* *III-7*
C. TRANSMISSION CAPABILITIES AND EXPANSION PLANS III-8
1. *Current Transmission System Adequacy* *III-9*
2. *SPP Regional Transmission Organization (RTO) Expansion Plans* *III-9*
a. Reliability Upgrades III-9
b. Economic Upgrades III-10
3. *FERC Transmission Considerations for Incremental Generation* *III-11*
D. SPP AND REGIONAL ELECTRICITY MARKETS III-12
1. *SPP Overview* *III-12*
2. *SPP Market Demand, Supply, and Prices* *III-14*
3. *New SPP Market Services* *III-17*
4. *Transmission Service and System Expansion* *III-19*
E. REGULATORY AND LEGISLATIVE DRIVERS III-23
1. *State Utility Commissions* *III-24*
2. *FERC* *III-24*
3. *NERC* *III-24*
4. *EPACT 2005* *III-25*
5. *Environmental Regulation* *III-25*
a. Sulfur Dioxide III-26
b. Nitrogen Dioxide III-26
c. ODEQ Permitting III-27
d. Mercury III-27
e. Ambient Ozone, Fine Particulates and Visibility III-27
f. Carbon Dioxide III-28
g. Water III-29

IV. ANALYSIS OF OG&E'S RESOURCE OPTIONS **IV-1**

Table of Contents

A. MODELING APPROACH AND INPUTS IV-1
1. *Specification of Resource Alternatives* *IV-2*
a. Resources Evaluated Using CEM and PAR IV-3
b. Model Input Assumptions IV-4
c. Transmission Cost Assumptions IV-5
2. *Natural Gas and Coal Price Assumptions* *IV-9*
a. Natural Gas Prices IV-9
b. Coal Prices IV-9
c. Fuels Forecast IV-10
3. *Environmental Regulation Impact on the Resource Plan* *IV-12*
B. SCREENING ANALYSIS USING CEM IV-12
1. *Base Case Analysis Using CEM* *IV-12*
2. *Alternative Planning Case Analyses Using CEM* *IV-15*
a. Planning Case Design IV-15
b. *Changes in the Optimal Portfolio under Alternative Cases* IV-18
C. ANALYSIS OF RISK AND THE USE OF PAR IV-21
1. *Risk Factors and Distribution Curves* *IV-22*
a. Retail Load Risk IV-22
b. Natural Gas Price Risk IV-23
c. Coal Price Risk IV-24
d. Environmental Cost Risk IV-24
2. *Stochastic Risk Assessment Using PAR* *IV-25*

V. RESOURCE STRATEGY AND IMPLEMENTATION PLAN V-1

A. RESOURCE STRATEGY V-1
B. IMPLEMENTATION PLAN V-2

APPENDIX A – FUEL PROCUREMENT / RISK MANAGEMENT PLAN 1

APPENDIX B – 2005 LOAD FORECAST 1

APPENDIX C – PURCHASED POWER PROCUREMENT PLAN 1

APPENDIX D – PROPOSED RFPS FOR SOLICITING NEW RESOURCES 1

APPENDIX E – TRANSMISSION SYSTEM ANALYSIS FOR NEW GENERATION RESOURCES1

APPENDIX F – DESCRIPTION OF CERA SCENARIOS 1

***APPENDIX G – ECONOMIC INPUT DATA* 1**

APPENDIX H – GENERATION TECHNOLOGY ASSESSMENT 1

APPENDIX I – CEM DESCRIPTION AND INPUT DATA 1

A. DESCRIPTION AND USAGE 1
B. OPTIMIZATION ALGORITHM 1
C. INPUT DATA 2

APPENDIX J – PAR INPUT DATA 1

APPENDIX K – TEN-YEAR TRANSMISSION CONTINGENCY STUDY 1

List of Figures

FIGURE II-1 OG&E SERVICE TERRITORY AND GENERATION PLANT LOCATIONS II-1
FIGURE II-2 PEAK DEMAND MODEL FORECASTS BY WEATHER PROBABILITY (EXCLUDES WHOLESALE SALES) II-9
FIGURE II-3 SCENARIO PEAK DEMAND VARIATION (AVERAGE GROWTH IN %/YR) II-11
FIGURE II-4 SCENARIO ENERGY FORECAST VARIATION (AVERAGE GROWTH IN %/YR) II-12
FIGURE III-1 2005 OG&E GENERATION AND PPA CAPACITY (MW) III-2
FIGURE III-2 OG&E 2005 LOAD RESPONSIBILITY DISTRIBUTION CURVE III-4
FIGURE III-3 SPP GEOGRAPHICAL AREA III-13
FIGURE III-4 CURRENT ON-LINE SPP GENERATION CAPACITY BY FUEL TYPE III-15
FIGURE III-5 AVERAGE ELECTRICITY PRICES IN THE SPP FROM 2001 TO 2005 .... III-17
FIGURE III-6 MONTHLY SPP CONFIRMED TRANSMISSION SERVICE REQUESTS (FREQUENCY) FROM 2004 TO 2005 .... III-21
FIGURE III-7 MONTHLY SPP CONFIRMED TRANSMISSION SERVICE REQUESTS (MWH) FROM 2004 TO 2005 .... III-22
FIGURE IV-1 2006 IRP ANALYSIS PROCESS IV-2
FIGURE IV-2 HISTORICAL OG&E FUEL PRICES IV-11
FIGURE IV-3 PLANNING CASES IV-15
FIGURE IV-4 ALTERNATIVE CASE PEAK DEMAND VARIATION (AVERAGE GROWTH IN %/YR) IV-17
FIGURE IV-5 ALTERNATIVE CASE ENERGY FORECAST VARIATION (AVERAGE GROWTH IN %/YR) IV-17
FIGURE IV-6 ALTERNATIVE CASE NATURAL GAS PRICES (REAL 2006 $) IV-18
FIGURE IV-7 ALTERNATIVE CASE SO_2 EMISSIONS COSTS (REAL 2006 $) IV-18
FIGURE IV-8 ALTERNATE CASE NO_X EMISSIONS COSTS (REAL 2006 $) IV-18
FIGURE IV-9 ALTERNATE CASE HG EMISSIONS COSTS (REAL 2006 $) IV-18
FIGURE IV-10 ALTERNATE CASE CO_2 EMISSIONS COSTS (REAL 2006 $) IV-18
FIGURE IV-11 PEAK DEMAND STOCHASTIC RANGE IV-22
FIGURE IV-12 30-YEAR COMPOUND AVERAGE GROWTH RATE IN LOAD IV-23
FIGURE IV-13 NATURAL GAS PRICE DISTRIBUTION (2006 $/MMBTU) IV-23
FIGURE IV-14 NATURAL GAS PRICES STOCHASTIC RANGE IV-23
FIGURE IV-15 COAL PRICE DISTRIBUTION (2006 $/MMBTU) IV-24
FIGURE IV-16 COAL PRICES STOCHASTIC RANGE IV-24
FIGURE IV-17 CO_2 COSTS STOCHASTIC RANGE IV-25
FIGURE IV-18 HG COSTS STOCHASTIC RANGE IV-25
FIGURE IV-19 CUMULATIVE PROBABILITY OF REVENUE REQUIREMENTS IV-26
FIGURE IV-20 NPVRR CUMULATIVE PROBABILITY DISTRIBUTION FOR ALL CASES IV-27
FIGURE IV-21 NPVRR CUMULATIVE PROBABILITY DISTRIBUTION FOR BASE AND SENSITIVITY CASES IV-27

List of Tables

TABLE ES-1 FIVE-YEAR ACTION PLAN 3
TABLE II-1 ECONOMIC DRIVERS' GROWTH RATES, 2005 FORECAST II-5
TABLE II-2 2005 ENERGY SALES FORECAST II-5
TABLE II-3 WEATHER STATION WEIGHTS II-7
TABLE II-4 PROBABILITY OF OCCURRENCE II-8
TABLE II-5 PEAK DEMAND MODEL FORECASTS BY WEATHER PROBABILITY (EXCLUDES FERC SALES) .. II-8
TABLE II-6 ANNUAL PERCENT INCREASE BY CUSTOMER CLASS II-10
TABLE II-7 ACTUAL AND PROJECTED TOTAL PEAK DEMANDS II-10
TABLE II-8 CAPACITY PLANNING MARGINS – BASE CASE SCENARIO II-14
TABLE II-9 BASE, LOW, AND HIGH GROWTH PEAK DEMAND FORECASTS II-15
TABLE III-1 OG&E-OWNED GENERATING FACILITIES (DETAILED) III-4
TABLE III-2 QUALIFYING FACILITIES III-5
TABLE III-3 BENEFIT-COST RATIO BASED ON 10-YEAR SAVINGS III-11
TABLE III-4 SPP BASIC FACTS III-13
TABLE III-5 MONTHLY PEAK ELECTRIC ENERGY DEMAND (MW) FOR SPP III-14
TABLE III-6 CURRENT ON-LINE GENERATION CAPACITY BY CONTROL AREA III-15
TABLE III-7 STATUS AND CAPACITY OF ACTIVE GENERATION INTERCONNECTION REQUESTS III-16
TABLE IV-1 NEW CAPACITY RESOURCE - SUMMARY OF INPUT DATA IV-5
TABLE IV-2 SITES FOR FUTURE GENERATION RESOURCES IV-6
TABLE IV-3 WIND BLOCKS - NETWORK CONSTRAINTS ESTIMATED COST IV-8
TABLE IV-4 TOTAL ESTIMATED COST FOR ALL EXPANSION PLANS IV-8
TABLE IV-5 FUEL FORECAST 2007 - 2036 (REAL 2006 $) IV-12
TABLE IV-6 BASE CASE ASSUMPTIONS IV-12
TABLE IV-7 CAPACITY EXPANSION STRATEGIES (10 YEARS) – BASE CASE SCENARIO IV-14
TABLE IV-8 MAJOR CASE ASSUMPTIONS IV-16
TABLE IV-9 CAPACITY EXPANSION STRATEGIES (10 YEARS) – ALTERNATIVE CASES IV-20
TABLE IV-10 RISK CHARACTERIZATION IV-21
TABLE V-1 FIVE-YEAR ACTION PLAN V-2
TABLE G-1 ECONOMIC INPUT DATA 1

Executive Summary

Oklahoma Gas & Electric Company (OG&E) submits this resource plan in compliance with Subchapter 37 of OAC 165:35 that established the Oklahoma Corporation Commission ("OCC" or "Commission") rules governing the preparation and review of electric utility integrated resource plans (the "IRP Rules"). As stated in Section 165:35-37-1:

> "Recognizing the significance of the costs incurred based on resource plans, the Commission believes it is in the best interest of retail customers and the utilities providing regulated retail electric supply to establish regular review of the utilities resource plans to ensure that the utilities' resource planning and resulting investment are reasonably and prudently conducted and that the overall cost of power supply to retail customers is fair and reasonable."

Contracting of electric supply to meet an electric utility's public service obligations has always been a very complex matter, and is becoming more so, due to ever evolving market forces. This complexity derives from many interrelated factors including the impact of national and regional business cycles on the demand for electricity, increasingly costly, volatile and uncertain fuel prices, evolving wholesale electricity markets, emergence of independent power producers, and potential changes in state and federal governmental regulation, including changing environmental regulations.

This resource plan presents a snapshot of these challenges and opportunities for OG&E as of October 1, 2006. 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 at the lowest reasonable cost. In reality, OG&E is continually evaluating resource alternatives in response to constantly evolving conditions and opportunities.

The development of an IRP begins with the establishment of specific planning criteria or guidelines. OG&E planning criteria are as follows:

1. Achieve a portfolio that ensures reliability of supply and reasonable cost while mitigating market risks in a cost-effective manner;
2. Provide resource "optionality" regardless of source or type on reasonable terms to respond to changing demand and supply conditions;
3. Provide for diversity of supply and demand side resources with respect to technology, fuel source, and contract terms to minimize exposure to unanticipated market and regulatory developments and provide for greater price stability;
4. Satisfy anticipated environmental regulations in a cost-effective manner and reflect the potential for stricter environmental regulations in the future; and

5. Maintain or enhance the financial integrity of OG&E in order to finance preferred significant generation or transmission investments on reasonable terms.

The key output of OG&E's IRP is the Five-Year Action Plan. This plan is based in part on the results of resource optimization software which are utilized as a basis for comparing supply options in order to determine which option or options will provide reliable, reasonably priced supplies needed to meet OG&E's customers' electric demands into the future. The resource optimization software facilitates explicit modeling of uncertainties which impact supply decisions, including demand growth, fuel prices, and environmental regulations. The optimization models project the least cost resource plan over a ten-year horizon; and they also examine the impact on the resource plan of uncertainties. This process begins with the determination of an optimal generation portfolio based on a "Base Case" set of assumptions.

Risk that is attributable to uncertainties is incorporated into the modeling in two ways. First, scenarios and sensitivities are created to test the impact on the optimal portfolio of alternative assumptions. Second, the costs associated with various portfolios are tested by specifying probability distributions around expected values for the key input assumptions.

OG&E's Resource Strategy is ultimately based on the judgment of the Company's utility resource planners and management team using these quantitative results. The IRP also includes a draft implementation plan and timeline that identifies the actions that are required to implement the Resource Strategy, focusing on the first five years ("Five-Year Action Plan").

As shown in Table ES-1, the Five-Year Action Plan differs in several respects from the deterministic modeling based on the set of Base Case assumptions.

Year	**Minimum Incremental Capacity Need (MW)**	**Modeling Results (Preferred Resource)**	**Five-Year Action Plan**
2007	46	48 MW Enid Plant	• Repair and Upgrade Enid • Request for Proposal (RFP) for Economy Energy for 2007 • Complete Demand Side Management (DSM) Study • Review Existing Contracts
2008	120	100 MW Peaker; 45 MW Peaker	• Results of RFP for Capacity and/or Energy for 2008 - 2010 • Update IRP • Review Existing Contracts

Year	Minimum Incremental Capacity Need (MW)	Modeling Results (Preferred Resource)	Five-Year Action Plan
2009	90	100 MW Peaker	• Results of RFP for Capacity and/or Energy for 2008 – 2010 • Review Existing Contracts
2010	130	100 MW Peaker	• Results of RFP for Capacity and/or Energy for 2008 – 2010 • Issue RFP for Capacity and/or Energy for Future Years • Review Existing Contracts
2011	90	400 MW Joint Coal Baseload Unit	• Commercial Operation of 400 MW Coal Plant • Results of 2010 RFP • Review Existing Contracts

Table ES-1 Five-Year Action Plan

Although not specified in this table due to the lack of dependable, reliable capacity, wind generation resources will continue to be pursued throughout the 10-year planning horizon.

Uncertainty and risk in the modeling results have been considered in four ways.

First, there is a considerable uncertainty attributable to deviations in the short-term load forecast. The model results proposed peaking units over the 2008-2010 timeframe. OG&E believes that an approach that considers purchased power agreements (PPA) along with construction options is appropriate. Therefore, the Five-Year Action Plan reflects a series of PPA contracts based on RFPs to be issued this fall. The RFPs will seek to determine if PPAs can be acquired on reasonable terms.

Second, OG&E is currently conducting a study to develop a greater understanding of the potential for Demand Side Management (DSM) programs as an incremental resource. OG&E has performed a preliminary analysis of the value of DSM based on Global Energy's Capacity Expansion Module (CEM), but further work is required to establish the technical potential of this resource. *This study will be completed in 2007. If* DSM proves to be a viable and meaningful source for reducing the need for incremental capacity, DSM will provide some protection against higher fuel prices.

Third, wind power also provides a hedge against higher fuel prices. Thus, OG&E will continue to pursue opportunities to acquire or develop incremental wind generation. These investments will likely come at a higher capital cost (and lower capacity value) than more traditional generation alternatives, but they do serve to mitigate risk. This option will continue to be evaluated as wind technology improves.

Finally, OG&E will submit an updated IRP in the fall of 2008. It is anticipated at this time that in 2009 OG&E will issue an RFP for baseload capacity providing sufficient lead time for OG&E or a third party to construct a baseload unit to be in service by 2014. A self-build option could compete against third-party options in this RFP.

I. Introduction

OG&E submits this IRP pursuant to Title 165: OCC, Chapter 35 Electric Utility Rules, and Subchapter 37 Integrated Resource Plan, which directs each utility to submit a plan on October 1, 2006.

OG&E's IRP satisfies the filing requirements established in Title 165:35-37-6 and includes:

1. An electric demand and energy forecast;
2. A forecast of capacity and energy contributions from existing and committed supply- and demand-side resources;
3. A description of transmission capabilities and needs covering the forecast period;
4. An assessment of the need for additional resources;
5. A description of the supply, demand-side and transmission options available to the utility to address the identified needs;
6. A fuel procurement plan, purchased power procurement plan, and risk management plan;
7. An action plan identifying the near-term (i.e., across the first five (5) years) actions that the utility proposes to take to implement its proposed resource plan;
8. Any proposed RFP(s), supporting documentation, and bid evaluation procedures by which the utility intends to solicit and evaluate new resources; and
9. A technical appendix for the data, assumptions and descriptions of models needed to understand the derivation of the resource plan.

The Executive Summary provides an overview of the objectives of the IRP, OG&E's resource planning objectives, the analyses that have been performed, and the development of what is referred to as the "Resource Strategy".

Following this Introduction, Section II presents an overview of OG&E, the regional economy, the capacity and energy forecast, as well as the determination of needs to be met with a combination of incremental resources and resource retirements. Section III presents the existing resource portfolio and regulatory considerations that have a potential impact on the IRP. Section IV presents a detailed discussion of the modeling efforts that support the development of the Resource Strategy, including identification of potential resource options to meet forecasted needs. The report concludes with a discussion of the Resource Strategy in Section V.

More detailed information supporting the plan are presented in Appendices A through K, including supporting data and assumptions, descriptions of the two optimization models that were used, a more detailed discussion of the load forecast, and draft implementation documents including a fuel procurement and risk management plan and a draft of a 2006

RFP for Peaking Supplies. A more detailed discussion of transmission capabilities is also presented in an appendix.

II. Load Forecast and Calculation of Capacity Needs

OG&E's 2005 Load Forecast, attached in Appendix B, is the basis for the discussion in this section of the IRP. OG&E's demand and energy forecast is finalized each year in August or September based on the prior year's economic outlooks by Oklahoma State University (OSU) and University of Arkansas Little Rock (UALR). Due to the requirement of submitting the IRP by September 1, 2006, the IRP process had to begin prior to the 2006 Load Forecast completion. However, preliminary results from the 2006 Load Forecast do not indicate that there will be significant changes from the 2005 forecast.

A. OG&E's Service Territory

OG&E serves approximately 750,000 retail customers in Oklahoma and western Arkansas and a number of wholesale customers throughout the region. As shown in Figure II-1, OG&E's service area covers 269 communities and their contiguous rural and suburban areas. The service area has an estimated population of 2.0 million and covers approximately 30,000 square miles in Oklahoma and western Arkansas; including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas. Of the 269 communities served, 243 are located in Oklahoma and 26 in Arkansas. Approximately 88 percent of total electric operating revenues for the year ended December 31, 2005, were derived from sales in Oklahoma and the remainder from sales in Arkansas. Retail plus wholesale sales in the state of Oklahoma were 22,474,998 MWh and in the state of Arkansas the retail plus wholesale sales were 3,725,017 MWh.

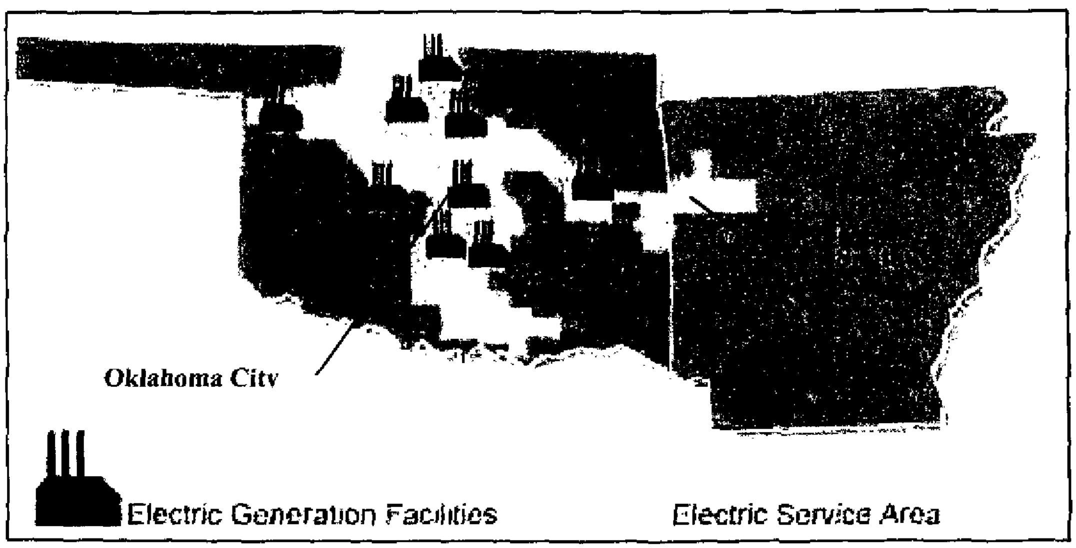


Figure II-1 OG&E Service Territory and Generation Plant Locations

OG&E's system control area peak demand as reported by the system dispatcher during 2006 was approximately 6,472 MW on August 10, 2006. This includes an estimated 313 MW of load attributable to Oklahoma Municipal Power Authority (OMPA) within the control area. OG&E's load responsibility peak demand was approximately 6,115 MW on August 10, 2006.

Energy sales have grown faster than peak demand over the past two years. OG&E delivered approximately 26.1 million MWh sales in 2005 as compared to approximately 24.8 million in 2004 and 25.1 million in 2003. MWh sales to OG&E's retail customers ("system sales") increased approximately 5.3 percent in 2005, primarily due to warmer weather during 2005. Sales to other utilities and power marketers ("off-system sales") remained relatively flat in 2005. Variances in off-system sales are due in large part to the changing supply and demand needs on OG&E's generation system and the market for off-system sales.

B. Economic Outlook

OG&E's 10-year load forecast is developed using econometric forecast models that are based on historical relationships between energy sales and economic variables that include independently produced service area economic and population growth forecasts. This 10-year forecast is straight-line trended to estimate the values for a 30-year model. Since 2001, OG&E has relied on historical and economic variables (drivers) over the 10-year forecast period from the following two sources:

- The Oklahoma Economic Outlook, prepared by the OSU College of Business Administration, Department of Economics and Legal Studies; and
- The Arkansas Economic Outlook, prepared by the UALR Institute for Economic Advancement.

The OSU and UALR forecasts are derived from a combination of national economic forecasts prepared by Global Insight and their own state and local economic models. Both the Oklahoma Economic Outlook and the Arkansas Economic Outlook were produced in November 2004, and OSU developed a mid-2005 outlook update in June 2004.

Economic output has continued to expand at an impressive rate since the 2001 recession, although slowing in 2006 due in part to higher energy costs and interest rates. Real US Gross Domestic Product (GDP) in 2004 was 4.5%, but is expected to slow to an intermediate-term real growth rate of 3%. The national average price of regular unleaded gasoline hit an all time monthly high in May at $2.95 per gallon, while the Federal Reserve pushed the Federal Funds rate from 1.0% in mid-2004 to 5.25% in mid-2006. These forces appear likely to continue to constrain the rate of economic growth in 2006 and 2007.

In addition, the fundamentals in the national housing market have clearly weakened as 30-year fixed mortgage rates above 6.5% are having a measurable impact on buyers. The number of new homes sold in 2006 is nearly 10% behind last year's pace through May. Both average and median home sale prices peaked in early 2006 and are falling. National housing starts are also off 10% since January.

1. Oklahoma Economic Outlook

Oklahoma is also experiencing a slower growth rate in 2006. The Oklahoma unemployment rate appears to have bottomed at about 4% in the first half of 2006, falling from a high of nearly 6% in 2003. The bottom set in the previous expansion was around 3% in 2000.

Although higher fuel prices have a slowing effect on the national economy, OSU believes that the state's oil and gas sector has an offsetting positive impact on the Oklahoma economy. These offsetting factors include oil and gas drilling and production, severance tax revenue, oil field equipment production, oil field services, and financial and legal services. Notably, much of this activity is occurring in the state's rural areas.

OSU projects that Real Gross State Product (GSP) is expected to grow in 2006 with an estimated 2.7% increase, down modestly from the 2005 growth rate. The latest personal income release suggests that the state is maintaining recent income gains relative to the nation. State per capita personal income relative to the national average has jumped from 81% to 85% since 2000. The Oklahoma City per capita income has increased from 89% of the national level to a forecasted 94% in 2006.

OSU projects that Oklahoma will add 17,300 new jobs in 2006, after accounting for a slowdown in manufacturing employment led by plant shut-downs by General Motors, resulting in a loss of approximately 13,400 jobs, and job losses at Bridgestone/Firestone. The majority of the new jobs are expected to be created in Oklahoma City (10,500). Tulsa is projected to continue to build upon the strong employment growth that it exhibited in 2005 with the addition of approximately 3,500 jobs. The strong job growth in Tulsa in 2005 and the expected growth in 2006 indicate that Tulsa appears to be rebounding from the poor economic performance that it has exhibited over the past few years.

Oklahoma City continues to outperform the rest of the state. The Oklahoma City metro area is expected to create approximately 10,500 jobs in 2006, expanding at a 1.9% rate. This exceeds both the 1.6% rate expected for the state and the 1.5% rate for the nation. Anticipated job growth in the Oklahoma City area is broad based, with growth in nearly all industry sectors, except for manufacturing.

The largest growth in employment is expected in the Professional and Business Services sector, where it is estimated that 2,340 new jobs will be created in 2006. Education and Health Services are also expecting strong gains with the addition of 1,500 jobs. Employment in the state and local government is expected to show a slight decrease in gains compared to 2005 with the addition of 1,020 jobs. A slowdown is also expected in the leisure and hospitality industries, where 1,030 new jobs are expected to be created. Real income growth in the Oklahoma City area is estimated to have increased 7.2% in 2005 and is expected to continue to grow strongly at a 6.6% pace in 2006.

2. Arkansas Economic Outlook

Gains in Arkansas' economy are slightly below the national experience due to lack of local competitive advantages. The outlook for Arkansas' economy is similar to the state of Oklahoma. UALR expects the economy to slow somewhat. Real income growth is forecasted to decline from nearly 3.5% in 2004 and 2005 to just over 3% in 2006 and 2007. Similarly, real GSP growth is expected to fall from about 4% in 2004 and 2005 to just over 3% in 2006 and 2007.

Sector gains in manufacturing have been limited to rebound in production and order rates, while employment gains remain illusory. No net employment gains are expected in this forecast for either the durable goods or nondurable goods sectors. A major change in export growth or new industry development (auto assembly) would be required to alter current expectations.

However, the Arkansas economy continues to benefit from significant business operating rate improvements and gradual employment improvement. Elevated sales and use tax revenue growth at the state and local levels points to increased business spending and personal consumption driven in part by incremental growth of wage earnings and average weekly work hours.

C. Forecast of Energy Sales and Peak Demand

This section presents OG&E's 2005 load forecast. It describes both the peak demand and energy forecasting models developed by OG&E's Regulatory Affairs and Strategy Department and Quantec, LLC.

The 2005 retail sales forecast utilized the revenue class-based econometric modeling framework that has been in place since 1997. The 2005 load responsibility peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility projections. The hourly modeling approach has been used since the 2000 forecast.

The retail sales 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. Estimated wholesale sales are added to the forecast of retail sales to arrive at a forecast of total OG&E energy sales and peak demand.

Table II-1 below shows key economic drivers and the associated OG&E econometric models they support, as well as historical and forecast growth rates from UALR and OSU.

Economic Drivers and Models	Average Economic Driver Annual Growth Rates		
	1994 - 2004	2005 – 2009	2010 – 2015
Arkansas			
Street lighting: Arkansas Population	1.1%	0.6%	0.6%
Residential: Real Non Farm Income	3.0%	2.2%	1.6%

Economic Drivers and Models	Average Economic Driver Annual Growth Rates		
	1994 - 2004	2005 – 2009	2010 – 2015
Commercial: Real Non Farm Income	3.0%	2.2%	1.6%
Public Authority: Nominal Public Authority GSP	4.8%	4.0%	4.3%
Industrial: Real Gross State Product	3.1%	3.7%	3.5%
Oklahoma			
Street Lighting: OKC Population	1.1%	1.1%	1.1%
Residential: OKC Real Personal Income	3.2%	3.1%	2.6%
Commercial: OKC Real Personal Income	3.2%	3.1%	2.6%
Public Authority: Real Oklahoma GSP	2.7%	2.9%	3.2%
Industrial: Real Oklahoma GSP	2.7%	2.9%	3.2%
Petroleum: U.S. Natural Gas Price	14.8%	1.6%	3.4%

Table II-1 Economic Drivers' Growth Rates, *2005* Forecast

1. Energy Sales Forecast

The 2005 retail energy forecast is based on retail sector-level econometric models representing OG&E's Oklahoma and Arkansas service territories. As noted above, the historical and forecast economic variables (drivers) are derived from the OSU and UALR forecasts.

The final energy forecast, which is summarized in Table II-2 below, includes an estimate of line losses and Federal Energy Regulatory Commission (FERC)-regulated wholesale sales contracts and line losses. The forecast (and actual 2004 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 2.0% over the next decade.

Year	2005 Final Energy Forecast (MWh) *	Energy Growth Rates
2004	26,847,686	
2005	27,546,765	2.6%
2006	28,245,496	2.5%
2007	28,839,705	2.1%
2008	29,385,767	1.9%
2009	29,772,912	1.3%
2010	30,373,873	2.0%
2011	30,835,384	1.5%
2012	31,380,059	1.8%
2013	31,880,670	1.6%
2014	32,581,645	2.2%
2015	33,378,233	2.4%
* Includes FERC sales and line losses		

Table II-2 2005 Energy Sales Forecast

2. Peak Demand Forecast

a. *Peak Demand Forecasting Methodology*

The econometric modeling framework has been in place at OG&E since 2000, with enhancements in 2005. The model consists of 24 separate hourly equations, one for each hour of the day, with separate intercept and slope coefficients. The hourly equations are estimated separately for each month over the May-through-September period.

The dependent variable is normalized load responsibility on the OG&E system, including line losses but net of OMPA Power Sales Agreement (PSA). The independent variables are:

- Cooling degree hours, base 76° F: calculated as the greater of the hourly temperature less 76 ° F and zero;
- A second temperature variable, defined as the hourly temperature - 102° F, which addresses the so-called "topping off" effect – a reduction in the *rate* of load increases at very high temperatures;
- A misery buildup variable, which accounts for two additional weather phenomena beyond the current hourly temperature:
  - NOAA's misery index reflecting the combined effects of humidity and warm temperatures;
  - The build-up or duration of the misery index, which is captured through the weighted average of past hourly values of a heat index[1] ;
- Wind speed;
- 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.
- Binary variables representing:
  - Start of the school in August and summer vacation beginning in May
  - Days of the week (Monday through Saturday)
  - Months (June, July, August, and September), which are also interacted with the days of the week and hourly temperature

Relevant weather stations are shown below in Table II-3, along with the OG&E population estimates from the 2000 census used to weight the data from each station:

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[2]	153,029	8.0%

[1] The lag structure is designed to measure 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 a 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.

Weather Station	Population in OG&E Territory	Weight (% of OG&E population)
Muskogee	109,834	5.7%

Table II-3 Weather Station Weights

b. Forecasting Peak Loads

Once the equations have been finalized, the peak demand forecast is generated using a probabilistic approach by using all 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 1973 to 2004 through the peak demand model and also alternates the weather year "starting day" seven times so that extreme weekday (weekend) weather event probability is reflected directly in the simulations. With a matrix of 32 weather years by seven days, the 2005 forecast has a total of 224 simulations for each hour.

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

- Hourly load forecasts for each year in the forecast horizon (2005-2014) are obtained by multiplying model coefficients with the corresponding values of weather-related variables. As described above, this step generates 224 forecasts.
- For each forecast year, we first rank the 224 annual load forecasts are ranked and assigned a probability of occurrence by applying a uniform distribution (i.e., each weather has an equal chance of occurrence).
- For 30 year modeling, demands continue to grow at the same trend as the average growth over the forecast horizon (2005 -2014).

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

Table II-4 below illustrates the mapping between event occurrence probability and corresponding weather years. Thus, the expected load projections associated with a 1-out-of-2-years (the average weather year) event are obtained from a 1984 weather-year simulation. 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. Similarly, the 1991 actual weather corresponds to an event that happens in at least three out of four years. In this case, the peak load will be below this level 25% of the time and above this level 75% of the time.

---

2 While OG&E does not serve Stillwater, this weather station was the northernmost station with the required weather history.

Event Occurrence[3]	Occurrence Probability	Weather Year
1 out of 30 years	3%	1998
1 out of 10 years	10%	1978
1 out of 4 years	25%	1981
1 out of 2 years	50%	1984
3 out of 4 years	75%	1991
9 out of 10 years	90%	2004
29 out of 30 years	97%	1973

Table II-4 Probability of Occurrence

c. Expected Loads by Weather Probability

Table II-5 and Figure II-2 summarize the peak load model forecasts with a 95% percent confidence interval around potential weather events. It should be noted that these estimates exclude the peak demands attributable to the OMPA PSA that are added separately. The 1-out-of-2- years or "expected" forecast shows the peak demand level reflecting the average of all weather years. In this case, there is a 50% probability that the peak load will reach this load level or higher. The 1-out-of-10 forecast, which is approximately 140 MW higher than the 1-out-of-2-years case, shows the estimated peak demand under a more extreme weather event that is expected to occur only 10% of the time. Stated 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. The key area of uncertainty is in ***which*** year this event will occur.

Year	Peak Demand Forecast (MW)						
	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
2006[4]	6,122	6,076	6,040	5,938	5,725	5,649	5,601
2007	6,233	6,188	6,151	6,049	5,836	5,760	5,712
2008	6,334	6,289	6,253	6,151	5,938	5,862	5,814
2009	6,404	6,359	6,322	6,220	6,008	5,931	5,883
2010	6,516	6,471	6,434	6,332	6,120	6,044	5,995
2011	6,600	6,555	6,518	6,417	6,204	6,128	6,079
2012	6,701	6,656	6,619	6,517	6,304	6,228	6,180
2013	6,793	6,747	6,711	6,609	6,396	6,320	6,272
2014	6,924	6,878	6,842	6,740	6,527	6,451	6,403
2015	7,073	7,028	6,992	6,890	6,677	6,601	6,553

Table II-5 Peak Demand Model Forecasts by Weather Probability (Excludes FERC Sales)

It is possible to have significantly different weather conditions from one forecast year to another. Specifically, one can see how it might be possible one year to have a low peak load forecast corresponding to an almost average weather year, such as a 1-out-of-2-years weather event, and a much higher peak load forecast under more extreme weather conditions, as in a 1-out-of-40-years case, in the following year. In this case, dramatic

[3] This means that the weather is at least as hot as in X out of Y years.

[4] As of August 10, 2006, OG&E had recorded an actual demand of 6,472 MW.

weather condition changes, not economic growth, are responsible for the large difference in peak load forecasts for these two years. Conversely, it is possible for the peak load to decline from one year to the next even with underlying economic growth. Overall, the 95% confidence interval associated with weather conditions represents a significant source of risk responsible for over 500 MW of potential peak load variability. The 1-out-of-2-year (distribution average) case represents the "point estimate" from which further FERC adjustments and resource planning decisions are made. On average, peak loads are expected to grow at annual rate of about 2.0% *before* wholesale sales contracts.

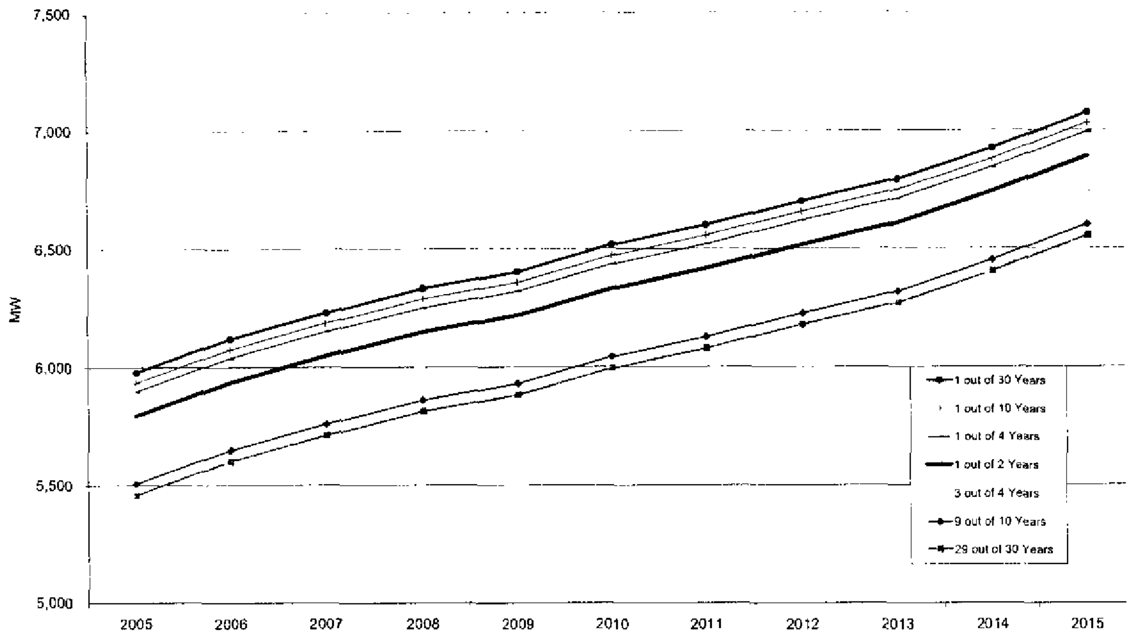


Figure II-2 Peak Demand Model Forecasts by Weather Probability (Excludes Wholesale Sales)

d. Total Peak Demand, Including Wholesale Contracts

Table II-6 presents the percent increases by customer class, including those associated with wholesale sales contracts assumed to continue over the planning period. These contracts include Arkansas Valley Electric Coop (AVEC); a 220 MW load that is being served on a 30-month evergreen contract. It is expected that peak demands will grow at pre-recession levels over the forecast period, consistent with the underlying economic forecast.

	Actual				Forecast					
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Residential	0.8%	1.2%	0.5%	1.7%	2.1%	1.9%	2.2%	1.2%	2.0%	1.2%
Commercial	0.1%	-0.1%	1.5%	2.7%	2.6%	2.3%	2.4%	1.7%	2.0%	1.7%
Industrial	0.3%	-0.1%	3.5%	3.6%	3.4%	3.1%	3.1%	2.6%	2.5%	2.4%
Industrial Petroleum	-0.1%	1.9%	4.4%	2.6%	3.7%	-0.7%	-4.2%	-4.1%	-0.1%	-1.4%
Total Industrial	0.1%	0.6%	3.8%	3.2%	3.5%	1.8%	0.6%	0.4%	1.7%	1.2%

	Actual				Forecast					
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Public Authority and Street Lighting	2.4%	0.0%	3.9%	3.3%	2.6%	2.8%	3.0%	2.6%	2.9%	2.6%
Total Retail Sales	0.6%	0.6%	2.1%	2.6%	2.7%	2.1%	1.9%	1.3%	2.0%	1.5%
Total FERC Sales	-10.2%	0.2%	-9.4%	3.0%	-0.5%	2.5%	2.4%	2.3%	2.3%	2.2%

Table II-6 Annual Percent Increase by Customer Class

The demand forecast is based on average weather conditions over the past 32 years. Underlying retail peak loads are anticipated to grow at an average annual rate of 1.8% over the next decade, which is slightly less than the growth rate for retail energy sales.

The Base Case forecast of needs is based on the projected peak demand (based on a 1-out-of-2-years weather event) in Table II-7 below.

Year	Weather Adjusted Native Load Requirement (MW)	Annual % Increase	Actual Native Load (MW)	Weather Adjustment (MW)	Absolute Percent Weather Adjustment
1998	5,279		5,180	99	1.9%
1999	5,385	2.0%	5,503	(118)	2.1%
2000	5,513	2.4%	5,494	19	0.3%
2001	5,651	2.5%	5,508	143	2.6%
2002	5,607	-0.8%	5,373	234	4.4%
2003	5,656	0.9%	5,608	48	0.9%
2004	5,759	1.8%	5,435	324	6.0%
2005	5,820	1.1%	5,751	69	1.2%
2006	5,952	2.3%			
2007	6,065	1.9%			
2008	6,169	1.7%			
2009	6,243	1.2%			
2010	6,358	1.8%			
2011	6,445	1.4%			

Table II-7 Actual and Projected Total Peak Demands

3. Low and High-Growth Cases

Two other demand growth scenarios were evaluated in order to assess the impact of either much higher growth (High Growth) or lower growth (Low Growth). The High Growth Case assumes stronger Oklahoma and Arkansas economies. In this case, peak demand grows at an average rate of 2.01 %/year over the forecast (compared to 1.76 %/year for the Base Case) and energy sales are projected to grow at a rate of 2.40 %/year compared to the 1.66 %/year for the Base Case. The High Growth Case assumes a robust economy. Conversely, the Low Growth Case assumes weak Oklahoma and Arkansas economies, producing a lower forecast of peak demand (0.88 %/year growth rate) and energy growth (0.83 %/year growth rate). The Low Growth Case was developed by assuming that energy sales and peak demand will grow at one-half the rate of growth in the Base Case.

The energy and peak demand forecasts for each of the three cases are also shown in Figure II-3 and Figure II-4 below.

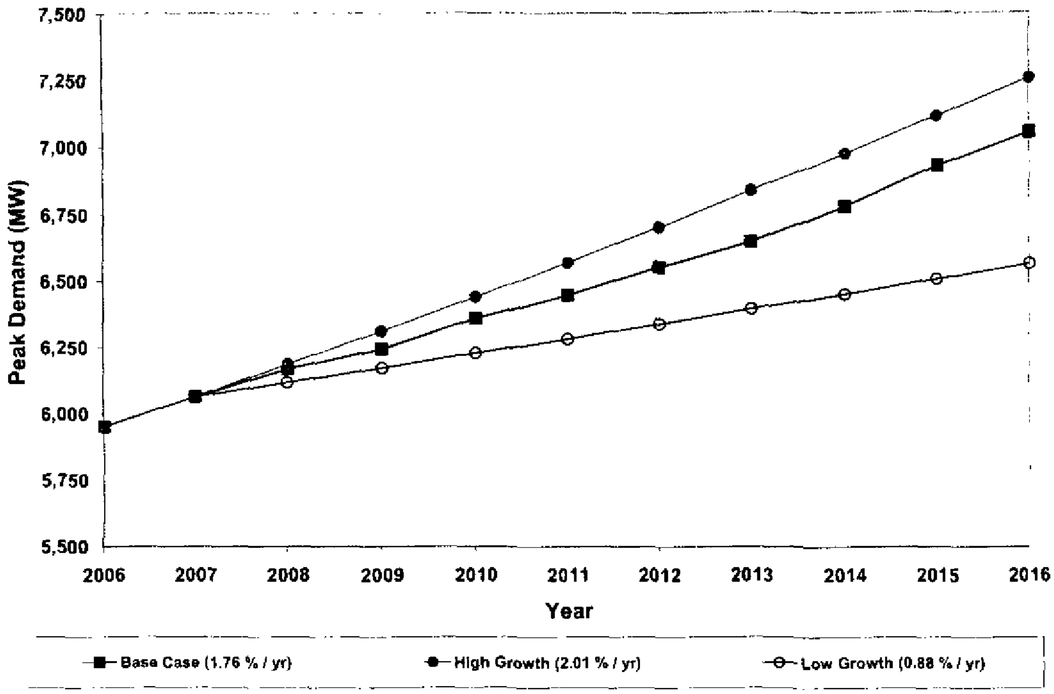


Figure II-3 Scenario Peak Demand Variation (Average Growth in %/yr)

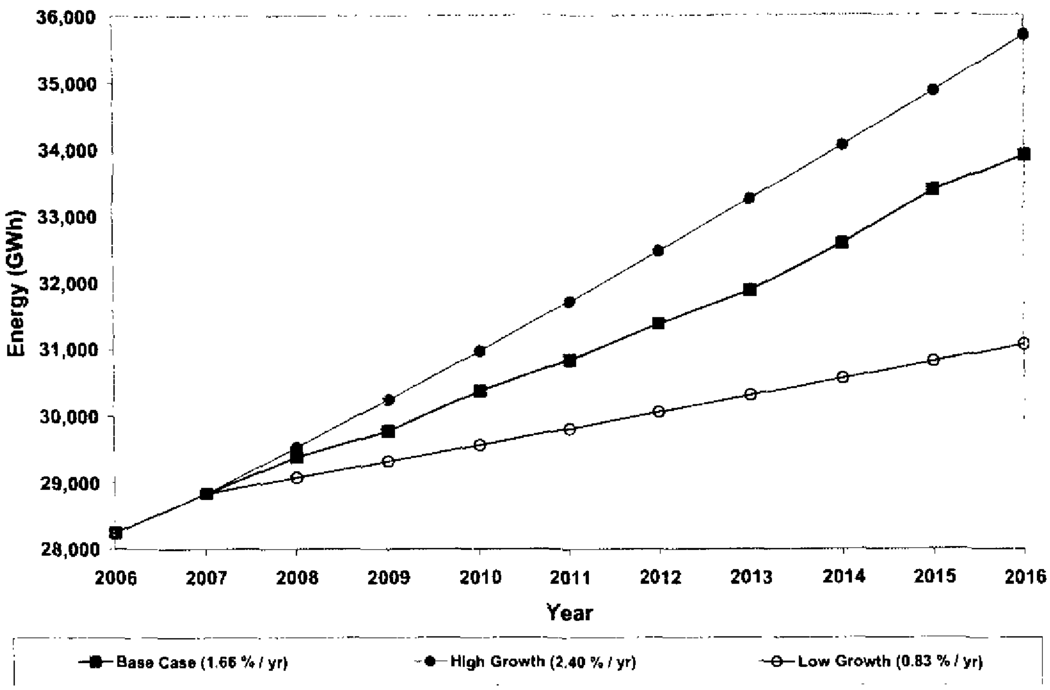


Figure II-4 Scenario Energy Forecast Variation (Average Growth in %/yr)

D. Calculation of Capacity Needs

1. Required Reserve Margins

The assessment of the magnitude of OG&E's capacity resource needs is based on the difference between existing OG&E supply and OG&E demand plus an estimate of the capacity reserve margin.

Section 4.3.5 of the SPP Criteria establish the basis and define 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."

Because the capacity margin and load margins are both margins derived from similar variables, it is sometimes easy, although incorrect, to confuse the load reserve margin as representing the same thing as a capacity reserve margin. Mathematically, a 12%

planning capacity margin is equal to a 13.636% planning load reserve margin. Again, as stated previously, the SPP Criteria requires a 12 % minimum capacity reserve margin.

2. Base Case - Capacity Margins

Outlined in Table II-8 below are the cumulative magnitudes of new resources needed each year for the period 2007 through 2016 for the Base Case demand scenario. 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.

As shown in Table II-8, OG&E's capacity needs increase by approximately 100 MW per year through 2013, a projection that is consistent with historical experience. However, as described in Section V, the size of potential capacity additions are determined by available technology and tend to be lumpy and therefore the capacity margin is a minimum target, not an economic optimal value.

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
A. Resources (MW)										
1 Existing Capacity	6,169	6,169	6,169	6,169	6,169	6,169	6,169	6,169	6,169	6,169
2 Committed Retirements	0	0	0	0	0	0	0	0	0	0
3 Total Owned Capacity	6,169	6,169	6,169	6,169	6,169	6,169	6,169	6,169	6,169	6,169
4 Purchase Contracts	581	581	581	581	581	581	581	581	581	581
5 *Additional Forecasted* Capacity (Cumulative)	**0**	**120**	**210**	**340**	**430**	**550**	**660**	**810**	**980**	**1,120**
6 Total Net Dependable Capacity	6,750	6,870	6,960	7,090	7,180	7,300	7,410	7,560	7,730	7,870
B. Demand (MW)										
7 Forecast	**6,065**	**6,169**	**6,243**	**6,358**	**6,445**	**6,549**	**6,643**	**6,776**	**6,926**	**7,051**
8 Demand Side Programs	127	127	127	127	127	127	127	127	127	127
9 Net On System Demand	5,938	6,042	6,116	6,231	6,318	6,422	6,516	6,649	6,799	6,924
C. Capacity Margin										
12 Capacity Margin (MW)	812	828	844	859	862	878	894	911	931	946
13 Percent Capacity Margin	12.0%	12.0%	12.1%	12.1%	12.0%	12.0%	12.1%	12.1%	12.0%	12.0%

Notes:

Line 1, 2, & 3: Existing Capacity assumes system coal efficiency enhancements (25 MW each in 2006 and 2007), repair of Enid (48 MW) in 2007, existing wind capacity (planning capacity of 3 MW), addition of Centennial Wind Farm (planning capacity of 6 MW) in 2007, Conoco retirement in pre-summer 2006 (60 MW), and all other capabilities (total of 6,122 MW) remain at the level as indicated on 2005 unit capability study dated Dec. 31, 2005.

Line 4: Purchase Agreements include Southwestern Power Administration (SPA) allocation (31 MW) and existing cogeneration contracts (Applied Energy Services, Inc. (AES) - 320 MW, Mid-Continent Power Company, Inc. (MCPC) - 110 MW, PowerSmith -120 MW). No determination has been made whether to exercise the option for MCPC or AES contract terminations.

Line 5: Additional Capacity Need starts in 2008. Additional forecasted capacity is determined by finding the amount of capacity, to the nearest 10 MW block, needed to meet current SPP minimum 12% Capacity Margin requirement.

Line 7: Demand is based upon OG&E 2005 Retail Load Forecast.

Line 8: *Megawatts associated with Demand Side Programs are assumed to be constant throughout the planning period. Demonstrated* performance is reflected, adjusted for losses.

Definition:

Capacity Margin: Capacity Margin shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Peak Responsibility.

Percent Capacity Margin: Percent Capacity Margin shall be defined by the formula: Percent Capacity Margin = (Capacity Margin/System Capacity) x 100

Table II-8 Capacity Planning Margins – Base Case Scenario

3. Low and High-Growth Cases

As shown in Table II-9, the alternative High and Low Growth forecasts have a significant impact on the need for additional capacity, again based on maintaining a 12% reserve margin.

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
A. Base Case (MW)										
Additional Forecasted Capacity (Cumulative)	0	120	210	340	430	550	660	810	980	1,120
Forecast	6,065	6,169	6,243	6,358	6,445	6,549	6,643	6,776	6,926	7,051
B. High Growth Case (MW)										
Additional Forecasted Capacity (Cumulative)	0	140	280	430	570	720	880	1,030	1,190	1,350
Forecast	6,065	6,187	6,311	6,438	6,568	6,700	6,834	6,972	7,112	7,255
C. Low Growth Case (MW)										
Additional Forecasted Capacity (Cumulative)	0	60	120	190	250	310	370	440	500	570
Forecast	6,065	6,118	6,172	6,226	6,281	6,336	6,392	6,448	6,505	6,562

Table II-9 Base, Low, and High Growth Peak Demand Forecasts

As shown in Table II-9, the Base Case shows a need for additional capacity of 430 MW in 2011 growing to 1,120 MW in 2016. The High Growth Case shows a need for additional capacity of 570 MW in 2011 growing to 1,350 in 2016. The Low Growth Case shows a need for additional capacity of only 250 MW in 2011 and 570 MW in 2016.

III.OG&E's Resource Portfolio and Regulatory / Legislative Drivers

This section describes OG&E's current resource portfolio, including a discussion of the transmission system. Many of the key inputs into the portfolio optimization models (Section IV) are presented in this section, including generation plant operating characteristics. It also includes a discussion of anticipated SPP market developments and regulatory and legislative "drivers" that will have an impact on OG&E's resource portfolio.

In Sections III.C and III.D that follow, data is obtained from several external sources, including the SPP. When data from published sources was used, every attempt was made to use the latest published sources that were available at the time this IRP report was prepared, which was prior to the submittal of this IRP by September 1, 2006.

A. Existing Generation and DSM Resources

OG&E's generation resources include coal-fired units, gas-fired steam units, gas-fired combined cycle (CC) units, and gas-fired combustion turbine (CT) units. Generation facilities owned by OG&E comprise approximately 91% of OG&E's 2006 summer peak generating capacity, with the remaining 9% supplied by long-term purchase agreements. Figure III-1 below shows the composition of OG&E's generation resources. OG&E's "net dependable rated capability" is reported on the OG&E 2005 Capability Report that is published on the last day of each year. The capabilities are determined from unit testing during the summer months in accordance with SPP Criteria 12. The latest Capability Report was published on December 31, 2005 and reported a "net dependable rated capability" of 6,122 MW from OG&E's nine power plants; this number is the basis for OG&E's capacity margin for 2006.

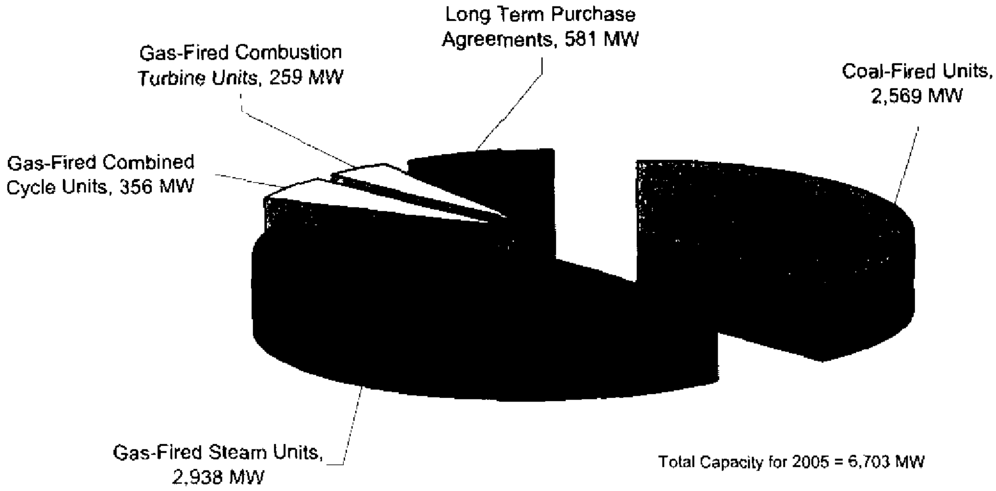


Figure III-1 2005 OG&E Generation and PPA Capacity (MW)

OG&E generates approximately 70 percent of its electric energy from low-sulfur Wyoming coal and 30 percent from all other sources. Although there are abundant supplies of natural gas in the region, OG&E began developing coal plants after a decision in the 1960s to diversify its portfolio and contract for high-quality, clean-burning, low-sulfur coal from Wyoming. By 1984, OG&E had five coal-fired generation units generating the bulk of its power output: three at Muskogee and two at the Sooner plant.

The 1980s also witnessed the emergence of Independent Power Producers (IPPs) and Qualifying Facilities (QFs), as Oklahoma and other states adopted rules to implement the Public Utility Regulatory Policies Act of 1978 (PURPA). OG&E would ultimately purchase 550 MW from 3 QFs. More than half of the QF generating capacity, or 320 MW, is from the AES plant at Shady Point that burns Oklahoma coal. The other two major QF contracts use natural gas as a fuel: 120 MW from PowerSmith Cogeneration Project Limited Partnership (SCI) in Oklahoma City and 110 MW from MCPC in Pryor.

More recently, between 2000 and 2003, OG&E negotiated a purchase power agreement from neighboring utility Southwestern Public Service. OG&E purchased 104 MW of capacity in 2000, 200 MW of capacity in 2001, 150 MW of capacity in 2002, and finally 200 MW of capacity in 2003. OG&E then began to look towards ownership options to meet the growing resource needs. Finally, exploiting a surplus of capacity in the SPP market area, OG&E purchased a 77% portion of the highly efficient, natural gas-fired combined cycle McClain Power Plant, completing the transaction in July 2004.

OG&E's current portfolio of electric generating facilities is presented in Table III-1. With the exception of the McClain plant, which is jointly owned with OMPA, OG&E fully owns all of its plants. OG&E is the operator of all of its plants including McClain. Many of the characteristics presented in Table III-1 are inputs into the resource optimization models presented in Section IV. Note that all units have remaining expected lives that extend beyond the 30-year period used in the resource optimization models.

Unit Name	First Year in Service	Expected Life (Years) (1)	Maximum Capacity (MW) (2)	Full Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-yr)
Coal-Fired Units:						
Muskogee 4	1977	>30	510.5	[redacted]	[redacted]	[redacted]
Muskogee 5	1978	>30	521.6	[redacted]	[redacted]	[redacted]
Muskogee 6	1984	>30	515.0	[redacted]	[redacted]	[redacted]
Sooner 1 (3)	1979	>30	535.0	[redacted]	[redacted]	[redacted]
Sooner 2 (3)	1980	>30	537.0	[redacted]	[redacted]	[redacted]
Subtotal Maximum Capacity			2,619.1			
Gas-Fired Steam Units:						
Horseshoe Lake 6	1958	>30	168.5	[redacted]	[redacted]	[redacted]
Horseshoe Lake 7	1963	>30	217.0	[redacted]	[redacted]	[redacted]
Horseshoe Lake 8	1968	>30	387.0	[redacted]	[redacted]	[redacted]
Muskogee 3	1956	>30	166.0	[redacted]	[redacted]	[redacted]
Mustang 1	1950	>30	53.0	[redacted]	[redacted]	[redacted]
Mustang 2	1951	>30	53.0	[redacted]	[redacted]	[redacted]
Mustang 3	1955	>30	117.5	[redacted]	[redacted]	[redacted]
Mustang 4	1959	>30	250.0	[redacted]	[redacted]	[redacted]
Seminole 1	1971	>30	506.0	[redacted]	[redacted]	[redacted]
Seminole 2	1973	>30	500.5	[redacted]	[redacted]	[redacted]
Seminole 3	1973	>30	519.0	[redacted]	[redacted]	[redacted]
Subtotal Maximum Capacity			2,937.5			
Gas-Fired Combined Cycle Units:						
McClain	2001	>30	355.5	[redacted]	[redacted]	[redacted]
Subtotal Maximum Capacity			355.5			
Gas-Fired Combustion Turbines:						
Conoco 1 (4)	1991	N/A	31.5	[redacted]	[redacted]	[redacted]
Conoco 2 (4)	1991	N/A	28.3	[redacted]	[redacted]	[redacted]
Enid	1965	N/A	0.0	[redacted]	[redacted]	[redacted]
Horseshoe Lake 7GT (5)	1963	>30	17.0	[redacted]	[redacted]	[redacted]
Horseshoe Lake 9	2000	>30	45.5	[redacted]	[redacted]	[redacted]
Horseshoe Lake 10	2000	>30	45.5	[redacted]	[redacted]	[redacted]
Seminole 1GT	1971	>30	16.0	[redacted]	[redacted]	[redacted]
Tinker 5A	1971	>30	31.0	[redacted]	[redacted]	[redacted]
Tinker 5B	1971	>30	33.0	[redacted]	[redacted]	[redacted]
Woodward	1963	>30	12.0	[redacted]	[redacted]	[redacted]
Subtotal Maximum Capacity			259.8			
Wind Turbine Units:						

Unit Name	First Year in Service	Expected Life (Years) (1)	Maximum Capacity (MW) (2)	Full Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-yr)
Sooner Wind Farm (6)	2004	>30	50.0 (3.0)	[redacted]	[redacted]	[redacted]
Centennial Wind Farm (6)	2007	>30	120.0 (6.0)	[redacted]	[redacted]	[redacted]
Subtotal Maximum Capacity			9.0			
Total Maximum Capacity			6,180.9			
Less: Sooner Coal Unit Efficiency Improvements			(50.0)			
Less: Wind Turbine Unit Planning Capacity			(9.0)			
Total Maximum Capacity as per OG&E Capability Report dated 12/31/2005			6,121.9			
Notes:						
(1) All units assumed to be active during study period of 2007 through 2036.						
(2) Based upon OG&E Capability Report dated December 31, 2005.						
(3) Maximum capacity of each unit includes 25 MW of efficiency improvements to take place in 2006.						
(4) Conoco units are to be removed from service in 2006.						
(5) Combustion turbine modeled with corresponding steam turbine.						
(6) Planning capacity (in parentheses) assumed to be 5% of maximum capacity.						

Table III-1 OG&E-Owned Generating Facilities (Detailed)

Figure III-2 below shows the load responsibility distribution curve for OG&E in 2005.

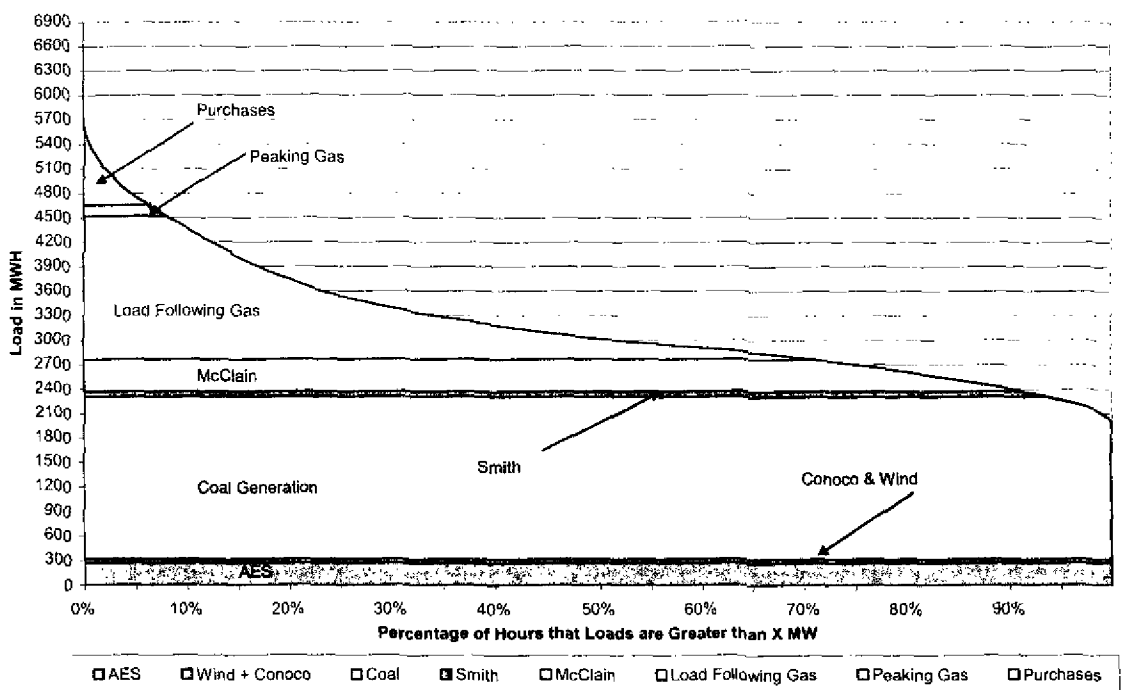


Figure III-2 OG&E 2005 Load Responsibility Distribution Curve

1. Retirement of Generation Facilities

OG&E recently retired two units located at the Conoco refinery. The co-generation contract with Conoco expired June 1, 2006 and OG&E has a contractual requirement to remove the units from the Conoco site. OG&E decided to retire the units due to the condition and age of the units. The units were purchased used in 1991 to fulfill the co-generation contract and have come to the end of their useful life.

OG&E considered both the mothball and retirement of all existing gas units as an option in its analytical modeling process. OG&E assumes that units would be available indefinitely if O&M and capital expenditures were made in a timely manner. It has been OG&E's experience that no single "big bang" event would result in such a high repair cost to economically justify the retirement of a unit. OG&E realizes the market changes over time and will continue to consider retirement or mothball of a unit on an individual basis before major capital improvements are made.

2. Enid Improvements

OG&E has not operated the 48 MW Enid plant due to operating issues that developed while it ran continuously for two months to serve the town of Enid due to transmission line outages after a major ice storm. OG&E is currently planning for repairs and upgrades to prepare it for the 2007 running season at an estimated investment of approximately $6 million. This is a very economical source of incremental capacity at approximately 125 $/kW. This capacity addition is reflected in the resource mix beginning in 2007.

3. Qualifying Facilities Purchase Power Contracts

Three separate purchase power contracts are in affect between OG&E and qualifying facilities (cogeneration plants). The Qualifying Facilities are listed below in Table III-2.

Qualifying Facilities	Capacity	Existing Term
AES Shady Point	320 MW	January 14, 2008
PowerSmith	120 MW	August 31, 2019
MCPC	110 MW	January 1, 2008

Table III-2 Qualifying Facilities

These contracts have been in affect since the 1980's and have been a reliable source of capacity for the OG&E load. As shown the existing terms of both the AES Shady Point and MCPC contracts expire within the planning horizon. These contracts will be continuously evaluated in OG&E's ongoing planning process. The PowerSmith purchase power contract was negotiated in 2004 for a term of 15 years.

4. Wind Generation

In 2003, OG&E began to consider wind as an energy resource for customers. OG&E utilized a competitive Wind Energy RFP to select the best provider of wind energy for

OG&E customers. As an outcome of this process, OG&E entered into a 15-year energy purchase contract with FPL Energy Sooner Wind, LLC (FPL). The contract is for the output of 34 wind turbines with a nameplate capacity of 1.5 MW each for a total of 51 MW. The turbines are located in Woodward, Oklahoma, and are directly interconnected to the OG&E transmission system.

Based upon OG&E's experience incorporating the wind energy purchased from FPL it determined that additional wind energy resources could be incorporated into its portfolio and benefit OG&E's customers as a hedge against high gas costs. OG&E has subsequently further studied the market for purchasing additional wind energy and determined that owning and operating the new wind farm is a more cost-effective solution for OG&E's customers. In 2006 OGE began construction of the new Centennial Wind Farm (Centennial), which will be built for OG&E in Harper County by Invenergy Wind Development Oklahoma LLC. Centennial will be one of only a few wind farms in the United States owned and operated by an electric utility. The facility is made up of 80 turbines capable of generating 1.5 MW each for a total of 120 MW.

5. Existing DSM

In the 1980's OG&E, like many other utilities, was heavily engaged in voluntary and mandatory DSM programs. In the 1988 Annual Report the company reported completion of the 69,000th home energy audit and installation of 123,000 PEAKS (direct air-conditioning controls). Subsequently, DSM declined in 1990s as State and Federal government officials viewed retail choice as a comprehensive solution to moderating electric price increases and it was anticipated that DSM would be provided by competitive retail service providers. Now, retail choice appears unlikely and with these customers continuing to receive cost-based regulated service, DSM again appears to be option.

OG&E's Load Curtailment program, which supplies 127 MW of avoided capacity to the current capacity supply mix, is our most successful DSM program. Recently OG&E expanded the program to include more customers and demand, and then through a series of actual curtailments refined the program to the current 80 customers who have demonstrated their ability and willingness to curtail when called on. The program is well established at this point and has been used successfully several times recently.

Furthermore, OG&E is currently studying the potential to obtain incremental DSM resources. This study will not be completed until 2007 and may require an update to the IRP if the results indicate that there are meaningful changes in DSM capacity.

B. Coal and Natural Gas Supplies

As is discussed in more detail in the Fuel Procurement / Risk Management Plan presented in Appendix A (Section 0), OG&E procures most of its natural gas and coal needs under long-term contracts. As these long-term contracts expire, OG&E will follow the procurement rules approved by the OCC in January 2006 to obtain new long-term supplies.

1. Coal Supply and Transportation

OG&E currently has contracts to purchase low-sulfur coal from four producers located in the Southern Powder River Basin (SPRB) of Wyoming. The majority of the contracts are fixed base price plus escalation for changes in government imposition. The terms for most of the contracts begin expiring in 2008 with all contracts terminating at the end of 2011. Coal suppliers are reluctant to provide bids that may be publicly disclosed and to hold their bid price firm for more than a very limited time. As these contracts expire, OG&E will review what approaches are in the best interest of customers and may seek waivers from the new OCC procurement rules if necessary to arrange the best contracts for customers.

There are very few options that exist for transportation. Constructing access to the plants for other carriers requires substantial time and capital. Current transportation from the SPRB is near capacity with both railroads announcing capital improvements in trackage and substantial purchases of locomotive power over the next several years. New mines have been announced and closed mines are being reopened, assuring adequate supply of coal.

OG&E currently has long-term transportation contracts with both BNSF Railway Company (BNSF) and Union Pacific Railroad Company (UP), which are set to expire on December 31, 2008. Coal for both the Muskogee and Sooner stations is shipped from SPRB mines via UP. UP delivers the coal into the Muskogee Plant. Coal for the Sooner Plant is delivered by UP to the interchange at Topeka and picked up by BNSF for delivery. Once these existing contracts expire, OG&E is likely to seek a waiver from the new OCC procurement rules since there is only one viable choice for service to each of the coal plant locations.

2. Natural Gas Supply and Transportation

OG&E competitively bids for all of its natural gas requirements. The three major types of natural gas supply contracts are:

- Base load gas (long-term contracts with terms longer than 30 days)
- Monthly gas
- Daily gas

Historically when OG&E has competitively bid for gas supplies the number of bids received varies, but typical number of responses are 10 to 12 for long-term base load supplies and five to seven for 30-day supplies. There are multiple long-term contracts expiring in 2007. They are from various gas suppliers connected to the Enogex pipeline transmission system. All bids are tied to various Oklahoma Mid-Continent posted Inside FERC first of the month indices. OG&E retains the option to convert the index price to a fixed price at buyer's option. Day trade bids come from up to approximately 10 different suppliers on any given day and typically are tied to various Oklahoma Mid-Continent posted Gas Daily Daily prices.

To accommodate the three types of gas supply contracts and to provide OG&E with the required flexibility to operate its gas-fired generation plants, OG&E has secured integrated, firm no-notice load following service for both gas transportation and gas storage. OG&E currently purchases these services for all of its gas-fired generation plants except McClain from Enogex, a subsidiary of OGE Energy Corp. These services also allow OG&E to maximize the generation from its low cost coal-fired generation plants. Enogex is the pipeline affiliate that transports the gas to the OG&E power plants. In regard to gas transportation capacity, OG&E has a contracted Maximum Daily Quantity (MDQ) with Enogex of [redacted] during the months of January, February, May through September and December, and [redacted] for the months of March, April, October, and November.

If the SPP Market proposal is substantially approved by FERC, OG&E has concluded that the integrated, no-notice, load following service currently utilized by OG&E will be an advantage in the SPP Market. OG&E is currently exploring options to expand the number of transportation pipelines and/or storage facilities that could contribute to maintaining the current service, including use of a header system approach.

C. Transmission Capabilities and Expansion Plans

OG&E operates approximately 4,300 miles of transmission lines, 69 kV through 500 kV, throughout its two-state service territory of Oklahoma and Western Arkansas, and maintains a major control center in Oklahoma City, Oklahoma. Attached in this report binder is a map of OG&E's transmission system. These electric transmission lines form a network of interconnected conduits that move large amounts of power at high voltages from either power production plants (either OG&E-owned or other regional production plants) or from other interconnected interface points that link the OG&E system to other regional electric systems. This interconnected electric transmission system is used to transport the produced power to geographically dispersed OG&E substations or to other load serving entities. Power from these substations is then distributed on lower voltage lines to homes and businesses.

The OG&E transmission system is directly interconnected with other utilities in the SPP, including American Electric Power ("AEPW" control area), Grand River Dam Authority ("GRDA" control area), Southwestern Power Administration ("SPA" control area), Western Resources ("WR" control area), and Western Farmers Electric Coop ("WFEC" control area). OG&E is also directly interconnected to both Entergy ("EES" control area) and Associated Electric Cooperative Inc. ("AECI" control area) in the Southeastern Electric Reliability Council (SERC).

OG&E's transmission system is operated on a non-discriminatory basis under the open access requirements established by the FERC. This means that all wholesale buyers and sellers can use the transmission system under the same terms and conditions used to serve OG&E's own retail customers.

1. Current Transmission System Adequacy

The OG&E Transmission System is reviewed for adequacy on a yearly basis by the Transmission Planning Department at OG&E. The guidelines used in the planning of the Transmission System are those established by the SPP and the NERC. OG&E performs numerous Contingency Studies in accordance with SPP Criteria Section 3.4 and NERC Planning Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The Loadflow Models used in the yearly Contingency Study are provided by the SPP and are based on near-term (current or next year), intermediate (two to five year) and longer-term (years six through ten) planning horizons. Attached in Appendix K are the results of the 2007-2016 Summer Peak Contingency Study with mitigation plans.

2. SPP Regional Transmission Organization (RTO) Expansion Plans

In addition, the SPP staff is responsible for development of SPP RTO Expansion Plans.[5] This involves a two-year planning cycle with the first year's focus on reliability and the second year's focus on economic upgrades. The SPP RTO expansion planning process is an open and collaborative effort using regional planning summits to present the process, discuss results, and collect feedback. The regional planning summits were well attended by a variety of attendees including regulators, SPP transmission owners, transmission owners from other regions, members of the Wind Coalition, load serving entities, consulting firms, and independent system operators. OG&E is an active participant in the development of these plans.

a. Reliability Upgrades

Phase I of the SPP RTO Expansion Plan 2005-2010 report addressed reliability violations and recommended projects to meet current planning standards. The projects identified in Phase I span October 2003 through December 2010, and the SPP system requires an investment totaling $552 million from all of its members. The estimated line mileage for new transmission lines for this period totaled 634 miles, while rebuilds/upgrades totaled 646 miles.

The major 345 kV projects over the study period are as follows:

- 105 mile Finney-Lamar 345 kV line and high voltage direct current (HVDC) tie – December 2004
- OGE Draper 345/138 kV transformer – June 2005
- American Electric Power (AEP) 14 mile Chamber Springs-Tontitown 345 kV line – June 2007
- AEP 22 mile Flint Creek-East Centerton 345 kV line – June 2010

OG&E constructed projects over the period necessary to remain compliant with NERC Reliability Standards, SPP Criteria, and OG&E planning criteria.

[5] The current SPP RTO Expansion Plan can be found at the following Internet site: http://www.spp.org/Publications/Final_Exp_Plan_TWG_Approved_092605.pdf.

b. Economic Upgrades

Some transmission projects may be justified based on their ability to improve the system in an economic manner, in addition to enhancing the reliability of the regional transmission system. Phase II of the SPP RTO Expansion Plan 2005-2010 addressed potential transmission projects that may be justified based on the expected economic benefits.

A market assessment was conducted during Phase II to determine potential projects for system reinforcement. Potential projects were identified from a variety of resources including stakeholder feedback, review of past transmission line loading relief, refused long-term transmission reservations and suggestions from summit participants during the Planning Summit III. Thirty-three projects were screened to determine the top four projects based on benefit-cost ratios. Due to the time constraint of performing market analysis for economic upgrades, only four projects were evaluated in detail by the SPP. These four projects were further studied by doing complete seasonal economic runs for 2005 and 2010.

The four projects selected by SPP for detailed analysis were:

1) 345 kV Tulsa East switching station to tie PSO's Northeastern-Oneta and GRDA's GRDA1-Tulsa N lines
2) Rose Hill-Sooner 345 kV
3) Sooner-Cleveland 345 kV
4) Tolk-Potter 345 kV

Projects Two and Three involve the OG&E transmission system. The Sooner-Cleveland 345 kV line is a 32-mile transmission line connecting OG&E's Sooner generating station to GRDA's Cleveland substation. The Rose Hill-Sooner 345 kV line is an 83-mile transmission line connecting Westar Energy's Rose Hill substation and OG&E's Sooner generating station.

For the evaluation of economic projects, the SPP used an 8 % discount rate and evaluated the benefits over a 10-year period using a two-step process. The first step determines if the dispatch cost plus violation cost savings over the studied period paid for the project. If the project is determined to be of benefit to the study area then the cost of the project was allocated to the beneficiaries.

Table III-3 shows the benefit-cost ratio for the four projects based on the calculated 10-year savings. The Sooner-Cleveland 345 kV line has the highest benefit-cost ratio, followed by the Tolk-Potter 345 kV line. The ratios for the other two projects were slightly less than 100% for a 10-year period.

Project	Cost (Million $)	10-Year Savings	Benefit-Cost Ratio
Tulsa East	$8.0	$7,819,177	98%
Sooner-Cleveland	$18.0	$25,446,587	141%
Rose Hill-Sooner	$43.5	$41,840,778	96%
Tolk-Potter	$29.5	$34,679,236	118%

Table III-3 Benefit-Cost Ratio Based on 10-Year Savings

Considering dispatch savings only and ignoring violation cost savings the Sooner-Cleveland project has a benefit-cost ratio of 80.9% and the Rose Hill-Sooner project's benefit-cost ratio is only 45.2%. The OG&E projects have declining benefits over a 10-year horizon and are marginal at best. Funding for economic projects is voluntary and cost recovery for projects with benefit-cost ratios less than one can be problematic.

A sensitivity analysis was conducted to determine how the benefit-cost ratio variance was effected by the sequence of the four project installations. The sensitivity runs revealed the order yielding the greatest benefit is Sooner-Cleveland 345 kV line, Tolk-Potter 345 kV line, Tulsa East Switching Station, and Rose Hill-Sooner 345 kV line.

OG&E will continue to monitor the economic upgrades from the SPP RTO Expansion Plan and the SPP cost allocation processes, and make a determination at a later date whether or not to construct any of the identified economic projects, as they become approved by the SPP.

3. FERC Transmission Considerations for Incremental Generation

OG&E's recent experience highlights the need to address potential FERC concerns before committing to new supply resources. On July 9, 2004, OG&E completed the acquisition of NRG McClain LLC's 77 percent interest in the 520 MW McClain Plant. The McClain Plant, which includes natural gas-fired combined cycle combustion turbine units, is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority.

The closing of the purchase of the McClain Plant was subject to approval from the FERC. On July 2, 2004, the FERC authorized the Company to acquire the McClain Plant. The FERC's approval was based on an offer of settlement in which OG&E proposed, among other things, to install certain new transmission facilities and to hire an independent market monitor to oversee OG&E's activity for a limited period. In the July 2, 2004 order, the FERC: (1) approved OG&E's offer of settlement subject to conditions; (2) rejected the competing offers of settlement; and (3) approved OG&E's acquisition of the McClain Plant. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (1) install certain transmission facilities designed to result in up to 600 MW of available transfer capability (ATC) from the Redbud Energy LP (Redbud) facility to OG&E's control area; (2) pending completion of these transmission upgrades, provide up to 600 MW of ATC into OG&E's control area from the Redbud plant through changes to the dispatch of OG&E's generating units; and (3) hire an independent market monitor to oversee OG&E's activity in its control area until the SPP implements a market monitor for the SPP RTO. OG&E completed the installation of the capital improvements that required an investment of approximately $18 million and notified the FERC in writing on May 31, 2005 that these were completed. OG&E's obligation to redispatch its system to make 600 MW of ATC available to the Redbud power plant terminated upon completion of the transmission upgrades. On June 20, 2006 the FERC issued an order declaring that OG&E had fully satisfied all of the mitigation requirements associated with its 2004 acquisition of the McClain power plant.

D. SPP and Regional Electricity Markets

OG&E is responsible for contracting for capacity and energy to meet its load requirements, including maintaining an adequate reserve margin. However, it does so in the context of a much broader regional market. Thus, fundamental supply and demand conditions and the continuing development of regional markets have a significant impact on OG&E's contracting for both capacity and energy on both a short-term and long-term basis. The recent acquisition of the McClain plant at a price that reflected surplus capacity in the region certainly demonstrates this point.

This section includes a discussion of SPP market fundamentals and the potential impact of new SPP market mechanisms.

1. SPP Overview

The SPP is the FERC-approved RTO and the NERC regional reliability organization for Oklahoma and the surrounding region. The SPP footprint covers 255,000 square miles in part or all of eight states and 4 million customers. It covers all of Kansas and Oklahoma and parts of six other states (Missouri, Arkansas, Texas, Louisiana, Mississippi and New Mexico). The SPP represents a group of 46 electric utilities, including OG&E, containing a population of over 18 million people; this geographic area is shown in Figure III-3. This membership is comprised of 13 investor-owned utilities, 7 municipal systems, 9 generation and transmission cooperatives, 2 state authorities, 3 independent power producers, and 12 power marketers.

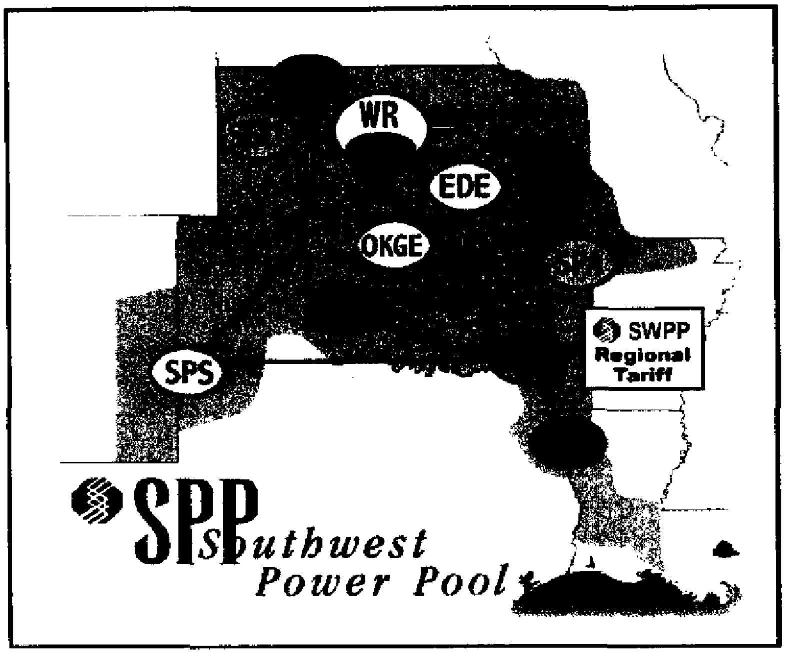


Figure III-3 SPP Geographical Area

The SPP has provided independent security coordination and tariff administration since 1997, pursuant to a FERC-approved tariff. Seventeen of the 150 control areas within the North American continent are members of the SPP. Table III-4 summarizes basic facts about the SPP.

Variable	Value
SPP Capacity (MW)	55,023
SPP Demand (MW)	40,187
Circuit Miles	52,301
Circuit Kilometers	84,780
Number of Participating Transmission Owners	11
Number of Transmission Customers	122
Number of Daily Transmission Schedules	650
Number of Network Nodes	5,793
Number of Total Members (as of 06/15/2006)	46

Table III-4 SPP Basic Facts

The SPP has direct interconnects to three emerging markets: Midwest ISO (MISO), Entergy, and Electric Reliability Council of Texas (ERCOT). The MISO and ERCOT have established markets that continue to be refined. The Entergy market is not a formal market but does offer opportunity for purchases and sales.

2. SPP Market Demand, Supply, and Prices

The SPP reached two new record peaks in 2006[6]: 41,324 MW on July 17 and 41,874 MW on July 18. This new peak of 41,874 MW was 4.2 % higher than the 2005 peak of 40,187 MW, which was 3.7 % higher than the 2004 peak of 38,767 MW. Not only was the annual peak higher in 2005, but the average monthly peak in 2005 was 7.4% higher than in 2004 indicating a broad increase across the year. Electric energy usage also increased by 4.2% over 2004. See Table III-5 for Monthly Peak Electric Energy Demand (MW) for SPP.

Month	Peak Demand (MW)				
	2001	2002	2003	2004	2005
January	25,213	26,732	27,813	27,727	27,513
February	24,055	26,225	26,550	26,794	25,659
March	21,802	26,226	24,355	22,489	24,916
April	23,142	26,187	25,728	23,010	25,087
May	29,432	31,118	30,699	32,042	33,093
June	31,675	34,179	35,210	34,350	38,906
July	36,898	37,817	37,044	37,695	40,187
August	36,518	38,200	38,196	38,767	39,654
September	30,118	35,646	30,868	34,076	37,157
October	21,786	30,726	24,523	24,955	32,643
November	24,613	24,088	23,867	26,040	26,524
December	22,769	26,122	24,844	28,621	30,686
Peak	36,898	38,200	38,196	38,767	40,187
Yearly Change	N/A	3.5%	0.0%	1.5%	3.7%
Source: FERC Form 714 and SPP OPS1 Note: The City of Lafayette, Louisiana (LAFA) control area is not included in 2004 data.					

Table III-5 Monthly Peak Electric Energy Demand (MW) for SPP

This demand is still substantially less than the 55,023 MW of generating capacity shown in Table III-6, and thus there is 14,836 MW of generating capacity in excess of peak load within the SPP footprint. The SPP has a significant resource margin (generation capacity in excess of peak demand) of 36.9%, reduced from 44.4% in 2004.

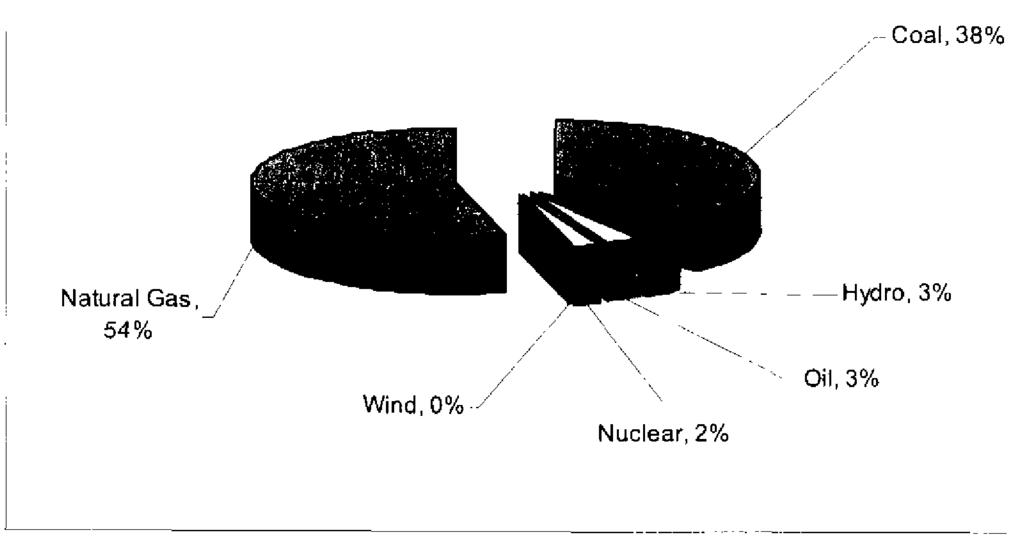
Control Area	Capacity (MW)
AEPW	14,409
OKGE	9,462
WERE	6,649
SPS	5,267
KCPL	4,360
CLEC	4,205
SWPA	2,555
Aquila-MPS	1,630
WFEC	1,238
EMDE	1,236
GRDA	1,141
KACY	723
SUNC	582

[6] This represents data available from the SPP as of July 20, 2006.

Control Area	Capacity (MW)
LAFA	480
Aquila-WEPL	399
INDN	288
OMPA	205
LEPA	194
Total	**55,023**
Source: SPP MKTSYM Note: OMPA is not a control area but was broken out separately for the purposes of this table. Note that 192 MW of OMPA's capacity are in OKGE's control area.	

Table III-6 Current On-Line Generation Capacity by Control Area

Since 2000, there has been a significant amount of construction of new natural gas-fired generating plants in the SPP region (approximately 13,790 MW), which have contributed to the 36.9% resource margin. There has also been an emergence of wind-powered generation in recent years. Figure III-4 presents the current SPP on-line generation capacity by fuel type.



Source: SPP MKTSYM

Figure III-4 Current On-Line SPP Generation Capacity by Fuel Type

Despite the current surplus of capacity within the SPP market, developers are continuing efforts to add new capacity to the market. This is evidenced by the fact that there are over 10,000 MW of new capacity seeking generation interconnection. It is not anticipated that all of these will make it to the point of signing an interconnection agreement. To put this in context, 160 projects have entered SPP's Generation Interconnection Queue since 2000, representing 47,855 MW of capacity. Of these, only 60 projects are currently active or have executed an interconnection agreement representing 10,959 MW of capacity; the remaining projects were withdrawn at some stage of the request process. Of these active projects, projects representing 3,524 MW of capacity have fully executed an interconnection agreement as shown in Table III-7 below.

Status	Number of Projects	Total Capacity (MW)
Interconnection Agreement Fully Executed	1	47.0
Interconnection Agreement Fully Executed/Commercial Operation	10	932.2
Interconnection Agreement Fully Executed/On Schedule	5	938.0
Interconnection Agreement Fully Executed/On Suspension	7	1607.0
Interconnection Agreement Pending	11	2,399.0
Facility Study in Progress	4	448.0
Impact Study Completed	3	550.5
Impact Study Revision in Progress	1	160.0
Impact Study in Progress	2	355.5
Impact Study Set to Begin	1	150.0
Feasibility Study in Progress	6	1,104.0
Feasibility Study Requested	9	2,267.5
Total	60	10,958.7
SOURCE: SPP OASIS, Generation Interconnection Queue at https://studies.spp.org/SPPGeneration/GI_ActiveRequest.cfm, February 21, 2006.		

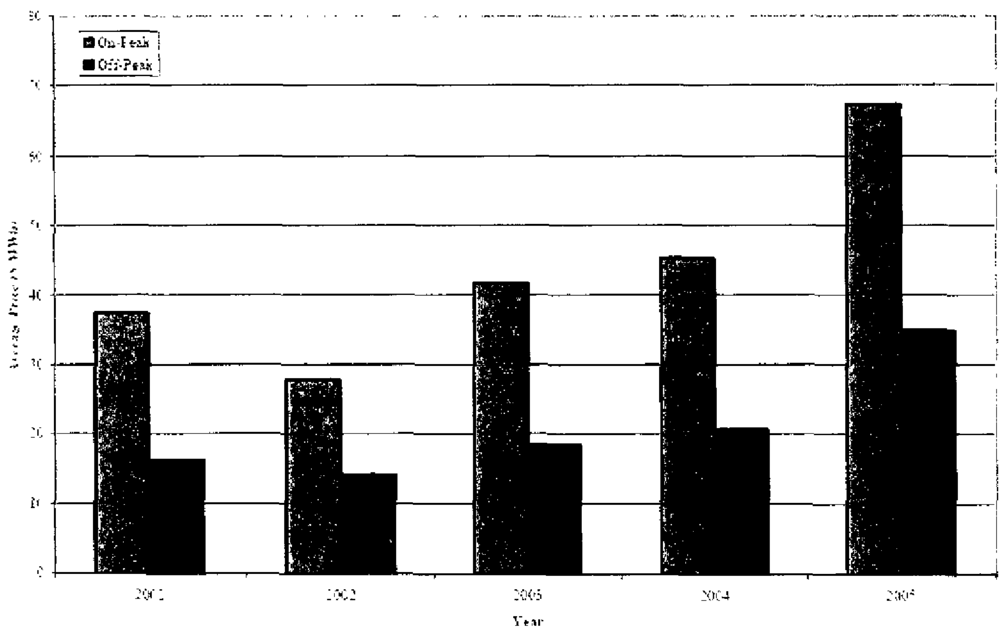
Table III-7 Status And Capacity of Active Generation Interconnection Requests

The SPP has a procedure for applicants requesting generation interconnection. In order to execute a Generation Interconnection Agreement three studies must be completed. The three studies are (1) Feasibility Study, (2) System Impact Study and (3) Facility Study. A Feasibility Study assesses the practicality and costs involved to incorporate the proposed generating unit(s) into the SPP Transmission System. The results of this study may be a list of proposed system upgrades needed along with initial cost estimates. A System Impact Study is a refinement of the Feasibility Study including (1) load flow analysis, (2) short circuit/breaker rating analysis, and (3) transient stability analysis. Finally, a Facility Study consists of the SPP or the Transmission Owner specifying and estimating the cost of equipment, engineering, and construction to implement the interconnection. Upon completion of the Facility Study, an applicant may proceed to execute a Generation Interconnection Agreement.

Upward pressure on natural gas prices has been a prime contributor towards more recent interest in new coal and wind capacity. Among the active generation interconnection requests, 51% of the capacity is for wind projects, while coal accounts for 28% and natural gas for 21%. The vast majority of gas-fired generation requests for interconnection were made prior to 2002, and little gas generation has been proposed since. However, coal and wind requests have remained fairly steady or increased in the more recent years.

SPP electricity prices reflect the surplus capacity conditions to some degree. Electricity prices are a result of the supply and demand for electricity and the ability of the transmission system to move electricity from the generators to meet demand. Electricity prices are also highly dependent on the price of generator fuel. Natural gas prices are especially influential on market-based electricity prices in the SPP as natural gas tends to be the incremental resource for the vast majority of the hours of the year. Thus, despite the surplus capacity in the market, energy prices have increased significantly over the past several years as shown in Figure III-5 below. Average on-peak prices in the SPP increased by 80% from 2001 to 2005 (from 37.45 $/MWh in 2001 to 67.40 $/MWh in 2005). The 2005 average on-peak price alone was 49% higher than that in 2004. Average off-peak energy prices in the SPP increased by 117% from 2001 to 2005 (from 16.09 $/MWh in 2001 to 34.91 $/MWh in 2005).

AVERAGE ELECTRICITY PRICES IN SPP FROM 2001 TO 2005



SOURCE: *Megawatt Daily*

Figure III-5 Average Electricity Prices in the SPP from 2001 to 2005

Rising natural gas prices are a driving force in the increase of on-peak electricity prices in the current bilateral electricity market in the SPP footprint. This is to be expected given the region's heavy dependence on natural gas for power generation. Average daily natural gas prices in the SPP region increased by 99% from 2001 to 2005 (from 3.86 $/MMBtu in 2001 to 7.67 $/MMBtu in 2005). Natural gas prices reached historic highs with a maximum price of 13.58 $/MMBtu in 2005. However, electricity prices have not increased sufficiently to cover the full increase in natural gas prices.

3. New SPP Market Services

The SPP received an order in October 2004 granting the organization RTO status from the FERC. In addition to serving critical planning and operating roles, the SPP plans to offer at least the Energy Imbalance Service (EIS) Market, and is considering an Ancillary

Services Market and a Day Ahead Energy Market. The uncertainty of a developing market(s) adds complexity to the OG&E resource planning process.

The SPP EIS Market is scheduled to become operational in November 1, 2006. The SPP EIS market is designed to allow generators and load serving entities to benefit from a RTO managed hourly non-firm energy market. These market transactions are intended to be more efficient and transparent than the current hourly bi-lateral market. Efficiencies are expected via maximization of the transmission system, centralized unit offers, and lack of transmission reservation requirements for market offers.

The SPP EIS market protocols require each Load Serving Entity to provide continuous on-line generating resources equal to or great than its load responsibility including reserve requirements. This requirement can be met by owned or contracted generating units. Therefore, OG&E will continue to commit its firm capacity generating units, either owned or under contract, to meet its load obligation and SPP reserve requirements. This practice remains the same before the market as after. Also, this market does not provide regulation or reserve services; therefore, OG&E must also ensure sufficient generation is on-line capable of meeting the minute to minute regulating requirements of the OKGE Balancing Authority. Other than administrative issues, these services will be managed the same before the market as after.

OG&E will schedule all, or nearly all, of the committed units to its forecasted load as if the SPP EIS market did not exist. Unit offer curves will be submitted which represent the incremental variable cost to operate each unit and the unit will be offered for market dispatch. This is known as scheduling and offering the unit. The SPP Security Constrained Economic Dispatch (SCED) system will evaluate all offers in the SPP market and will send dispatch instructions to the units which most economically fulfill the most current load forecast. Effectively the committed units will act as a physical hedge to fill the schedules while allowing less expensive generation to fill the schedule if it is available. If a unit is market dispatched above its schedule, then this indicates the market price is above the offer and the unit is providing power into the market. Constraints on coal units due to annual environmental caps or other issues will be handled by shifting the designated maximum output of the unit to preserve the low cost generation for native load customers.

The objectives of the SPP EIS are to:

- Increase market efficiencies through centralized market operations over a broad region
- Provide participants with access to more efficient and economical generation
- Provide non-discriminatory access to markets by third-party power producers (e.g. IPPs, etc.)
- Optimize regional operating practices to reduce wholesale buyers' costs
- Improve price transparency

An important financial characteristic of the SPP EIS Market is Locational Imbalance Price (LIP). LIP is important because this is the price load pays for EIS and generators get paid for EIS. It is important to note that a LIP is very seldom equal to a generation offer. A LIP is calculated for each generator and each load. LIPs have two components, energy price and transmission congestion price. Absence transmission congestion, all LIPs will equal the highest price generator offer required to fill the market load in that interval. This is known as the generator clearing price. When transmission congestion occurs another value is added to the generator clearing price for each location (load and generation). This congestion adder can be positive or negative. Due to the lack of history, broad assumptions were made for the EIS market impact assessment on OG&E's operations. To define the market two cases were analyzed:

- Minimal EIS Benefits - Assumes a market heat rate of 9,000 Btu/kWh. This heat rate was utilized because it is higher than the McClain facility, which is not expected to be impacted by average EIS market participation, but lower than the heat rates of OG&E's gas-fired boiler portfolio. A 9,000 Btu/kWh heat rate is slightly lower the conventional gas-fired steam units.
- Full EIS Benefits – Assumes a market heat rate of 8,000 Btu/kWh. This heat rate was utilized as IPPs are typically combined-cycle with heat rates of 7,500 Btu/kWh or lower. Since transmission constraints may limit their ability to serve OG&E load, an 8,000 Btu/kWh heat rate may give a better indication of the possible impact to OG&E gas-fired portfolio assuming full benefits.

The importance of heat rate in this analysis stems from the introduction of more efficient generators (generators with lower heat rate) that may be available to serve OG&E's load within the new SPP EIS market and would reduce the output from the OG&E gas-fired generators.

The amount of energy that can be purchased is limited by transmission and the security constrained economic dispatch of the SPP. Given the initial estimates under the Minimal EIS Benefits case (assuming a heat rate of 9,000 Btu/kWh), energy purchases would not exceed 8% of the gas energy generation. Under the Full EIS Benefits case (assuming a heat rate of 8,000 Btu/kWh); energy purchases would not exceed 18% of gas energy generation.

Future market development in the SPP remains uncertain at this time. The current draft SPP strategic plan states "SPP will evaluate a comprehensive market services design for the region including the requisite cost/benefit studies. A strategic decision will then be made concerning further market services development in the region."

4. Transmission Service and System Expansion

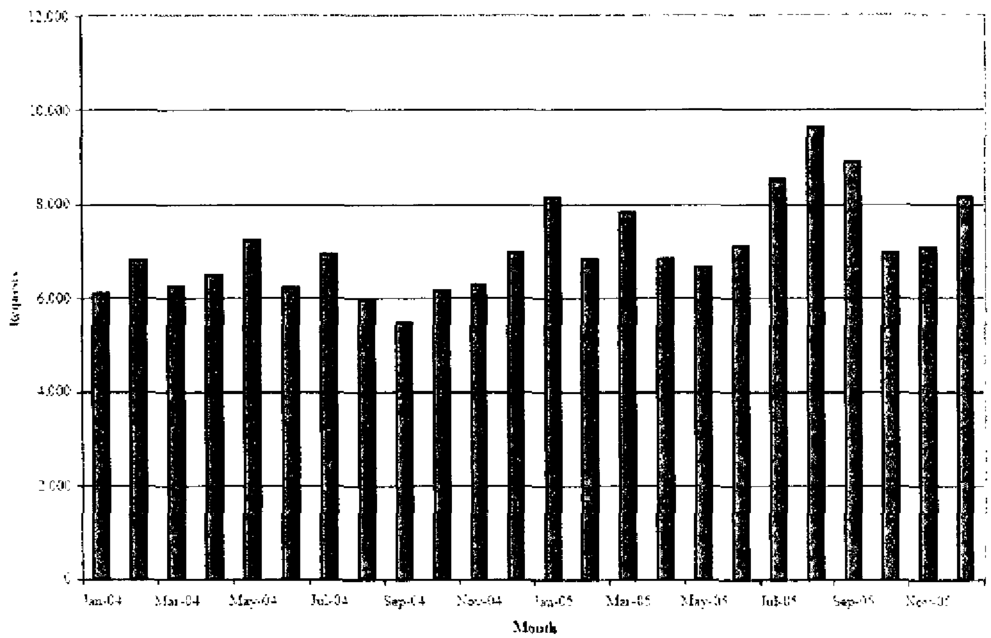
The SPP offers both Network Integration Transmission Service (NITS), and point-to-point transmission service under the SPP OATT posted on the Open Access Same-Time Information System (OASIS). Point-to-point transmission service is offered by SPP as a transmission provider to valid Points of Receipt (POR) and Points of Delivery (POD) under Part II of the OATT. Scheduling point-to-point transmission service is provided on a control area to control area basis. The SPP offers both firm and non-firm classes of point-to-point transmission service as defined in the OATT. Network Integration

Network Service (NITS) is offered by the SPP under Part III of the SPP OATT. NITS is offered on a firm basis for delivery of capacity and energy from designated Network Resources to Network load or on a non-firm basis to deliver energy to Network Load from resources not designated as Network Resources.

Under its OATT, the SPP grants transmission service over the transmission systems owned by its members. In return, SPP's transmission-owning members receive revenues for the service granted by the SPP. The cost recovery is based upon Base Plan Charges which shall be determined in accordance with Schedule 11 and assessed to Network Customers taking Network Integration Transmission Service to serve their Network Load under the SPP Tariff. The Network Customer and the Transmission Owner shall pay the Transmission Provider Base Plan Charges to recover the revenue requirement of facilities classified as Base Plan Upgrades. Through a request process, parties who wish to move electricity over these transmission systems request this service in advance. The SPP will approve these requests if it can do so while ensuring reliability and simultaneous feasibility, that is, while assuring that the capability of the transmission systems of its members to move electricity is not exceeded. The number and volume of requests for transmission service is an indicator of the level of demand for transmission service within the SPP footprint.

The trend in requests approved by the SPP and confirmed by parties making requests during 2004 and 2005 is shown in Figure III-6 and Figure III-7. These figures show the trend in both frequency and volume of MWh. In both series one can see the number of confirmed requests in 2005 is significantly higher than the corresponding confirmations in 2004. There were 76,992 requests confirmed in 2004 and 92,751 in 2005, an increase of 20%. For the same time periods the volume of confirmed requests increased from 214 GWh to 307 GWh, an increase of 44%. Expressed in terms of monthly averages, in 2004 there were 6,416 requests confirmed per month and 7,229 in 2005. During the same time periods, the average monthly volume of confirmed requests increased from 17.8 GWh to 25.6 GWh.

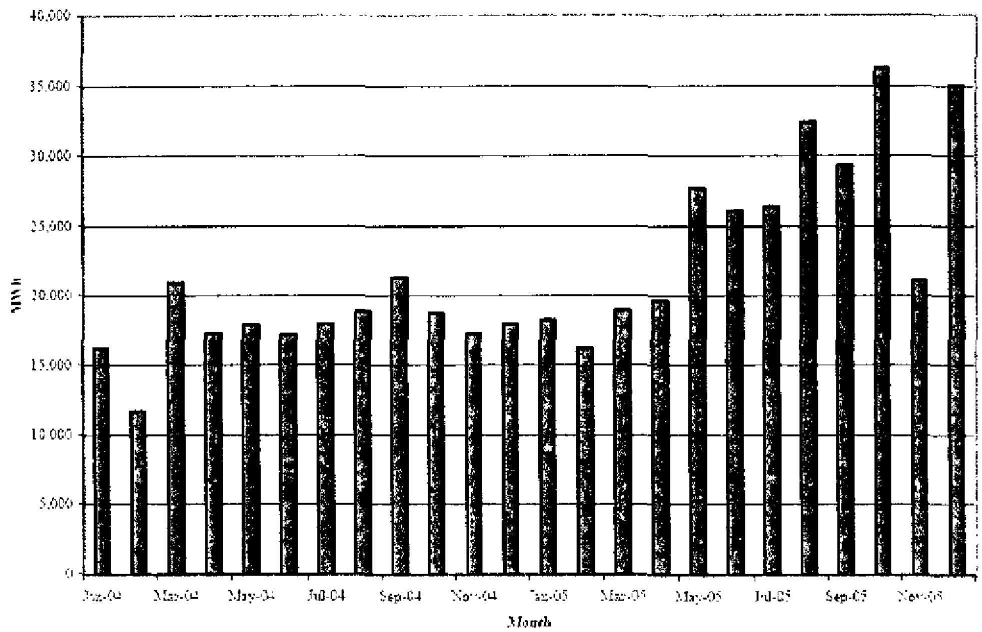
MONTHLY SPP CONFIRMED TRANSMISSION
SERVICE REQUESTS (FREQUENCY) FROM 2004 TO 2005



SOURCE: SPP OASIS

Figure III-6 Monthly SPP Confirmed Transmission Service Requests (Frequency) from 2004 to 2005

MONTHLY SPP CONFIRMED TRANSMISSION
SERVICE REQUESTS (MWH) FROM 2004 TO 2005



SOURCE: SPP OASIS

Figure III-7 Monthly SPP Confirmed Transmission Service Requests (MWh) from 2004 to 2005

The SPP primarily grants access to the transmission systems of its members based on flowgates designated by the SPP and its members. Transmission elements are designated as flowgates if they have the potential to become overloaded due to power flows on the transmission system. Typically, a flowgate is a pair of transmission lines that includes a limiting element and a contingent element. The amount of power flow permitted over a flowgate is based on the amount of power the limiting element could handle if the contingent element experienced a sudden outage.

Flowgates have separate limits for firm and non-firm transmission service. Non-firm service can be sold up to the total transfer capability limit of a flowgate. Firm service can be sold up to a level equal to the flowgate limit less the Transmission Reliability Margin (TRM) for the flowgate. TRM levels are established based on SPP's reserve sharing requirements, which account for potential generator outages or "contingencies".

One significant change in TRM between 2004 and 2005 is the Fort Smith–Arkansas Nuclear One flowgate, which had a TRM (as a percentage of Summer Emergency Limit) of 57% in 2004, is not even listed as a flowgate in 2005. This is another indication that improvements at Ft. Smith have increased the availability of transmission service at the SPP.

Very limited transmission expansion has occurred in the SPP over the past decade. However, this has changed over the past few years. In 2005, $152 million was spent by SPP members on transmission lines and transformers. In 2006, an additional $90 million is expected to be invested. These investments have had a notable impact by reducing congestion on specific flowgates. In addition, Redbud has funded a $2.3 million upgrade the OG&E Arcadia substation that has increased capacity on the Redbud–Arcadia Flowgate, one of the most congested flowgates in the SPP. The Redbud–Arcadia Flowgate is located in the OG&E Control Area. The project was completed before the summer of 2006 and was intended to improve access of the Redbud Generator to the transmission system. Prior to the project the Redbud–Arcadia flowgate was limited to 1,195 MVA. The flowgate is currently limited to 1,426 MVA which is an increase of 231 MVA.

In late 2004, OG&E began construction on a new transformer to its Fort Smith interconnection with Entergy's 500 kV system in order to enhance connectivity with the SERC and satisfy one of the FERC conditions for approval of the McClain acquisition. This, and related upgrades, were completed in the first half of 2005. These upgrades are intended to reduce market power concerns by improving the connectivity of the bulk electrical system.

Transmission improvements at the SPP have, in general, increased the availability of transmission access. More specifically the improvements made at Arcadia substation allowed for a purchase by OG&E of 440 MW in the summer of 2006. The same transmission request for 440 MW of transmission access from Redbud to OG&E was denied in 2005 due to transmission constraints. The transmission improvements at the Fort Smith substation resulted in transmission loading relief (TLR) occurrences to change from 21 incidents in 2003 before the improvements were made to zero incidents in 2005 after improvements were made.

E. Regulatory and Legislative Drivers

OG&E's resource plan is driven by existing regulatory and legislative requirements in a number of areas. OG&E is subject to regulation in all major areas of its business operations including the prices paid for services rendered, major investments in generation, transmission and distribution facilities, operations of its fleet of power plants, reliability, environmental impacts, and the health and safety of its workforce. Several federal and state agencies have the authority over OG&E's business including the OCC, the Arkansas Public Service Commission (APSC), the FERC, the NERC, the Environmental Protection Agency (EPA), and state environmental agencies.

Potential changes to regulatory and legislative mandates are also a source of uncertainty regarding the future, particularly because these changes can be very difficult to predict. This subsection presents a summary discussion of the potential impact that regulatory agency activities may have on OG&E's resource plan.

1. State Utility Commissions

OG&E is regulated at the state level by the OCC and APSC. Both agencies have the authority to review the prudence of major investments and purchase contracts. Oversight of these actions includes a determination of the recovery of associated capital and operating expenses from customers.

In early 2006, the OCC implemented a new set of IRP rules to oversee the resource planning process, leading to this initial submittal by OG&E. Also in early 2006 the APSC developed proposed Resource Planning Guidelines. To date the APSC rules have not been finalized but OG&E submits this IRP based on its assessment that it would meet the proposed guidelines.

2. FERC

The FERC must approve all wholesale transactions that involve the transmission of electricity in interstate commerce including the purchase or sale of generation assets in excess of $10 million. Most recently, upon review and approval of OG&E's acquisition of the McClain facility, the FERC ordered substantial market power mitigation actions resulting in the expansion of OG&E's electric transmission system. The total cost of these upgrades to improve the transmission system was approximately $18 million.

The FERC also regulates the SPP and other RTOs, establishing the terms and conditions for transmission and other services provided by the SPP, and oversees the performance of the SPP markets through the appointment of an independent market monitor. The FERC also reviews wholesale purchase power contracts entered into by OG&E as well as OG&E's transmission tariffs. As described in the following section, Congress has recently granted the FERC additional authorities that are intended to facilitate investments in transmission.

While OG&E has satisfied FERC's market power concerns associated with the McClain transaction, the potential for incremental mitigation measures will need to be reflected when evaluating resource options.

3. NERC

The NERC's historical mission has been to ensure that the bulk electric system in North America is reliable, adequate and security based on voluntary compliance of reliability standards by electric utilities. Thus, the NERC has set standards for the reliable operation and planning of the bulk electric system and monitors compliance with these standards.

This voluntary system is being replaced by a mandatory system of reliability standards under terms established in the Energy Policy Act of 2005 (EPACT 2005). On July 20, 2006, the FERC approved the NERC's application to become the Electric Reliability Organization (ERO) for the United States. The NERC is working to gain similar recognition by governmental authorities in Canada and Mexico. As the ERO, the NERC will have legal authority to enforce reliability standards on all owners, operators, and users of the bulk power system, rather than relying on voluntary compliance.

One potential outcome that would have an impact on OG&E's resource plan is modification of reliability standards. It is conceivable that more stringent standards will affect transmission and generation capacity. However, it is too early to speculate what changes could be considered. Therefore, the resource plan assumes that the existing standards will remain in effect.

4. EPACT 2005

The EPACT 2005, enacted into law on August 8, 2005, includes several provisions that could have an impact on the development of generation and transmission facilities. The most relevant provisions are:

- A provision that allows the U.S. Department of Energy (DOE) to designate "national interest electric transmission corridors" with the ability for the FERC to grant necessary rights of way, providing for comparable powers that the FERC currently has with respect to the siting of interstate natural gas pipelines. The FERC is also empowered to act as the coordinating agency where multiple authorizations are required to construct a transmission facility;
- A provision that allows three or more contiguous states to enter into an interstate compact to establish a regional transmission siting agency;
- Extension of the renewable energy production tax cut and extension from five to ten years of the eligibility for biomass, geothermal, small irrigation, landfill gas, and municipal solid waste projects;
- Incentives for development of clean coal technologies, including Integrated Gasification Combined Cycle (IGCC); and
- Provisions that enable the FERC to designate an agency to develop and enforce bulk power system reliability standards.

It should also be noted that many provisions require subsequent funding by Congress in order to become effective.

OG&E does not foresee a major impact from the EPACT 2005 on its resource plan at this time other than the extension of investment tax credits for wind power. The extension of these tax credits facilitated OG&E's recent commitment to the Centennial Wind Farm, with benefits accruing to customers. Siting requirements for construction of transmission facilities, while subject to a lengthy review process, has not been a major obstacle in this region as it is in other parts of the country.

5. Environmental Regulation

Environmental regulation has a significant impact on the planning, development and operation of OG&E's resource portfolio. Fairly dramatic changes to environmental regulation occurred over the past three decades through passage of the Clean Air Act (CAA) in 1970, and as amended in 1990. As provided for under the amended CAA, the federal government (through the EPA), establishes standards that must be met and provides for certain market and other mechanisms to achieve the standards, while leaving significant implementation actions to state authorities, including the Oklahoma

Department of Environmental Quality (ODEQ) and the Arkansas Department of Environmental Quality (ADEQ). As discussed below, the EPA continues to issue new regulations that impact OG&E and other electric utilities.

The original 1970 CAA authorized the EPA to establish National Ambient Air Quality Standards (NAAQS) to limit levels of pollutants in the air. The EPA has promulgated NAAQS for six criteria pollutants: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone, lead, and particulate matter (PM_{10}). The 1990 Amendments extended the boundaries of serious, severe, or extreme ozone or CO nonattainment areas located within Metropolitan Statistical Areas (MSAs) or Consolidated Metropolitan Statistical Areas (CMSAs). They also modified the standards used to qualify more plants as "major sources" and thus subject to retrofitting or offset provisions and established New Source Performance Standards (NSPS) that apply to power plant development. The 1990 amendments created a market system for SO_2 allowances and required all plants to obtain operating permits. The Clean Air Act has wide-ranging implications for the development and operation of both coal-fired and natural gas-fired power plants. OG&E expects that any necessary environmental expenditure will qualify as part of a pre-approved plan to handle state and federally mandated environmental upgrades which will be recoverable under Oklahoma State House Bill 1910.

a. Sulfur Dioxide

The 1990 CAA includes an acid rain program to reduce SO_2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance is worth one ton of SO_2 released from the smokestack. Plants may only release as much SO_2 as they have allowances. Allowances may be banked and traded or sold nationwide.

Beginning in 2000, OG&E became subject to more stringent SO_2 emission requirements in Phase II of the acid rain program. The EPA allocated SO_2 allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. These lower limits have not had a significant financial impact due to OG&E's reliance on low sulfur coal. In each of the years since 2000, OG&E's SO_2 emissions were well below the allowable limits. This enabled OG&E to sell 3,700 annual allowances for approximately $5.7 million in December 2005. In February 2006, OG&E sold 6,312 annual allowances for approximately $8.9 million, of which OG&E retained 10 %; OG&E will also retain 10% of the proceeds from all future sales of allowances. The remaining revenues from these transactions are flowed through to customers under the fuel clause.

More recently, on March 10, 2005, the EPA published the Clean Air Interstate Rule (CAIR). This rule is intended to control SO_2 and NO_X emissions from utility boilers in order to minimize the interstate transport of air pollution. The state of Oklahoma is not listed as one of the states affected by the rule.

b. Nitrogen Dioxide

Under the acid rain program, OG&E committed to meeting a 0.45 lbs/million British thermal unit (MMBtu) NO_X emission level in 1997 on all coal-fired boilers. As a result, OG&E was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. OG&E's average NO_X emissions from its coal-fired boilers for 2005 were approximately 0.33 lbs/MMBtu. The regulations require that OG&E achieve a NO_X emission level of 0.40 lbs/MMBtu for these boilers beginning in 2008. Further reductions in NO_X emissions could be required if, among other things, legislation is enacted or if a study currently being conducted by the state of Oklahoma determines that such NO_X emissions are contributing to regional haze and that OG&E's facilities impact the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma becomes non-attainment with the fine particulate standard.

c. ODEQ Permitting

The ODEQ CAA Amendment Title V permitting program was approved by the EPA in March 1996. By March of 1997, OG&E had submitted all required permit applications. As of December 31, 2005, OG&E had received Title V permits for all of its generating stations. Since these permits require renewal every five years, OG&E has begun the renewal process for some of its generating stations. Air permit fees for generating stations were approximately $0.6 million each in 2005 and in 2006. The fees for 2007 are estimated to be approximately the same as in 2006.

d. Mercury

On March 25, 2005, the EPA issued the Clean Air Mercury Rule (CAMR) to limit mercury emissions from coal-fired boilers. The CAMR is currently subject to legal challenges. The CAMR requires reductions in mercury in two phases, Phase I beginning in 2010 and Phase II in 2018. The CAMR is based on the cap and trade program that will allow utilities to purchase mercury allowances (if available) rather than reduce emissions. It is anticipated that OG&E will need to obtain allowances or reduce its mercury emissions in Phase II by approximately 70 percent. The CAMR requires each state to adopt the requirements of the federal rule into a state implementation plan. However, the CAMR does not preclude states from developing more stringent mercury reduction requirements. The state of Oklahoma is currently in the process of implementing the rule and is seeking input from affected utilities on how the allowances should be allocated. OG&E is participating in the rulemaking process and anticipates the rulemaking to be completed by the end of 2006. The cost to install any mercury controls is uncertain at this time but is expected to be significant to meet Phase II requirements in 2018. The state implementation plan will also require continuous monitoring of mercury emissions from OG&E's coal-fired boilers beginning in 2009. The cost of installation of mercury monitors is estimated at $4,500,000.

e. Ambient Ozone, Fine Particulates and Visibility

In 1997, the EPA finalized revisions to the ambient ozone and fine particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, the EPA has designated Oklahoma "in attainment" with both standards. However, both Tulsa and Oklahoma City have recently experienced high levels of ozone. If Tulsa and Oklahoma City continue to have elevated ozone levels during upcoming ozone seasons, they could face redesignation to non-attainment status. To help avoid redesignation, both Tulsa and Oklahoma City have entered into an "Early Action Compact" with the EPA whereby voluntary measures will be enacted to reduce ozone.

On April 25, 2005, the EPA published a finding that all 50 states failed to submit the interstate pollution transport plans required by the CAA as a result of the adoption of the revised ambient ozone and fine particle standards. Failure to submit these implementation plans began a two-year timeframe, starting on May 25, 2005, during which states must submit a demonstration to the EPA that they do not affect air quality in downwind states. Recent communications with the ODEQ indicate that they expect to be able to demonstrate no impact on other states and meet the May 25, 2007 deadline established by the EPA. Therefore, there should be no significant impact to OG&E as a result of the April 25, 2005 finding.

However, on December 21, 2005, the EPA proposed lowering the 24-hour fine particulate ambient standard while retaining the annual standard at its current level. In addition, the EPA proposed a new standard for coarse particulates. Based on past monitoring data, it appears that Oklahoma may be able to remain in attainment if the standards are finalized as proposed. However if parts of Oklahoma do become "non-attainment", reductions in emissions from OG&E's coal-fired boilers could be required which may result in significant capital and operating expenditures.

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. These regulations are intended to protect visibility in national parks and wilderness areas ("Class I areas") throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the regulation. However, Oklahoma's impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. The state of Oklahoma has joined with eight other central states and has begun to finalize the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas.

In September 2005, the ODEQ informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Class I areas. OG&E and other affected industries in Oklahoma initiated a modeling study. Because the preliminary results indicate a significant impact from OG&E's Sooner, Muskogee, Seminole, and Horseshoe Lake generating stations on visibility in Class I areas in both Oklahoma and Arkansas, Best Available Retrofit Technology (BART) must be applied. OG&E must submit its proposed controls to the ODEQ by March 2007. OG&E will have five years from the date of approval of a compliance plan by the EPA to institute any required reductions. OG&E anticipates a significant financial expenditure to comply.

f. Carbon Dioxide

There have been a variety of unsuccessful legislative and litigation efforts to force mandatory control of utility emissions that allegedly contribute to climate change. If legislation is passed in the future requiring mandatory CO_2 emission reductions to address climate change, this could have a tremendous impact on all coal-fired electric utilities, including OG&E's operations by requiring OG&E to significantly reduce the use of coal as a fuel source.

g. Water

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. The EPA 316(b) rules for existing facilities became effective July 23, 2004. OG&E has engaged a consultant who has developed the required documentation for four OG&E facilities. These documents were submitted to the state agency on December 7, 2005 for review and approval. OG&E has also provided the state of Oklahoma with information and requests that, if approved by the state, may reduce the impact of the 316(b) rules on OG&E because if the OG&E's position is approved, three of the four OG&E facilities would not be required to comply with the 316(b) rules. Depending on the ultimate analysis and final determinations regarding the 316(b) rules, capital and/or operating costs may increase at any affected OG&E generating facility.

The impacts of uncertainty attributable to potential changes to environmental policies are described in Section V.

IV. Analysis of OG&E's Resource Options

The next step in developing a Resource Strategy is the analysis of supply-side and demand-side resources to satisfy anticipated load growth. The analysis is conducted by employing a sophisticated model to select an optimal portfolio that minimizes the total costs of all resources, including existing resources. Existing resources must be reflected because of potential impacts of new resources on the utilization of the existing asset base. Additionally, it is possible that the optimal resource portfolio will call for retirement of certain existing resources.

This section describes the modeling approach, identifies the potential resource additions, and presents the modeling results, including an analysis of potential risks associated with various portfolios. The Resource Strategy presented in Section V is largely based on these results.

A. Modeling Approach and Inputs

As shown in Figure IV-1 on the following page, two resource optimization models are used to analyze resource options and portfolios. CEM is used to develop an optimal resource portfolio based on a set of "Base" assumptions regarding energy demand, fuel prices, and the characteristics of existing and potential resource alternatives. The optimal strategy is the one that minimizes total net present value of revenue requirements (NPVRR), including both capital costs and production costs, over the 30-year study period. The optimal strategy is also based on maintaining a 12% reserve margin. Next, CEM is used to develop similar optimal resource portfolios based on alternative sets of assumptions or "planning cases" as described later in this section. Although these portfolios are optimized based on a 30-year horizon, the results are presented for a 10-year period (2007-2016).

The Planning and Risk application (PAR) is used to evaluate the impact on total revenue requirements of alternative assumptions by performing a stochastic analysis using distributions of potential values for key input variables including fuel and electricity prices. Thus, the PAR results are used to identify the revenue requirement exposure of the optimal resource portfolio to the distribution of key input variables. PAR was used to examine the impact on both the Base Case and alternative planning cases. CEM and PAR were developed by Global Energy Decisions and are described in more detail in Appendices J and K, respectively.

Finally, the Resource Strategy is developed by applying OG&E judgment and experience to these model results.

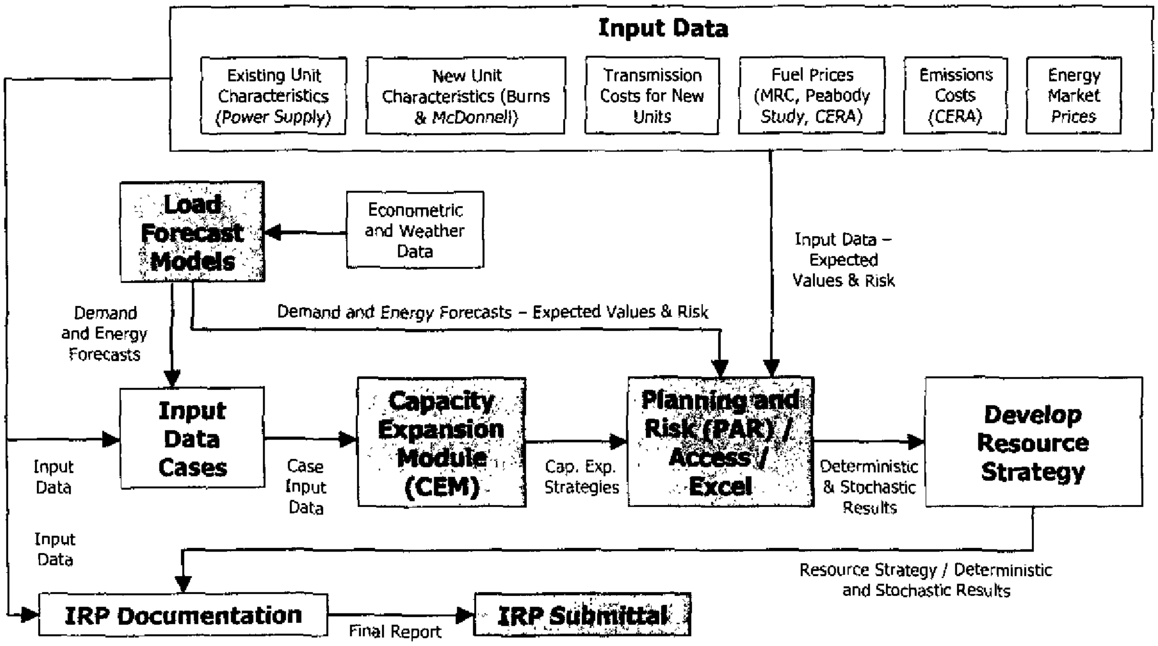


Figure IV-1 2006 IRP Analysis Process

The major inputs to the CEM and PAR models are also shown in Figure IV-1. These inputs are described briefly below with details provided in appendices:

1. **Demand and Energy Forecast:** forecast of demand and energy based on a load forecast model (described in Section II.C, with details in Appendix B)
2. **Existing unit characteristics:** capacity availability and capital and operating costs associated with OG&E's existing portfolio (described in Section IV.A.1.b)
3. **New resource characteristics:** capacity availability and capital and operating costs associated with new resource options, including any transmission investments that may be required (described in Section IV.A.1 below)
4. **Fuel Prices:** projection of natural gas and coal prices (described in Section IV.A.2.c) from sources including Cambridge Energy Research Associates (CERA) and OG&E's Market Risk Committee (MRC)
5. **Emissions costs:** assumptions regarding tax and/or other costs attributable to SO_2, NO_X, CO_2, and mercury
6. **Regional energy market prices**: projection of SPP market clearing prices for purchases and sales of economy energy

1. Specification of Resource Alternatives

CEM will select the optimal resource portfolio from among the supply and demand-side *resources that are specified.* Thus, OG&E specified a set of potential resources that included baseload, intermediate and peaking plants, wind farms, and demand-side resources. In each case, OG&E specified the operational characteristics of the resource, including its anticipated contribution to capacity at the time of peak demand, and the associated fixed and variable non-fuel O&M costs of constructing and operating the resource. OG&E also specified the first year in which the resource would be available, depending on the lead-time required for construction. Once available, a resource remained available as a resource option in subsequent years.

a. Resources Evaluated Using CEM and PAR

OG&E contracted with Burns & McDonnell to perform a generation technology assessment for use in this resource plan. OG&E and Burns & McDonnell worked together to develop a list of potential resource options that encompassed the range of fuel sources, technologies, and capacities that merit evaluation. As discussed below, certain technologies were not deemed to be realistic alternatives for OG&E at this time.

Burns & McDonnell then developed operating and cost assumptions for each of the following technologies:

- Baseload Alternatives:
  - 250 MW Subcritical Pulverized Coal (Sub-PC)
  - 500 MW Subcritical Pulverized Coal
  - 750 MW Subcritical Pulverized Coal
  - *900 MW Subcritical Pulverized Coal*
  - 365 MW Supercritical Pulverized Coal (Super PC, assumes partial ownership share of 950 MW unit)
  - 750 MW Supercritical Pulverized Coal
  - 900 MW Supercritical Pulverized Coal
  - 250 MW Subcritical Atmospheric Fluidized Bed (AFBC)
  - 2 x 300 MW Subcritical Atmospheric Fluidized Bed
  - 500 – 600 MW Integrated Coal Gasification Combined Cycle (IGCC)
- Intermediate Load Alternatives:
  - 250 MW Combined Cycle (CC) (1x1 GE 7FA)
  - 280 MW Combined Cycle (1x1 GE 7FB)
  - 500 MW Combined Cycle (2x1 GE 7FA)
- Peaking Load Alternatives:
  - 45 MW Simple Cycle (CT) (1x GE LM6000PC-Sprint)
  - 80 MW Simple Cycle (1x GE 7EA)
  - 100 MW Simple Cycle (1x GE LMS100)
- Renewable Energy / Demand Side Management (DSM) Alternatives:
  - 80 MW Wind Turbine Farm
  - 10 MW Demand Side Management (Load Curtailment)
- Upgrade Alternatives:
  - 48 MW Enid

Potential retirement of existing resources was also subject to CEM optimization. All gas units were considered for either mothballing or retirement in all years.

As noted above, certain resource options were not deemed to be realistic alternatives during the 10-year planning horizon due to technical and/or economic factors. These technologies include nuclear, solar-based technologies, biomass-fueled units, waste-to-energy units, geothermal (hydrothermal type consisting of reservoirs of steam or hot water) technologies, hydropower units, and ocean-related technologies. These technologies were not evaluated in this IRP for the following reasons:

- **Nuclear:** while nuclear energy is being discussed once again as a potential technology, new units will likely be constructed by a relatively small handful of entities that are consolidating ownership of the nation's existing fleet. A PPA option based on a new nuclear unit may become a viable option in a future IRP but is not a viable option at this time.
- **Solar-based technologies:** solar-based technology is a viable demand-side resource, but is not a viable source for utility-developed central stations
- **Biomass-fueled units:** not a viable utility-developed option due to the lack of an economic source and relatively low fuel heating value
- **Waste-to-energy units:** not a viable utility-developed option due to the lack of an economic source and relatively low fuel heating value
- **Geothermal technologies:** lack of proximity to a suitable geothermal resource (hydrothermal type)
- **Hydropower units:** lack of proximity to a suitable hydropower resource
- **Ocean-related technologies:** lack of proximity to an ocean resource

b. Model Input Assumptions

Table IV-1 summarizes the following input data for the new capacity resources listed above:

- Net plant output (kW) at 100% load
- Net plant heat rate (Btu/kWh) at 100% load
- Capital cost (2006 \$/kW)
- Fixed O&M cost (2006 \$/kW-yr)
- Variable O&M cost (2006 \$/MWh)
- Project schedule (months)
- First year available (June 1 availability); also available in subsequent years

Technology	Net Plant Output (kW) at 100% load	Net Plant Heat Rate (Btu/kWh) at 100% load	Capital Cost (2006 $/kW)	Fixed O&M Cost (2006 $/kW-yr)	Variable O&M Cost (2006 $/MWh)	Project Schedule (months)	First Year Available
Baseload Alternatives							
250 MW Sub-PC	250,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
500 MW Sub-PC	500,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
750 MW Sub-PC	750,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
900 MW Sub-PC	900,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
365 MW Super-PC	365,000	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
750 MW Super-PC	750,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
900 MW Super-PC	900,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
250 MW AFBC	250,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Technology	Net Plant Output (kW) at 100% load	Net Plant Heat Rate (Btu/kWh) at 100% load	Capital Cost (2006 $/kW)	Fixed O&M Cost (2006 $/kW-yr)	Variable O&M Cost (2006 $/MWh)	Project Schedule (months)	First Year Available
2x300 MW AFBC	600,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
500 – 600 MW IGCC	570,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Intermediate Load Alternatives							
250 MW CC (1x1 GE 7FA)	247,660	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
280 MW CC (1x1 GE 7FB)	264,510	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
500 MW CC (2x1 GE 7FA)	505,920	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Peaking Load Alternatives							
45 MW CT (1x GE LM6000)	46,810	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
80 MW CT (1x GE 7EA)	80,500	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
100 MW CT (1x GE LMS100)	101,670	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Renewable Energy / DSM Alternatives							
80 MW Wind Turbine Farm	80,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10 MW DSM	10,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Alternatives:							
48 MW Enid	48,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table IV-1 New Capacity Resource - Summary of Input Data

Although fuel cost differentials are not shown in this table, it does show the difference in capital costs within each resource classification. For example, OG&E's 42.5% ownership of a 950 MW supercritical pulverized coal plant has significantly lower capital costs than other baseload options. It is not very meaningful to compare different types of resources without examining fuel costs.

c. Transmission Cost Assumptions

Certain supply-side resource options will require transmission investments, a fact that must be reflected in the optimization model. However, the cost estimates above are not site-specific. To address this, OG&E has identified a number of potential future power plant sites and estimated based its estimates of transmission costs on the use of these sites. Formal site studies will be performed, and cost estimates refined, when any specific resource option enters the development phase.

Table IV-2 identifies ten sites that were chosen based upon existing infrastructure, gas pipeline locations, and existing transmission lines.

Site No.	Site Description	Resource Type	County
1	Sooner Power Plant	1 - 950 MW Coal Unit	Noble
2	Ardmore	2 - 102 MW CTs	Carter

Site No.	Site Description	Resource Type	County
3	Horseshoe Lake Power Plant	1 - 102 MW CT	Oklahoma
4	Seminole Power Plant	1 - 102 MW CT	Seminole
5	Mustang Power Plant	4 - 102 MW CTs	Canadian
6	McClain Power Plant - 345KV	1- 500 MW CC	McClain
7	Mustang Power Plant	1- 500 MW CC	Canadian
8	Elk City	2 - 80 MW Wind	Beckham
9	Woodward	2 - 80 MW Wind	Woodward
10	Mooreland	2 - 80 MW Wind	Woodward

Table IV-2 Sites for Future Generation Resources

Transmission system analysis was preformed to estimate the transmission expansion cost associated with possible construction of new generation assets at each of the site locations identified in Table IV-2. Of course, the siting of any new generation or transmission facility will affect the performance of OG&E's entire transmission network and may also have impacts that extend beyond OG&E's service territory. Thus, in order to derive reasonable estimates of transmission costs for purposes of the IRP, OG&E examined five hypothetical expansion plans.

The first expansion plan included a new 950 MW coal plant located at the Sooner Power Plant located in OG&E's Noble County service territory. The proposed point of interconnection is on the existing Sooner 345 KV bus at the Sooner substation.

Power flow analysis indicates that transmission upgrades will be required to accommodate this new generation resource. The new plant creates network constraints in the OG&E system that can be addressed by adding sixty-five miles of 345 KV line from Sooner power plant to Arcadia substation at an estimated cost of [redacted]. There are additional network constraints in AEPW, GRDA, WFEC, and Westar Energy (WERE). The total estimated cost of network upgrades is [redacted]. In addition, the estimated cost of adding 345 KV Direct Assignment Interconnection facilities in the Sooner substation is [redacted]. Thus, the total estimated cost to connect 950 MW of additional generation at the Sooner 345 KV station is [redacted].

The second expansion plan involved eight CTs, two of which are located in Ardmore, one at Horseshoe Lake Power Plant, one at Seminole Power Plant, and four at Mustang Power Plant. Horseshoe Lake Power Plant is located near Harrah, Oklahoma County, Oklahoma. Mustang Power Plant is located in Mustang, Canadian County, Oklahoma. Seminole Power Plant is located near Konowa, Seminole County, Oklahoma. All eight sites for the CTs are located in the OG&E Service Territory.

Power flow analysis for the second expansion plan indicates that a minor transmission upgrade will be required to add the eight 102 MW CTs of additional generation. Two of the CTs will be located in Ardmore, one at Horseshoe Lake, one at Seminole and four at Mustang. The network constraint in the OG&E System can be addressed at an estimated cost of [redacted]. The estimated interconnection cost for each CT will be [redacted]. Thus, the total estimated cost to connect 8 CTs to the OG&E system is [redacted].

The third expansion plan includes the previously mentioned eight CTs and one 500 MW CC located at the McClain Power Plant. McClain is located in McClain County, Oklahoma in the OG&E Service Territory.

Power flow analysis for the third expansion plan indicates that transmission upgrades will be required to add the eight CTs and one 500 MW CC at the McClain power plant. First, there are network constraints on the OG&E system and one on the WERE system that can be addressed at an estimated cost of [redacted]. A new 345 KV bus will also be required at Earlywine substation and at McClain power plant, along with a bus tie transformer at Earlywine substation. In addition, 2.25 miles of new 345 KV line will be required between Earlywine substation and McClain power plant. These requirements for the 345 KV system are estimated to cost [redacted]. The 500 MW CC will require a generator step up transformer at an estimated cost of [redacted]. The estimated cost to connect one 500 MW CC at McClain is [redacted]. The estimated interconnection cost to connect the eight CTs is [redacted]. Thus, the total estimated cost for the third expansion plan is [redacted].

The fourth expansion plan includes the previously mentioned eight CTs, one 500 MW CC at McClain, and one 500 MW CC located at the Mustang Power Plant.

Power flow analysis for the fourth expansion plan indicates that transmission upgrades will be required to add the eight CTs and two 500 MW CCs with one at the McClain power plant and one at Mustang power plant. There are network constraints in the OG&E and one constraint in the WERE system that can be addressed at an estimated cost of [redacted]. A new 345 KV bus will also be required at Earlywine substation and at McClain power plant, along with a bus tie transformer at Earlywine substation. In addition, 2.25 miles of new 345 KV line will be required between Earlywine and McClain. These requirements for the 345 KV system are estimated to cost [redacted]. Each of the 500 MW CCs will require a generator step up transformer at an estimated cost of [redacted]. The total estimated cost to connect the two 500 MW CCs is [redacted]. The estimated interconnection cost to connect the eight CTs is [redacted]. Thus, the total estimated cost for scenario four is [redacted].

A fifth_analysis was performed for the purpose of analyzing additional wind resources and sites for the purpose of identifying cost for the resource plan. Six blocks of wind of 80 MW each were analyzed with each additional block being added to the first for a total of 480 MW of wind. The first two blocks of wind were added at Elk City in Beckham County, Oklahoma. The next two blocks were added at Woodward in Woodward County, Oklahoma. The last two blocks were added at Mooreland which is also located in Woodward County, Oklahoma.

Power flow analysis for the wind option indicates that transmission upgrades will be required to add additional wind to the OG&E System. There are network constraints in the OG&E system that can be addressed at an estimated cost of [redacted]. There are additional network constraints in AEPW and WFEC and they can be addressed at an estimated cost of [redacted]. The costs for each block for the network constraints in OG&E and the other control areas are shown in Table IV-3. The total estimated cost to correct all network constraints is [redacted].

Block	Transmission Upgrade Costs		
	OKGE	Other Control Areas	Total
80 MW	[redacted]	[redacted]	[redacted]
160 MW	[redacted]	[redacted]	[redacted]
240 MW	[redacted]	[redacted]	[redacted]
320 MW	[redacted]	[redacted]	[redacted]
400 MW	[redacted]	[redacted]	[redacted]
480 MW	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

Table IV-3 Wind Blocks - Network Constraints Estimated Cost

The transmission costs for all expansion plans are summarized in Table IV-4 below. There may be additional stability costs that will be determined in the SPP Study Process.

Scenario	Total Estimated Cost
1 950 MW Coal Plant at Sooner	[redacted]
8 CTs - 2 in Ardmore, 1 at HLS, 4 at Mustang, 1 at Seminole	[redacted]
8 CTs and 1 500 MW CC at McClain on 345KV side	[redacted]
8 CTs and 1 500 MW CC at McClain on 345KV side and 1 500 MW CC at Mustang	[redacted]
80 MW Wind	[redacted]
160 MW Wind	
240 MW Wind	[redacted]
320 MW Wind	[redacted]
400 MW Wind	[redacted]
480 MW Wind	[redacted]

Table IV-4 Total Estimated Cost for all Expansion Plans

It is important to emphasize that these cost estimates were developed for the analysis of possible new resources for purposes of this IRP. After a decision has been made as to the type and location of the addition of a new resource a request will be made to the SPP to add the new resource as a new network resource. The proposed generation resource will be studied by SPP to assess connection requirements, reliability consequences and potential transmission impacts on neighboring systems. Results of the study will then be used to determine more refined cost estimates.

2. Natural Gas and Coal Price Assumptions

a. Natural Gas Prices

Gas prices will be influenced by changes in domestic productive capacity, the timing of the liquefied natural gas (LNG) regasification build, and the rate of electric and industrial sector gas demand.

Domestic production capacity is likely to remain flat through 2010 and with the North American total gas demand expected to rise, the continental supply will not be adequate to meet demand.

In the past few years, players in the gas industry have taken steps to make LNG more available to the North American market. The anticipated arrival of LNG may put downward pressure on North American prices starting as early as 2008. Until LNG is a significant source of supply, the natural gas market is expected to remain tightly balanced and vulnerable to price spikes.

The highest uncertainty may be the electric sector demand for gas that most likely will be driven by environmental cost. If environmental cost are higher than expected the electric sector demand for gas could experience the growth seen in the first part of the decade.

b. Coal Prices

The SPRB coal reserves are sufficient to supply projected demand for coal as a fuel for the generation of electricity into the foreseeable future. The delivered cost of SPRB coal has been considerably below the historical delivered cost of natural gas, and that trend should continue.

The diminished number of producers in the SPRB continues to be a concern, as fewer firms in one market can (and usually do) influence pricing. Fewer producers translate to higher, more volatile prices, all other things held equal.

The SPRB producers are efficiently producing coal and will continue to improve mining productivity. These efficiencies also will be realized in the production of better quality and cleaner coal in the future. The fact that coal is not as clean a burning fuel as is natural gas reduces the economic differential between the two fuels and creates a potential future problem for coal producers.

Most long-term SPRB coal supply contracts entered into in the 1970's and 1980's have expired. The base revenues that the SPRB producers relied upon to price other coal purchases at incremental price levels are gone. This situation plus the producers' natural inclination to maximize their profits, plus the trend for short-term coal contracts, changes the pricing dynamics of SPRB coal and pushes prices in an upward direction.

A study prepared by L.E. Peabody & Associates, Inc. summarize some of the reasons for the recent spike in PRB coal prices and the reasons why the trend will have reversed itself by the 2011 time period, but not back to the levels realized in the 1990's:

1. The price of natural gas is very high but is projected to decline to the $5 or less per MMBTU range by 2007.
2. Currently, inventories are low at utilities because of PRB service problems caused by insufficient rail track maintenance. Once the maintenance problems are resolved and utility inventories return to more normal levels, the demand for PRB coal will moderate and prices will move downward.
3. The overall economy has been moving at a rapid pace and there are signs of a slow-down on the horizon. A slow-down in the economy will result in a decline in business for the railroads and increase in the rail infrastructure capacity for the railroads' core products, e.g., coal.
4. The capacity to production ratio for PRB coal suggests that the PRB producers have an ample supply of coal to meet the future demand, including projected growth. By adjusting production, the producers can influence pricing in the short term.
5. Environmental regulations and standards such as SO_2 allowances will continue to develop and promote the low-sulfur PRB coal reserves as a viable energy resource, increasing its value. A carbon tax would have the opposite impact.

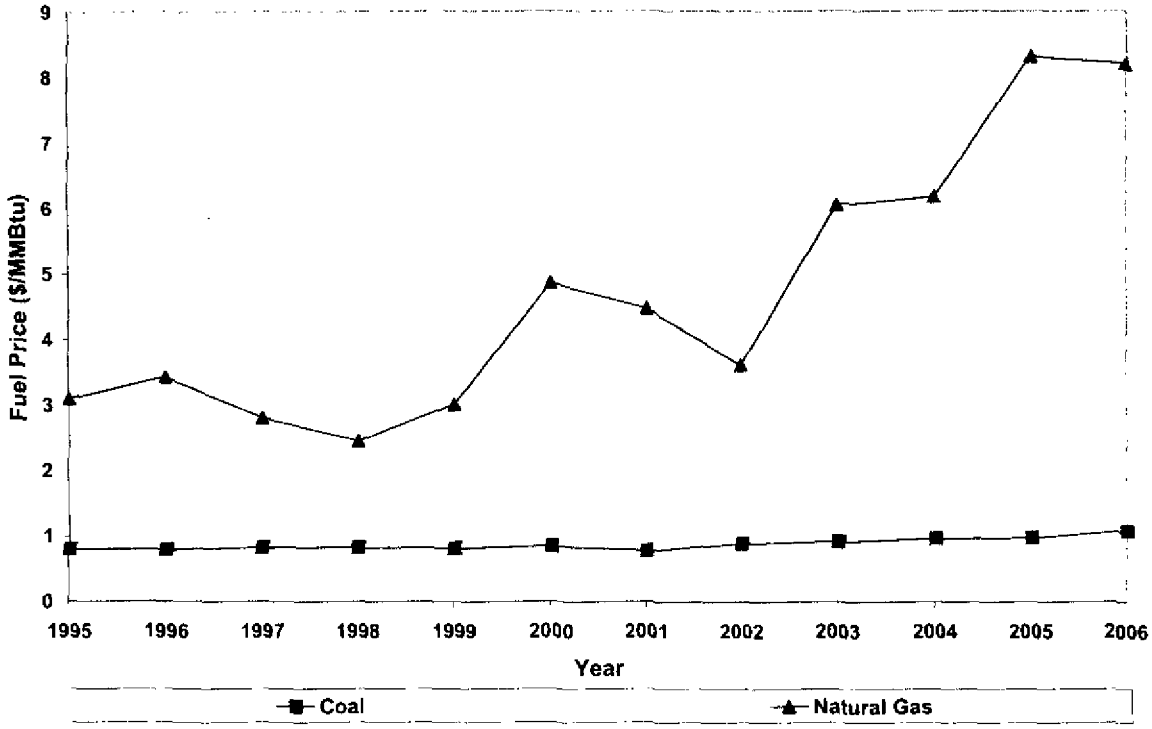
c. Fuels Forecast

OG&E develops a 30-year monthly fuel forecast each year for internal use. The forecast of coal prices is derived from information developed by L. E. Peabody & Associates, Inc., for OG&E. The forecast of natural gas prices is created internally by OG&E and is derived from the following public and private sources:

- Published data:
  - New York Mercantile Exchange (NYMEX)
  - U.S. Energy Information Association (EIA)
- Private data sources:
  - PIRA Energy Group (PIRA)
  - CERA
- Internally-developed forward basis curves.

OG&E forecasts the price of natural gas delivered to OG&E's power plants by adding together three components: (1) Henry Hub price, (2) a basis differential to develop a Mid-Continent price, and (3) transportation from a Mid-Continent delivery point to OG&E's plants.

As shown in Figure IV-2, North American natural gas prices have been increasing over the past decade as the balance between natural gas demand and supply has tightened and as the prices of crude oil and refined products have increased. For the last 10 years, the electric industry has been building natural-gas-fired plants almost exclusively because gas was cleaner and the price was attractive. With an estimated 90 percent of all new power plants recently built being fueled by natural gas, demand for gas is expected to grow dramatically in coming years. Continued growth in demand for natural gas is outpacing the production from both domestic suppliers and Western Canadian supply basins.



Source: FERC Form 1, EIA-412, RUS-12, EIA-906, and Global Energy Primary Research

Figure IV-2 Historical OG&E Fuel Prices

In contrast, as shown in Figure IV-2, the U.S. in recent years has seen stable coal prices relative to surging natural gas prices. All of OG&E's coal-fired units are designed to burn low-sulfur western coal. OG&E currently purchases about 90 percent of its coal under long-term contracts expiring in years 2010 and 2011. During 2005, OG&E purchased approximately 9.2 million tons of coal from the SPRB. In 2005, a series of derailments delayed coal shipments from the SPRB in Wyoming. The delays have cut into coal supply inventories at many coal-fired power plants around the country.

Table IV-5 summarizes the OG&E fuel forecast for 2007 through 2036.

	Coal $/MMBtu (Delivered)	Natural Gas $/MMBtu (Wellhead)
1st 5 Year Average	$1.04	$6.03
2nd 5 Year Average	$1.04	$4.46
3rd 5 Year Average	$1.03	$4.93
4th 5 Year Average	$1.07	$5.60
5th 5 Year Average	$1.12	$6.14
6th 5 Year Average	$1.19	$6.29

Table IV-5 Fuel Forecast 2007 - 2036 (Real 2006 $)

3. Environmental Regulation Impact on the Resource Plan

The economic impact of controlling air pollutants is reflected in the analytical modeling. In summary, the modeling assumes: (1) that there will be no emission control equipment installed on OG&E's existing generating units and (2) all new units reflect costs that are based on compliance with Best Available Control Technology (BACT) and comply with all regulatory requirements presently in place.

If environmental rules change there could be significant cost implications, including the impact of additional capital expenditure or compliance credits. The new units were assigned estimated additional costs based on the following emissions control equipment installed:

- Pulverized coal unit (subcritical and supercritical):
  - SO_2: scrubber.
  - NO_X: SCR.
- CT units:
  - SO_2: not required.
  - NO_X:
    - GE 7EA – Dry Low NO_X combustors.
    - GE LM6000 and LMS100 – water injection.
- CC units:
  - SO_2: not required.
  - NO_X: SCR.

B. Screening Analysis Using CEM

This section discusses the use of CEM to perform screening analyses for both the Base Case and the alternative planning cases.

1. Base Case Analysis Using CEM

As described in Section IV.A, the first resource planning analysis involves use of the CEM model to analyze the Base Case. This case is based on a set of "most likely" assumptions for factors that are largely beyond OG&E's control. These assumptions are summarized in Table IV-6.

Assumption Name	Assumption Value
Demand Forecast	Peak demand grows at 1.76% per year; energy at 1.66%
Fuel Prices	Average fuel prices (2006 $/MMBtu): natural gas = 5.25, coal = 1.08
Emissions Costs	No CO2 tax or mercury-related costs
SPP EIS Market	Purchase 200 MW of 8,000 Btu/kWh natural gas-fired capacity

Table IV-6 Base Case Assumptions

Table IV-7 below presents the optimal 10-year capacity expansion strategy produced by CEM for the Base Case.

In summary, the Enid combustion turbines (48 MW total) are to be upgraded in 2007, the first year they could be available. Four combustion turbines are to be installed from 2008 through 2010 since they are the only non-renewable resources available during that period. After these combustion turbines, a 365 MW supercritical PC (representing OG&E's share of the proposed jointly-owned 950 MW Oklahoma supercritical PC unit) is to be placed in operation in 2011 and a 900 MW subcritical PC is to be placed in operation in 2014.

Expansion Strategy	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Base Case	Enid	LM6000-1 LMS100-1	LMS100-1	LMS100-1	Super PC-365	None	None	Sub PC-900	None	None
Color Legend (Technology - # of units):										
Gas-Fired Combustion Turbine Units										
Gas-Fired Combined Cycle Units										
Coal-Fired Units										
Renewable (Wind/DSM) Units										
No Units Added										

Table IV-7 Capacity Expansion Strategies (10 years) – Base Case Scenario

2. Alternative Planning Case Analyses Using CEM

OG&E has used scenario and sensitivity analyses for several years in order to reflect uncertainty about the future in planning exercises and activities, including resource planning. As described in Section IV.C, scenarios and sensitivities are one way to examine the risks attributable to potential deviations in key assumptions from Base Case assumptions. In the context of resource planning, they provide a more robust planning approach as it is important to understand the planning implications if key assumptions about the future turn out to be different than anticipated.

a. Planning Case Design

In addition to the Base Case described above, OG&E developed 11 alternative planning cases. Four of these alternative cases are CERA-based scenarios that vary several key assumptions in an effort to create distinct and comprehensive future states. The remaining cases are more aptly termed "sensitivity" cases as they test the impact on the optimal portfolio of constraints on a more limited set of assumptions. These seven sensitivity cases are comprised of two alternative demand cases, four technology-restricted cases, and an SPP market-based case. The CERA scenarios are used by many utilities in their planning process and have been used by OG&E's management for a number of years to improve the overall decision-making process.

These cases are summarized in Figure IV-3. Each case produces an alternative optimal portfolio that can be compared to the Base Case portfolio.

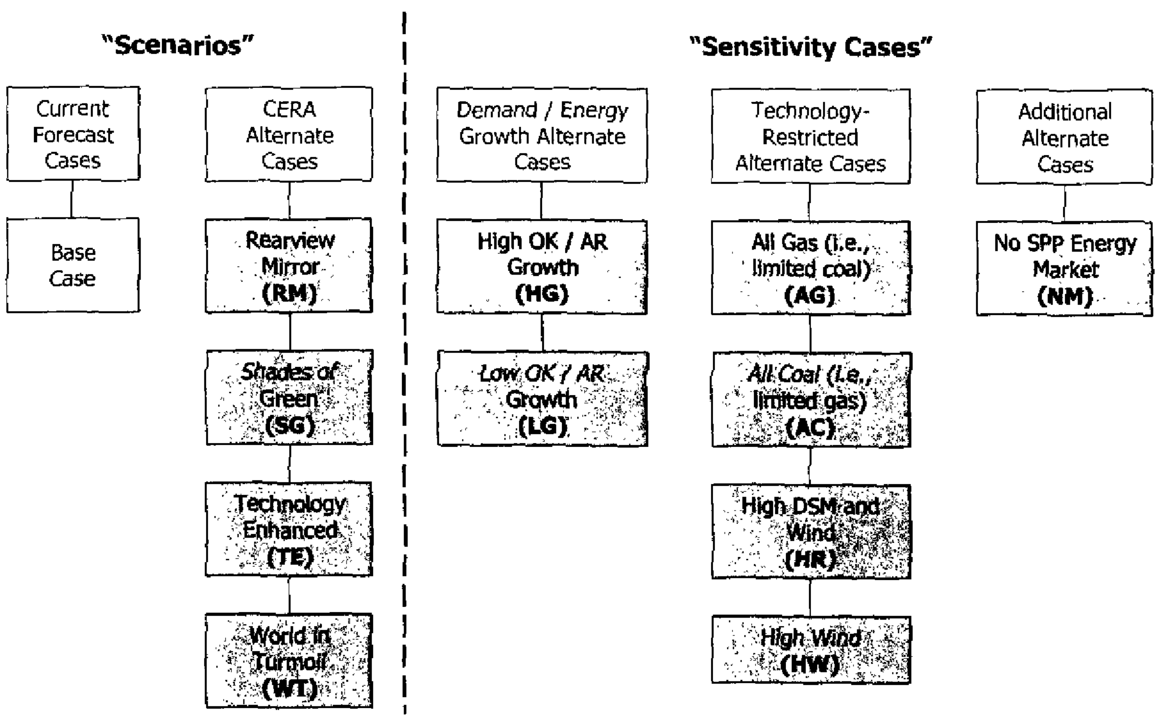


Figure IV-3 Planning Cases

The cases differ greatly in peak demand (Figure IV-4), energy growth (Figure IV-5), the cost of natural gas (Figure IV-6), and environmental requirements (Figures IV-7 through IV-10). The 11 alternative cases and the Base Case are described and compared in more detail below in Table IV-8 (assumption values that do not change from the Base Case are not repeated). In the Base Case and all the alternative cases except for the "No SPP Market" Case, it is assumed that the SPP EIS Market would allow for the purchase of 200 MW of energy from 8,000 Btu/kWh heat rate natural gas-fired units (see modeling approach for the SPP EIS Market as discussed in Section III.D.3).

	Planning Case	Description	Avg. Demand Forecast Growth (%/year)	Avg. Fuel Prices (2006 $/MMBtu)	Additional Emissions Costs
1	Base	Assumptions viewed as most likely to occur	Peak: 1.76% Energy: 1.66%	Gas: $5.25 Coal: $1.08	NO_x: 0 SO_2: 0 CO_2: 0 Hg: 0
2	CERA - "Rearview Mirror"	Muddled electric power regulation, average growth of the U.S. economy, and moderate peak demand growth	Peak: 1.86% Energy: 1.81%	Gas: $4.58	SO_2: >0 Hg: >0
3	CERA - "Shades of Green"	Dominance of environmental issues, moderate growth of the U.S. economy, and slow peak demand growth	Peak: 1.33% Energy: 1.52%	Gas: $5.24	NO_x: >0 SO_2: >0 CO_2: >0
4	CERA - "Technology Enhanced"	Dominance of electrical power deregulation, very strong growth of the U.S. economy, and strong peak demand growth	Peak: 1.90% Energy: 2.17%	Gas: $4.57	NO_x: >0 SO_2: >0 CO_2: >0 Hg: >0
5	CERA - "World in Turmoil"	Volatile energy markets, very slow growth of U.S. economy, and slow peak demand growth	Peak: 1.17% Energy: 1.18%	Gas: $3.53	SO_2: >0
6	High Growth	Strong Oklahoma and Arkansas economies	Peak: 2.01% Energy: 2.40%		SO_2: >0 Hg: >0
7	Low Growth	Weak Oklahoma and Arkansas economies	Peak:: 0.88% Energy: 0.83%		SO_2: >0 Hg: >0
8	All Gas	Legislation precludes new coal plants after 2013 except IGCC; coal plants shut down in 2026			NO_x: >0 SO_2: >0 CO_2: >0
9	All Coal	Legislation precludes use of gas for electric generation after 2013; all plants shut down in 2026			
10	High Wind	Legislation mandates 10% of new generation must be wind			NO_x: >0 SO_2: >0 CO_2: >0 Hg: >0
11	High Wind and DSM	Legislation mandates 10% of new resources must be wind; 10% must be DSM			NO_x: >0 SO_2: >0 CO_2: >0 Hg: >0
12	No SPP Market	SPP energy market does not develop			

Table IV-8 Major Case Assumptions

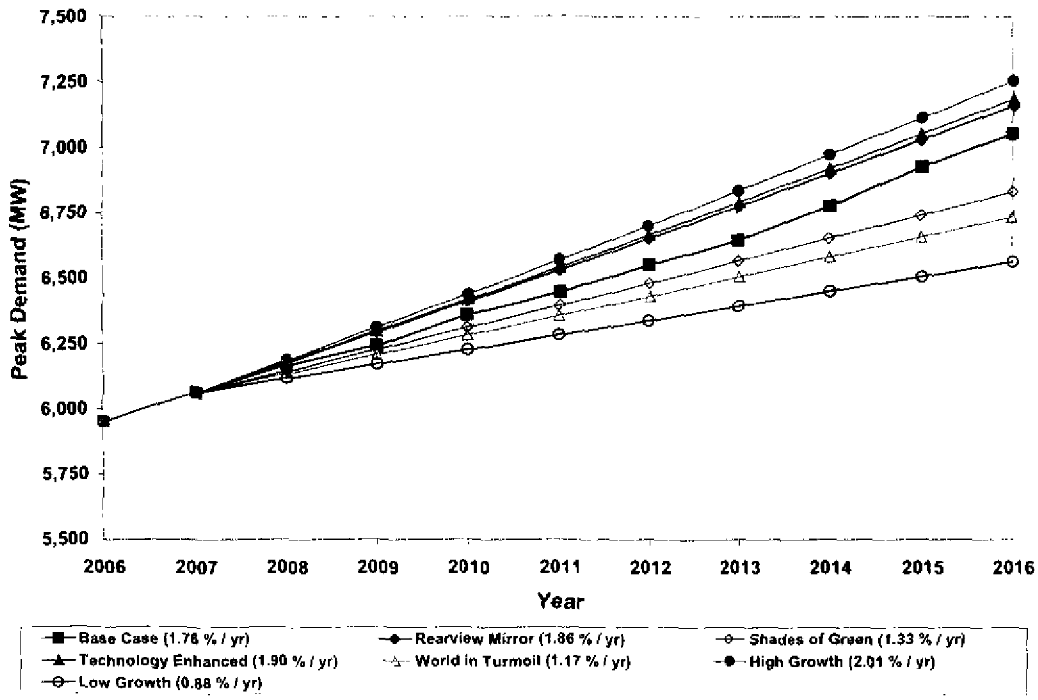


Figure IV-4 Alternative Case Peak Demand Variation (Average Growth in %/yr)

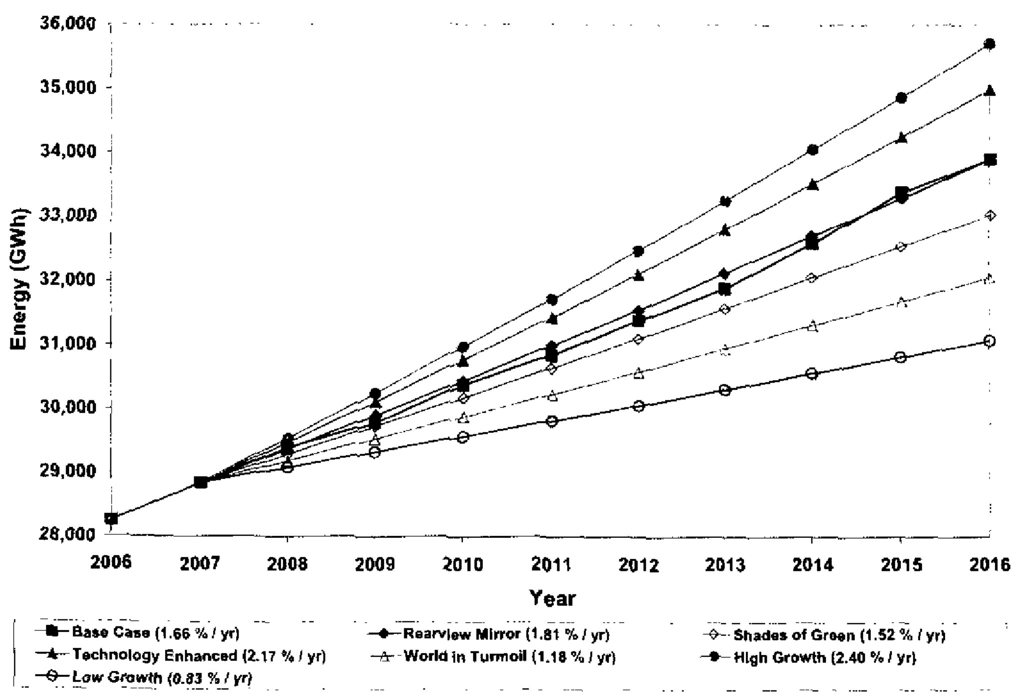


Figure IV-5 Alternative Case Energy Forecast Variation (Average Growth in %/yr)

Redacted – Highly Sensitive Confidential Information

Figure IV-6 Alternative Case Natural Gas Prices (Real 2006 $)

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Figure IV-7 Alternative Case SO_2 Emissions Costs (Real 2006 $)

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Figure IV-8 Alternate Case NO_X Emissions Costs (Real 2006 $)

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Figure IV-9 Alternate Case Hg Emissions Costs (Real 2006 $)

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Figure IV-10 Alternate Case CO_2 Emissions Costs (Real 2006 $)

It should be noted that the alternative environmental assumptions are modeled to begin in 2010.

b. Changes in the Optimal Portfolio under Alternative Cases

Table IV-9 below presents the optimal capacity expansion strategies produced by CEM for each of the 11 alternative planning cases described above and repeats the Base Case results for comparison purposes.

An examination of the alternative portfolios indicates that CEM frequently selects seven resource options, although the mix and year of selection varies in response to the different assumptions. Not surprisingly, the model chooses the low-cost Enid option for 2007 in all scenarios. Next, the model prefers the peaking options in years 2008-2010, varying the amount and timing of peaking capacity depending on the growth in peak demand. These peaking resources serve as a bridge to the first baseload option that in almost all cases is the 365 MW jointly owned supercritical coal plant with an in-service date of 2011. The cases begin to vary more significantly in the last five years of the ten-year planning horizon. In all cases, existing units were not retired or mothballed.

Thus, the cases are remarkably consistent for the first five years of the planning horizon (the years in which an action plan has been developed). Of the three cases in which the 365 MW coal plant is not selected, two are technology-constrained cases (All Gas and High Wind). The third case, Technology Enhanced, is similar to the All Gas case with lower natural gas prices. In this case, CEM selects the 500 MW combined cycle plant in 2011.

CEM selects wind and DSM when assumptions make fossil units much more expensive to operate. With respect to wind, the model is basing this preference on the energy value provided by wind as the capacity value is assumed to be relatively low (5 %). DSM also provides a hedge against higher fuel prices.

It is also worth noting that CEM selects a 900 MW subcritical coal plant in 2014 in the Base Case and in two of the alternative cases. Although there is a long lead-time to construct a baseload coal plant, this decision can be deferred at least two years and evaluated (along with other options) based on conditions at that time. The model suggests that this option will compete against large natural gas-fired CC plants and other baseload options. This consideration, as well as other factors, is reflected in the Resource Strategy that is presented in Section V.

It is also worth pointing out that there is not as much disparity of NPVRR among scenarios. This is due in large part to the fact that the costs associated with the existing 6,122 MW portfolio are reflected in each scenario.

Expansion Strategy	NPVRR ($ Million)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Base Case	**10,431**	Enid	LM6000-1 LMS100-1	LMS100-1	LMS100-1	Super PC-365	None	None	Sub PC-900	None	None
Rearview Mirror (RM)	**+ 62**	Enid	LMS100-2	LMS100-1	LMS100-1	Super PC-365	None	2x1 7FA-1	None	None	Non
Shades of Green (SG)	**+ 688**	Enid	LMS100-1 Wind-1	LMS100-1	LMS100-1 Wind-1	Super PC-365	Wind-3	Wind-3	7EA-1 Wind-3	2x1 7FA-1 Wind-3	Wind-3
Technology Enhanced (TE)	**+ 376**	Enid	LMS100-2	LMS100-1	LMS100-1 Wind-2	2x1 7FA-1	None	LM6000-1	2x1 7FA-1	None	None
World in Turmoil (WT)	**+ 151**	Enid	LMS100-1	LMS100-1	LMS100-1	LMS100-1	LMS100-1	LMS100-1	None	Sub PC-900	None
High OK/AR Growth (HG)	**+ 107**	Enid	LMS100-2	LMS100-1	LMS100-1 LM6000-1	Super PC-365	None	LMS100-1	Sub PC-900	None	None
Low OK/AR Growth (NG)	**+ 499**	Enid	LMS100-1	LMS100-1	None	Super PC-365	None	None	None	2x1 7FA-1	None
All Gas (AG)	**+ 905**	Enid	LMS100-2 Wind-4	None	LMS100-2	2x1 7FA-1	None	None	Wind-3	2x1 7FA-1 Wind-3	Wind-3
All Coal (AC)	**+ 947**	Enid	LMS100-1 LM6000-1	LMS100-1	LMS100-1	Super PC-365	None	7EA-1 LM6000-1	None	Sub PC-900	None
High DSM & Wind (HR)	**+ 746**	Enid DSM-2	Wind-8 DSM-20	DSM-8	DSM-13	Wind-1 DSM-10	DSM-11	DSM-11	DSM-15	2x1 7FA-1 DSM-6	None
High Wind (HW)	**+ 418**	Enid	LMS100-1 Wind-8	LMS100-1	LMS100-1 LM6000-1	2x1 7FA-1	Wind-1	None	LMS100-1	2x1 7FA-1	None
No Energy Market (NM)	**+ 261**	Enid	LMS100-1 LM6000-1	LMS100-1	LMS100-1	Super PC-365	None	None	Sub PC-900	None	None
Color Legend (Technology - # of units):											
Gas-Fired Combustion Turbine Units											
Gas-Fired Combined Cycle Units											
Coal-Fired Units											
Renewable (Wind/DSM) Units											
No Units Added											

Table IV-9 Capacity Expansion Strategies (10 years) – Alternative Cases

C. Analysis of Risk and the Use of PAR

Although it is a regulated utility, OG&E operates in a competitive, market-based environment, in which there is much uncertainty or risk. Broadly speaking, risks can be categorized as stochastic, scenario, or paradigm risks. The attributes of each of these risk categories is summarized in Table IV-10 below.

Risk	Feature	Analytic Approach	Example(s)
Stochastic	Statistically quantifiable	Explicitly represent in the analysis as an uncertain variable	Retail Electric Load, Fuel Prices
Scenario	Measurable but not statistically quantifiable	Represent as "sensitivity cases" and contrast to a Base Case analysis	Future environmental regulations
Paradigm	Describable but difficult to represent numerically	Address qualitatively outside the modeling process	Electric industry regulation

Table IV-10 Risk Characterization

Stochastic risks (also known as probabilistic risks) are risks for which there is enough information to allow planners to make reasonable assumptions regarding the probability that certain outcomes will result. For example, natural gas price risk can be represented as a distribution of values around the expected value. The probability distributions and associated "stochastic parameters" used in such an analysis are usually drawn from analysis of historical information, although such analysis can be tempered by expert judgment. Fuel and electricity prices, electric demand, and generating unit performance risks fall into this category and are directly captured in PAR.

Scenario risks typically have less available information; however, enough data is available to allow planners to make reasonable assumptions about potential future environments. For example, while no one knows the timing or magnitude of a potential carbon tax, enough literature is available to construct a scenario incorporating a potential carbon tax. Such risks are then represented by deterministic "scenarios" of the future (used in the CEM planning case analyses discussed above), which are then analyzed using a stochastic market analysis platform such as PAR.

Paradigm risks are those risks that are so inherently uncertain that any quantification could be considered speculative. While there is no clear dividing line between scenario risks and paradigm risks, the uncertainty regarding the eventual outcome of RTO development in SPP is a source of paradigm risk for OG&E.

This IRP relies upon both stochastic analysis and scenario analysis to capture the range of risks faced by OG&E. Stochastic analysis captures the volatility of key input assumptions for variables that are outside of OG&E's control (such as fuel prices), while scenario analysis allows for explicit treatment of identified uncertainties for which the preparation of statistical parameters would be at least somewhat subjective. As discussed below, OG&E performed stochastic risk assessments on the Base Case and on the alternative cases. OG&E believes that the combination of scenarios with uncertainty allows for not only the evaluation of risk but a deeper understanding of the possible strategy implications of uncertainty.

1. Risk Factors and Distribution Curves

OG&E developed probability distribution curves for four assumptions: (1) retail load forecast, (2) natural gas prices, (3) coal prices, and (4) emissions costs. These curves were developed around the Base Case assumptions by specifying low and high values for each year, as well as parameters that determine the shape of the curve. Each of these curves is described below.

a. Retail Load Risk

The factors affecting load are described in Section II.C. Figure IV-11 below shows the effect of both long term and short-term volatility. This figure shows the minimum, average, and maximum values of the peak demand throughout the planning period of 2007 through 2016. Figure IV-12 the probability distribution curve for the compound average growth rate in load.

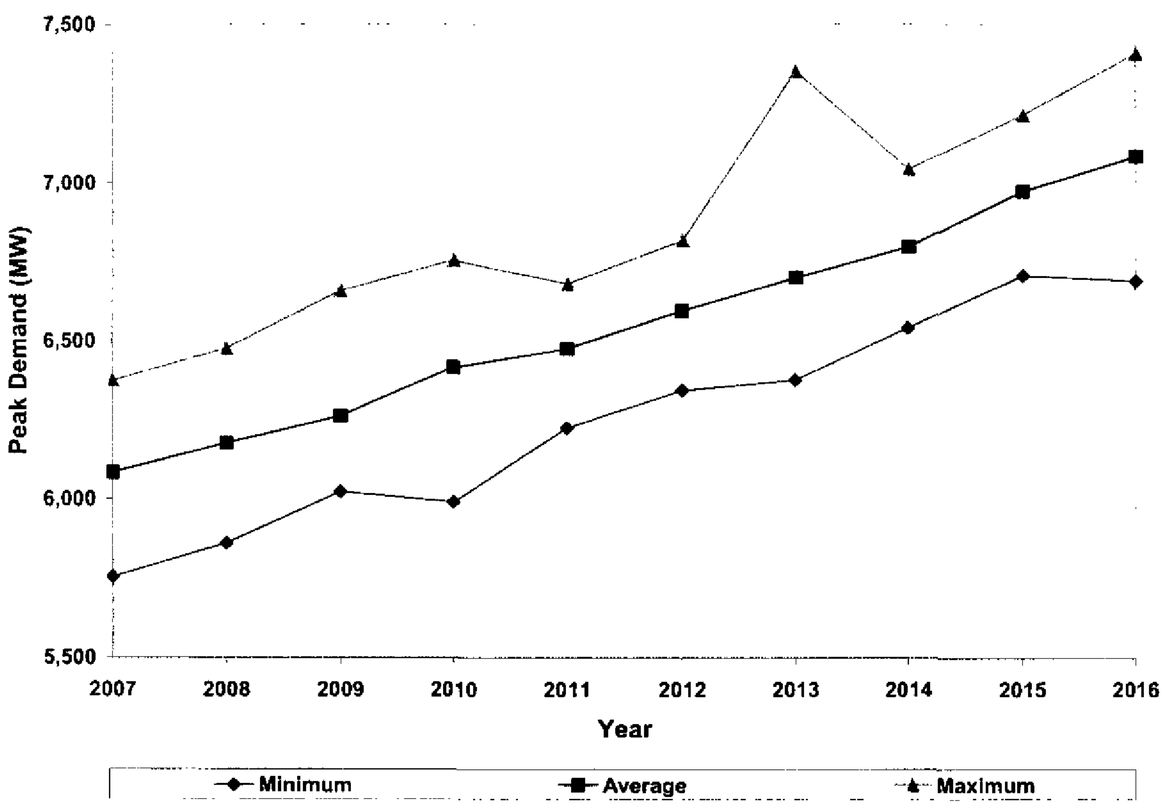

Figure IV-11 Peak Demand Stochastic Range

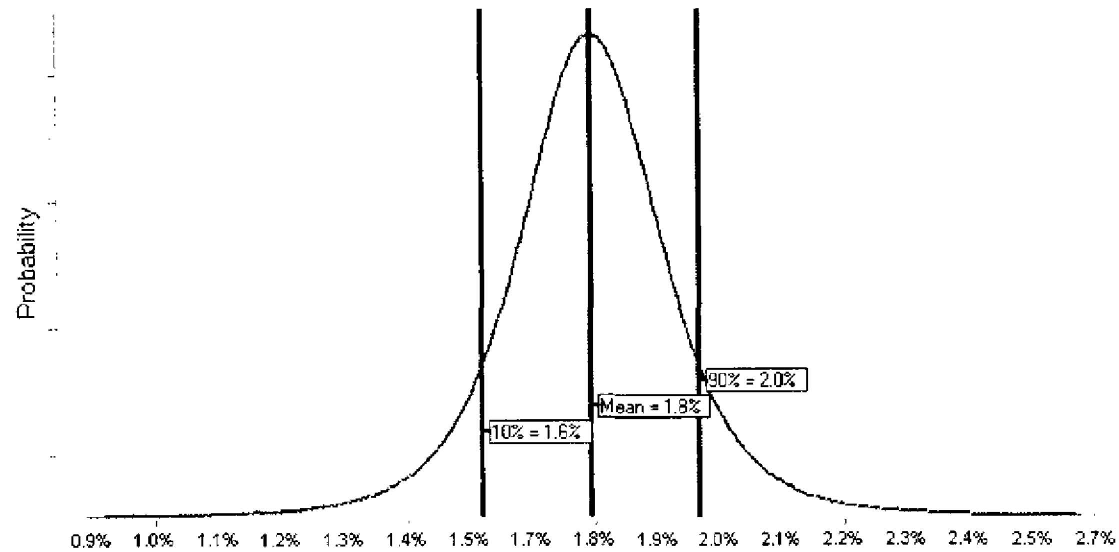

Figure IV-12 30-Year Compound Average Growth Rate in Load

b. Natural Gas Price Risk

A natural gas price forecast distribution was developed based on CERA's four scenarios modified to reflect the input of OG&E's MRC. The values range between 2 \$/MMBtu and 15 \$/MMBtu (2006 \$) as shown in Figure IV-13. This distribution is applied in all years of the model with a correlation to the previous year's value. Figure IV-14 below shows the minimum, average, and maximum values of the natural gas price throughout the planning period of 2007 through 2016.

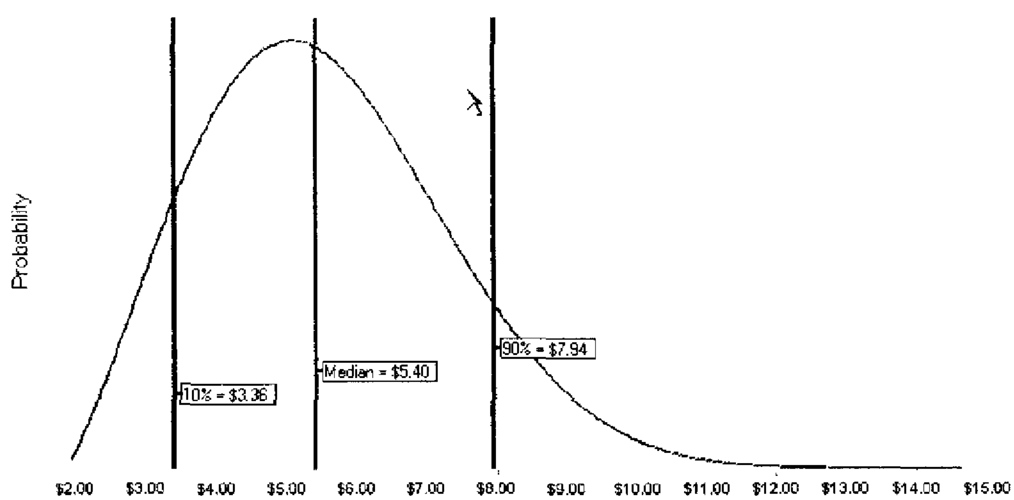

Figure IV-13 Natural Gas Price Distribution (2006 \$/MMBtu)

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Figure IV-14 Natural Gas Prices Stochastic Range

c. Coal Price Risk

A coal price distribution was developed for OG&E by L. E. Peabody & Associates, Inc. in January 2006. This forecast is shown in Figure IV-15. Figure IV-16 below shows the minimum, average, and maximum values of the coal price throughout the planning period of 2007 through 2016.

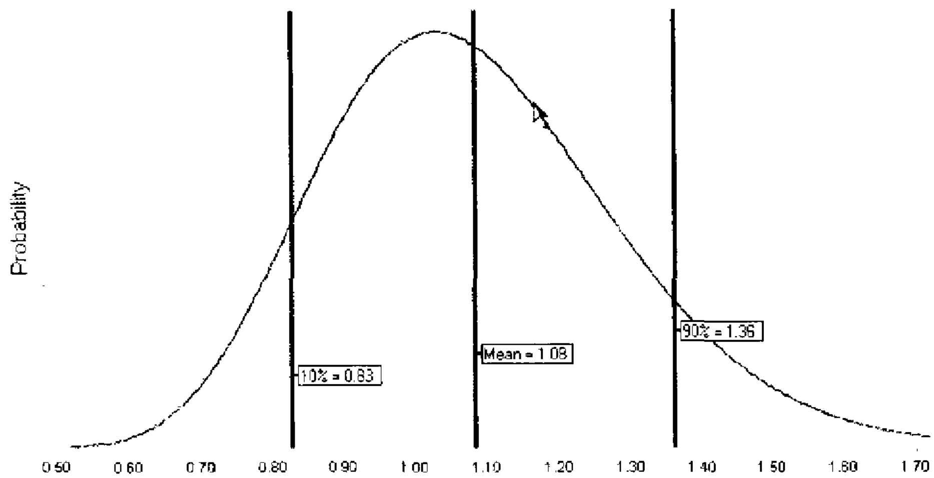

Figure IV-15 Coal Price Distribution (2006 $/MMBtu)

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Figure IV-16 Coal Prices Stochastic Range

d. Environmental Cost Risk

Environmental risk is perhaps the most difficult to model mathematically but most likely offers the greatest risk to NPVRR. These assumptions have been developed based on the CERA scenarios. Thus, each of the four CERA scenarios has estimates of the cost and timing of a possible tax for the four major pollutants: SO_2, NO_X, CO_2, and Hg.

As discussed in Section III.E.5, due to a recent ruling by the EPA, more is certain about the control or costs of SO_2 and NO_X. OG&E has assumed that they will be controlled, as they are today, in a Cap and Trade-type market. Thus, OG&E's existing units will continue to receive credits, and that the new units will meet EPA requirements. This assumption reduces the risk to the customer for increased cost for either of these pollutants.

On the other hand, little is known about the possible cost of CO_2 and Hg. For this study it is assumed they both could have a direct tax, expressed in $/ton or $/lb. To capture this risk, the highest cost from the CERA scenarios was used as the expected value if a tax is levied. The probability that a tax will be levied was also modeled. If a tax is not levied it is assumed the control will be a Cap and Trade-type control as described for SO_2 and NO_X. To model the uncertainty, the maximum estimated cost, shown below, has a 25%

chance of occurring. Figure IV-17 and Figure IV-18 below show the minimum, average, and maximum values of CO_2 costs and Hg costs, respectively, throughout the planning period of 2007 through 2016.

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Figure IV-17 CO_2 Costs Stochastic Range

Redacted – Highly Sensitive Confidential Information

Figure IV-18 Hg Costs Stochastic Range

2. Stochastic Risk Assessment Using PAR

As noted above, PAR was used to assess the distribution of NPVRR around a deterministic calculation based on the expected values for each assumption. This analysis was performed by subjecting the optimal portfolio in each scenario to probability curves for each of the four risks around the Base Case expected values. The PAR runs depict the risk of pursuing an optimal portfolio developed based on a future state that differs from the Base Case assumptions.

A distribution curve showing the cumulative probability distribution for revenue requirements is developed for each alternative scenario and then compared to the Base Case. In general, lower revenue requirements and tighter bandwidths around expected revenue requirements (e.g., lower risk) are preferred.

Risk is measured as an assessment of the revenue requirements "at risk" (RRaR) for plausible strategies and the sensitivity of strategies to key uncertainties, including the price of natural gas. Revenue requirements at risk are a comparison of the expected revenue requirement and the 90^{th} percentile value as shown in Figure IV-19. The 90^{th} percentile value is the point on the probability curve where there is a 90% certainty the revenue requirement will be less.

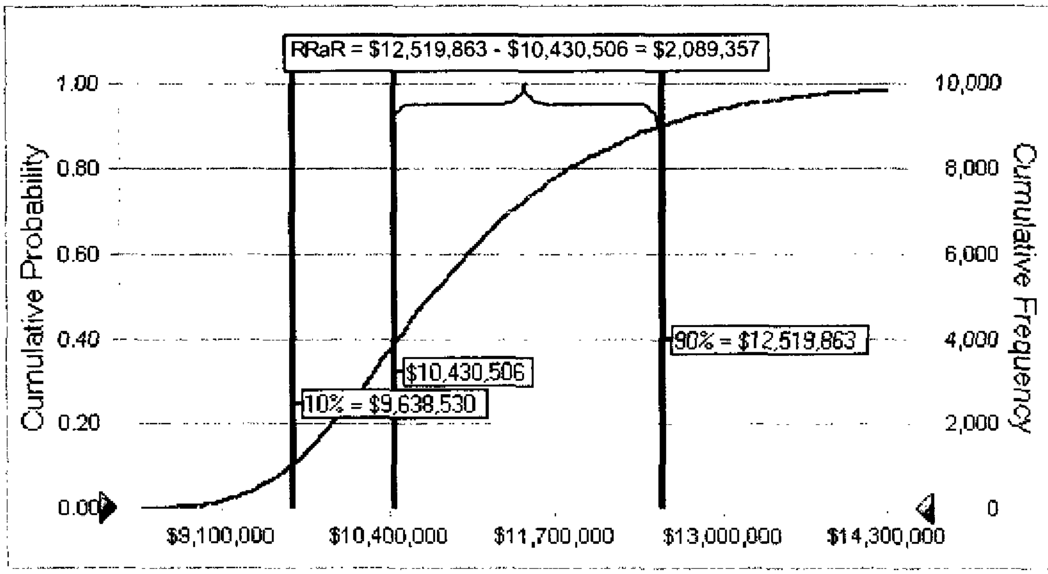


Figure IV-19 Cumulative Probability of Revenue Requirements

To summarize, the key risks accounted for in this analysis include:

- The shorter-term volatility in retail load, which is driven mainly by weather conditions;
- Uncertainty in the long term growth in the demand for electricity in OG&E's service territory, which is primarily driven by long term economic factors;
- The uncertainty in the price of power plant fuel (primarily natural gas and coal); and
- Future environmental regulations, which will impact capital and operating costs at existing facilities as well as the cost of new generation resources.

Figure IV-20 presents the NPVRR probability distribution based on the PAR runs for all cases. This figure graphically depicts the position of each curve relative to the Base Case. The probability that the Base Case optimal portfolio will have the lowest NPVRR is approximately 65%. Moreover, the alternative portfolios do not perform significantly better than the Base Case anywhere along the distribution curve.

There are two factors that contribute to these results. First, all portfolios include the existing OG&E assets and thus the NPVRR is largely driven by the operation of these assets. The four risk factors have a significant impact on the costs of the existing portfolio. Second, all portfolios are subject to risk associated with natural gas and coal prices. This second factor was examined by comparing the High Wind Case to the Base Case as shown in Figure IV-21. The Aggressive Wind Case, 80 MW of additional wind capacity each year, is located to the right of the Base Case for much of the curve. It is slightly steeper, suggesting that this strategy would reduce OG&E's exposure to higher than anticipated fossil fuel prices and possible environmental taxes. Again, the differences are not as dramatic as one might expect due to the impact of the existing portfolio in both cases.

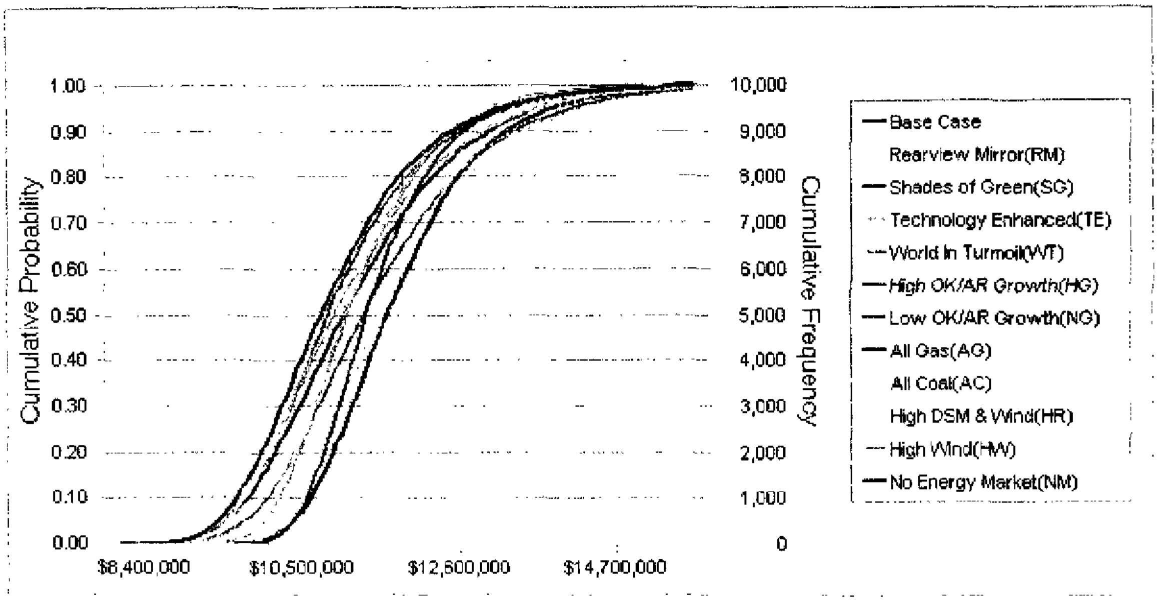


Figure IV-20 NPVRR Cumulative Probability Distribution for All Cases

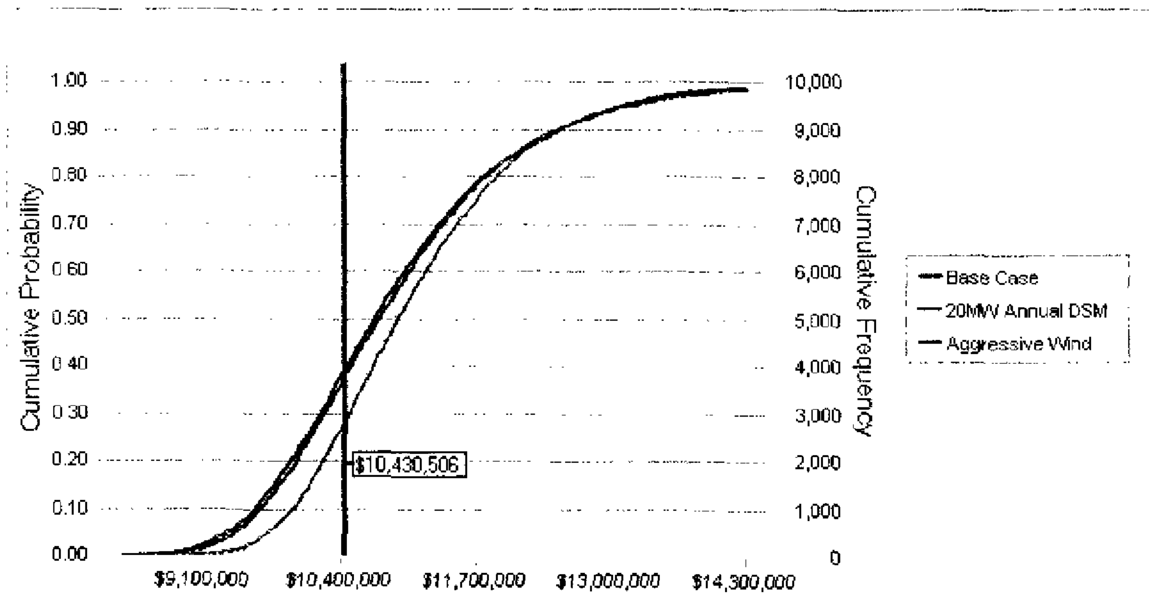


Figure IV-21 NPVRR Cumulative Probability Distribution for Base and Sensitivity Cases

It is apparent from the PAR analyses that the greatest risks result from imposition of CO_2 and mercury taxes and from rising natural gas prices.

V. Resource Strategy and Implementation Plan

A. Resource Strategy

The "Resource Strategy" and associated Five-Year Action Plan have been developed based on the Base Case results, as modified to address uncertainty and risk. The Five-Year Action Plan focuses on the first five years (2007-2011) and includes an update to the IRP in the fall of 2008.

Uncertainty and risk have been addressed in four ways, resulting in modifications to the Base Case optimal portfolio.

First, as there is a considerable uncertainty in the short-term load forecast, OG&E believes that a more robust, flexible approach is preferable. The Resource Strategy reflects PPA contracts based on an RFP to be issued this fall. As there is great value in flexibility with respect to quality, quantity and term, the RFP will seek to determine if this flexibility can be acquired on reasonable terms.

Second, OG&E is conducting a study to develop a greater understanding of the potential for DSM as an incremental resource. This study will be completed in 2007. If DSM proves to be a viable and meaningful source of incremental capacity, OG&E will determine if modifications to its DSM tariff are appropriate.

Third, wind power also provides a hedge against higher fuel prices. Thus, OG&E will continue to pursue opportunities to acquire or develop incremental wind generation.

Finally, OG&E will file an updated IRP in the fall of 2008, and depending on the findings at that time currently anticipates, at this time, that OG&E will issue an RFP for baseload capacity in 2009. A self-build option would compete against third-party options in this RFP.

Table V-1 below presents the optimal portfolios for both the Base Case as well as the Five-Year Action Plan.

Year	Minimum Incremental Capacity Need (MW)	Modeling Results (Preferred Resource)	Five-Year Action Plan
2007	46	48 MW Enid Plant	• Repair and Upgrade Enid • RFP for Economy Energy for 2007 • Complete DSM Study • Review Existing Contracts

Year	Minimum Incremental Capacity Need (MW)	Modeling Results (Preferred Resource)	Five-Year Action Plan
2008	120	100 MW Peaker; 45 MW Peaker	• Results of RFP for Capacity and/or Energy for 2008 - 2010 • Update IRP • Review Existing Contracts
2009	90	100 MW Peaker	• Results of RFP for Capacity and/or Energy for 2008 – 2010 • Review Existing Contracts
2010	130	100 MW Peaker	• Results of RFP for Capacity and/or Energy for 2008 – 2010 • Issue RFP for Capacity and/or Energy for Future Years • Review Existing Contracts
2011	90	400 MW Joint Coal Baseload Unit	• Commercial Operation of 400 MW Coal Plant • Results of 2010 RFP • Review Existing Contracts

Table V-1 Five-Year Action Plan

Although not specified in this table, wind generation will continue to be pursued throughout the 10-year planning horizon.

B. Implementation Plan

Given that the Resource Strategy is based on the results of the Base Case, the Five-Year Action Plan to implement the Resource Strategy is as follows:

- 2006 (Fall): Submit RFP's for peaking needs; one for the summer of 2007, and one for the 2008-2010 timeframe;
- 2006 (Fall): Pursue regulatory approval and begin permitting process for new Red Rock Generating Facility (joint OG&E / PSO / OMPA 950 MW supercritical pulverized coal unit);
- 2007 (Spring): Evaluation of 2006 Peaking RFP bids, negotiations, and execution of contract(s);
- 2007 (Spring): Repair and upgrade Enid CTs;
- 2007: Complete DSM Study;
- 2008 (Fall): Update IRP;
- 2008 (Fall): Submit RFP for 2014 baseload capacity needs, with self-build option;
- 2009 (Spring): Evaluation of 2008 Baseload RFP bids, negotiations, and execution of contract(s); and
- 2011: Complete construction of Red Rock Generating Facility.

Appendix A – Fuel Procurement / Risk Management Plan

This appendix contains OG&E's *Fuel Supply Portfolio and Risk Management Plan* as filed with the OCC on May 15, 2006.

BEFORE THE
CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF ERNEST G. JOHNSON, DIRECTOR OF THE PUBLIC UTILITY DIVISION, OKLAHOMA CORPORATION COMMISSION, TO REQUIRE OKLAHOMA GAS AND ELECTRIC COMPANY TO INFORM THE COMMISSION REGARDING PLANNING OF ENERGY PROCUREMENT PRACTICES AND RISK MANAGEMENT STRATEGIES AND FOR A DETERMINATION AS TO APPROPRIATE METHODS TO LESSEN THE IMPACT OF ENERGY PRICE VOLATILITY UPON CONSUMERS	) CAUSE NO. PUD 200100095

OKLAHOMA GAS AND ELECTRIC COMPANY

Fuel Supply Portfolio and Risk Management Plan

May 15, 2006

OG&E

OKLAHOMA GAS AND ELECTRIC COMPANY

Fuel Supply Portfolio and Risk Management Plan

INDEX

Part A. 2006 Fuel Procurement Plan Report

I. Introduction 1

A. Planning Objectives 2

B. Waiver Language 2

C. Prior Procurement Plan Feedback 2

II. Load/Demand Forecasting 3

III. Resources and Capabilities 4

IV. Comparison Between Alternatives 4

A. Methodology Discussion 4

B. Relevant Scenarios 9

C. Gas Volatility/Cost Benefit Analysis 10

V. Selected Resource Plan 12

VI. Energy Outlook for 2006 12

A. Forecasted 2006 Energy Costs 12

B. OG&E Compared to National Averages 13

C. OG&E Compared to Regional Averages 13

VII. Conclusion 14

Part B. Energy Procurement Practices and Risk Management Strategies

I. Historical Overview 16

II. Fuel Supply Portfolio 16

III. Fuel Planning Process 17

IV. Resource Procurement Practices 17

- A. Coal 17
- B. Natural Gas 17
- C. Fuel Oil 18
- D. Purchased Power 18

V. Customer Programs and Education 19

- A. Current Programs 19

VI. Risk Management Strategies 21

Part A. 2006 FUEL PROCUREMENT PLAN REPORT

I. Introduction

Oklahoma Gas and Electric ("OG&E" or "Company") is a vertically integrated, Investor Owned, Electric Utility. The Company serves approximately 740,600[1] retail customers in two states (Oklahoma and Arkansas). In addition to these retail customers, OG&E provides wholesale electric service under FERC jurisdiction. Both retail and wholesale customers are considered native load.

The electricity sold to native load customers comes from several sources. These sources include:

- Company owned coal and gas generation facilities;
- Economic power purchases;
- Purchases from qualifying facilities under PURPA;
- Purchase of renewable resource energy (Wind);

In addition to these resources, the Company actively manages several demand-side management (DSM) programs. DSM resources do not generate energy for consumers. The Company manages its generation resources and DSM through planning and operations to meet customer load responsibility on a total system basis.

As is reflected in this report, during 2005 OG&E used competitive procurement all natural gas, oil, purchased power, and a significant portion of its coal requirements. The remainder of OG&E's fuel and fuel-related services are provided under long-term contracts, some of which were obtained through competitive bidding. As these long term contracts expire, OG&E will evaluate, on a case by case basis, the use of the new procurement rules approved by this Commission in January of 2006.

[1] This number excludes Security Lighting Accounts. Total Retail is approximately 809,100 accounts.

A. Planning Objectives

OG&E is committed to its obligation to serve its customers at a high level of satisfaction. As such, OG&E plans for its fuel and purchased power needs with the following primary objectives in mind:

1. **Reliability** – OG&E's goal is to ensure an adequate supply of fossil fuels, dependable transportation and sufficient inventories.
2. **Lowest Reasonable Cost** – Minimize the system cost of electricity by optimizing the portfolio of available resources.
3. **Stable Electric Rates** – Maintain diversity of fuel, purchase power contracts and generating assets to mitigate the impact of changing fuel prices.

B. Waiver Language

Any forecasts included in this report are provided with the best information available at the date of this report and are subject to change without notice as new information becomes available.

C. Prior Procurement Plan Feedback

In the 2005 fuel procurement plan, OG&E forecasted a total gas burn of 70,869,513 MMBtu. Actual MMBtu burn was 72,796,058 MMBtu. The variance of 2.72% over planned was due primarily to the partial coal supply disruption caused by emergency repairs to the Union Pacific/Burlington Northern Santa Fe track referred to as the Joint Line in the Southern Powder River basin. Actual base load gas supply for 2005 was 58,338,000 MMBtu. The 2005 projected peak load responsibility was 5,820 MW compared to the actual peak load responsibility of 5,766 MW (less than 1%). With respect to energy sales, the 2005 plan projected 27,500,000 MWH system energy for 2005 compared to the actual energy of 28,100,000 MWH (a 2% increase). The primary reason for this difference was that cooling degree days were 10% higher than normal in the summer of 2005.

II. Load/Demand Forecasting

OG&E performs an annual review and forecast of its total energy requirement and peak demand. This information provides the foundation of fuel planning for the following year. In addition, it provides information for management to identify trends. Figure 1 details the forecast completed in the first quarter of 2006 for OG&E's system load responsibility and energy sales.

Figure 1.

OG&E Projected Resources, Demand & Energy			
Description (MW)	2006	2007	2008
Existing Capacity (Note 1)	6,090	6,121	6,121
- Committed Retirements	0	0	0
OG&E Total Owned Capacity (Note 2)	6,090	6,121	6,121
Capacity Purchases			
PowerSmith Cogen	120	120	120
Applied Energy Systems (AES)	320	320	320
Mid - Continent Power Co. (MCPC)	110	110	110
+ Total Cogeneration Contracts (Note 3)	550	550	550
+ SPA Allocation	31	31	31
Total Capacity Resources	6,671	6,702	6,702
Capacity Margin	846	764	660
Capacity Margin (w/o additional capacity)	12.70%	11.40%	9.80%
+ Additional Capacity Needs (Note 4)	0	50	170
Total Net Dependable Capability	**6,671**	**6,752**	**6,872**
Capacity Margin	846	814	830
Capacity Margin (w/ additional capacity)	12.70%	12.10%	12.10%
OG&E System Load Responsibility	5,952	6,065	6,169
- Total Interruptible Demand (Note 5)	127	127	127
Net On System Demand	**5,825**	**5,938**	**6,042**
System Energy (GWH/Y)	**28.3**	**28.8**	**28.1**

Notes:

1. Includes Wind Capacity of: 3 MW (2006); and 9 MW (2007 and 2008).
2. Increases in existing operational capacity reflect 2006 and 2007 system coal efficiency enhancements.

3. Existing cogeneration contracts: AES-320 MW; MCPC-110 MW; PowerSmith-120 MW.
4. Capacity needed to meet SPP minimum 12% capacity margin (rounded to nearest 10 MW).
5. Demonstrated megawatts associated with Demand Side Management Programs are assumed to be constant throughout the planning period.

III. Resources and Capabilities

OG&E has a mix of gas and coal fired generating units along with 550 MW of firm purchased power contracts and 50 MW of non-dispatchable wind generated energy. In addition, the Company has proposed a new project for 120 MW per hour of non-dispatchable wind generated energy (see PUD 200500059 and 200500177). The Company expects the Centennial wind farm to be in commercial operation prior to December 31, 2006. During each summer, OG&E completes an assessment of its generation fleet's peak load capabilities. This assessment includes full load capability tests that are done in accordance with the Southwest Power Pool Guidelines. Figure 1 reflects the results of the assessment completed at the end of the summer of 2005 along with projected unit capabilities for the next three years.

IV. Comparison between Alternatives

In planning its fuel supply for generation, OG&E must include available capacity and a mix of fuel and purchased power to meet the projected energy needs of customers. However, because a substantial portion of OG&E's generation costs are at or below the production costs of available purchased power, the Company focuses on alternatives involving incremental gas generation.

A. Methodology Discussion

The Company must insure that sufficient capacity is available to meet its forecasted peak demand. Once capacity from all resources is sufficient, OG&E then models the resources to provide the most favorably priced energy as described in the resource dispatch order below. This resource dispatch order reflects OG&E's commitment to insure reliability and maximize the use of its lowest cost generation resources. System constraints such as must run units and contract commitments must be taken into account.

Typical Resource Dispatch Order

1) Must Run Units and Contract Commitments
    - Units for reliability and ancillary services
    - Wind (when available)
    - Conoco
    - SPA (Southwest Power Administration)
    - AES (up to 65% capacity factor)
    - PowerSmith (up to 50% of annual hours)
2) OG&E Coal Units
3) AES – Above contractual minimum (priced just above OG&E coal units)
4) McClain
5) PowerSmith – Above contractual minimum
6) OG&E Gas-steam or economy purchased power
7) MCPC (Mid-Continent Power Co.) or OG&E Gas Turbines

Charts 1 and 2 illustrate a typical summer and spring day dispatch of resources.

Chart 1 illustrates a typical summer day dispatch of OG&E's generation resources

CHART 1

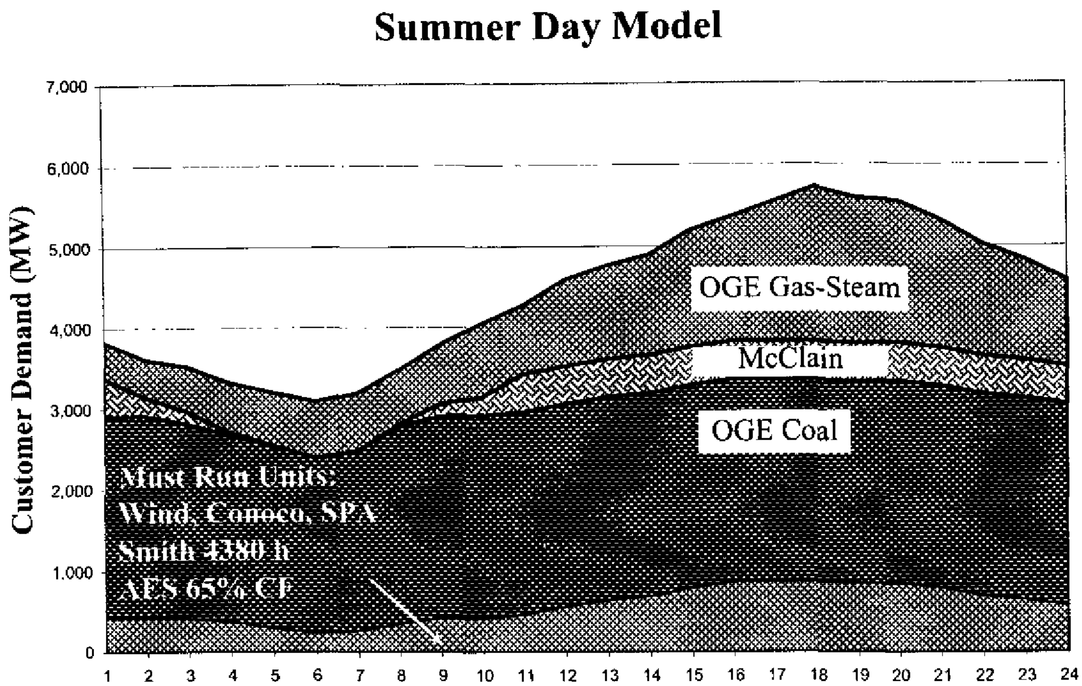
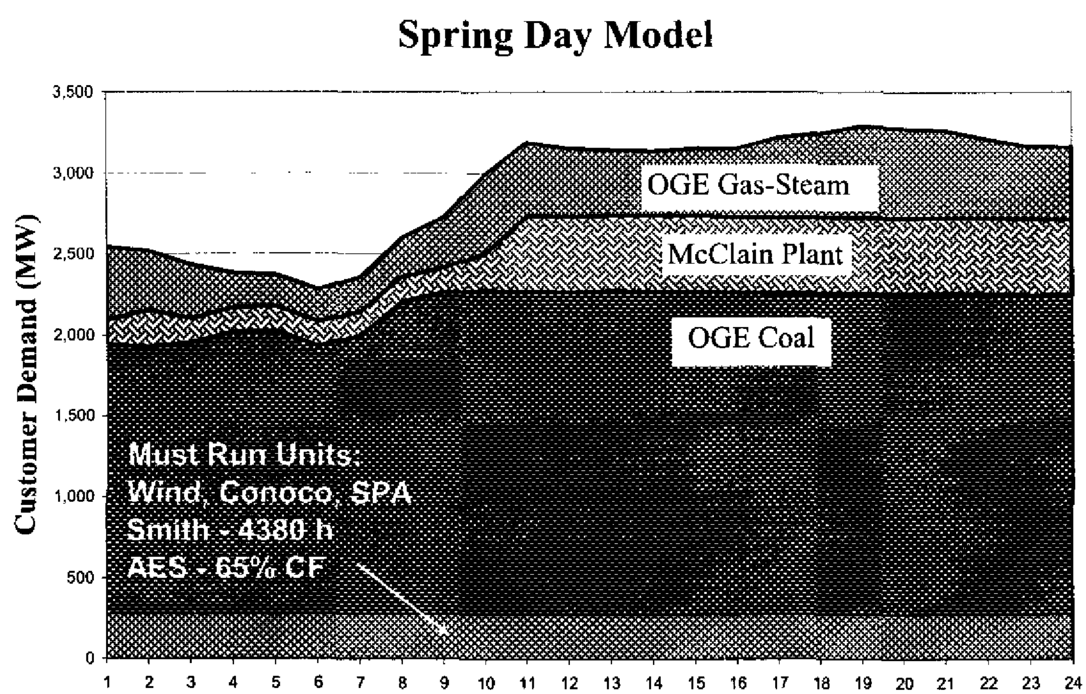


Chart 2 illustrates a typical spring day dispatch of OG&E's generation resources.

CHART 2



No fuel is required for energy produced by wind. OG&E does not procure fuel for AES, PowerSmith, MCPC, SPA or purchase power providers.

Coal purchases are scheduled based on projected burns and inventory requirements. Coal is procured generally under long-term contracts, a significant portion of which is procured through competitive bidding. Currently, coal is purchased from all four (4) producers located in the Southern Powder River Basin of Wyoming. Rail transportation is under long-term contracts. Gas transportation and storage service are under long-term contracts at this time. As these long term contracts expire, OG&E will evaluate, on a case by case basis, the use of the new procurement rules approved by this Commission in January of 2006.

The Company competitively bids for all of its natural gas requirements. The three major types of natural gas supply contracts are:

- Base Load Gas (long term contracts)
- Monthly Gas
- Daily Gas

OG&E does not procure all of its gas requirements under long-term contracts due to the uncertainty of load, the weather effect on load, availability of lower cost generation units, purchase power opportunities, and status of fuel inventories.

The decision to purchase base load gas, if any, is generally made early in the year. In February 2006, OG&E issued a Request for Proposals (RFP) to a diverse set of gas providers. OG&E received bids from the following nine (9) Companies:

1. BP Energy Company
2. ChevronTexaco Natural Gas
3. Cimmarex Energy Co
4. Walden Energy
5. Conoco/Phillips Company
6. Eagle Energy Partners I, LP
7. Shell Trading
8. OGE Energy Resources
9. Tenaska Marketing Ventures

Seven of theses bidders were eventually awarded monthly contracts. None of these bidders received more than 41% of any month's total award. Figure 2 is a list of the seven 7 suppliers currently providing gas and their average annual percentage of base load gas. These contracts amount to 30% of the Company's anticipated 2006 annual natural gas requirements. In total, the Company acquired 67.3% of its anticipated 2006 annual gas burn through the RFPs including the March 2006 RFP. OG&E expects uncertainty caused by the future SPP Energy Imbalance Services marketplace will reduce the amount of term gas purchases.

Figure 2

	Vendor	
1	Tenaska	40.6%
2	OGE ER	20.2%
3	Conoco	16.1%
4	Chevron/Texaco	2.7%
5	Walden	2.7%
6	Eagle	13.5%
7	BP	4.2%
	TOTAL	100.0%

The decision to procure monthly gas is generally made prior to the last week of the month preceding delivery. The decisions are based on many factors. These factors include, but are not limited to, anticipated availability and price of purchased power relative to OG&E's incremental gas generation cost, future gas price outlook, low cost generation unit availability, status of inventory, the availability of gas supply, weather forecast, and expected load.

The decision to procure daily gas is generally made early the day prior to delivery. This decision is based on many of the same factors as discussed above.

B. Relevant Scenarios

As previously discussed, because a substantial portion of OG&E's generation costs are at or below the production costs of available purchased power, the Company focuses on alternatives involving incremental gas generation. Ideally, the Company would develop scenarios for two broad areas: 1) incremental gas generation versus purchased power; and 2) the relationship between the three major types of natural gas supply contracts. However, the absence of a liquid purchased power market available to the OG&E service area has prevented the Company from performing any meaningful volatility analysis regarding incremental gas and purchased power.

The Company anticipated its Electronic Bulletin Board[2] (EBB), would create a more transparent process to purchase next day, non firm economy energy. Although the EBB has created transparency, it has not produced a meaningful number of economy transactions to date. During the eight months of operation in 2005, OG&E received less than 80 offers through the EBB affecting less than 50 days. Each offer was analyzed to determine savings our customers. Only five (5) of the offers resulted in savings and were accepted.

[2] The Electronic Bulletin Board became operational in April of 2005.

The Company examined scenarios which analyzed the volatility of procurement strategies involving the three major types of natural gas supply contracts. The three scenarios are:

1. Purchase all of the Company's gas needs on the spot market using a daily purchase program
2. Purchase all of the Company's gas needs on a base load basis
3. Purchase most of the Company's gas needs on a base load basis (RFP) and the remainder on a daily basis (the current gas procurement process)

C. Gas Volatility / Cost Benefit Analysis

Figure 3 describes the results of the analysis conducted on the 3 scenarios. For purposes of this analysis, volatility is defined as the statistical measure of a risk profile. It is a percentage calculated by dividing the standard deviation of price by its simple average.

Figure 3

		12 Months Ending December 2005	
	Scenario	$ / MMBtu	Volatility
1	Purchase All Gas on the Spot Market at Daily Trade Price	$7.3820	32.96%
2	Purchase All Gas at Monthly-Term Prices	$7.4154	23.51%
3	Purchase Term Gas Under RFB Limit Day Gas to under 75,000 MMBtu / Day Utilize Storage Capability	$7.9348	24.71%

Scenario 1, purchasing 100% of OG&E's gas requirements on the spot market, creates operational risks for the Company that were not analyzed. In the summer, OG&E burns about 320,000 MMBtu on an average day and can easily burn as much as 480,000 MMBtu gas on a hot day to meet its peak load responsibility. These high volumes of gas are not available on a daily basis. With hot summer weather and air conditioning load, the driving factors behind these high volume needs, other electric companies as well as gas storage operators are competing with OG&E in the market to procure their needs. For example, the volatility in the gas commodity market for 2005 was 32.96%. Since the summer 2005 weather was 10% warmer than normal[3], the 32.96% market volatility was quite wild compared with the 2004 commodity market volatility of 10.33%. In addition, volatility values do not reflect the risk that the required gas supply volumes are not available in quantities needed in the daily spot market.

The analysis of Scenario 2 produced the lowest market volatility quotient (23.51%). Purchasing 100% of OG&E's gas requirements on a base load basis produces a different set of difficulties. All are demand related and driven by weather. Hotter than normal weather (cooling degree days) means the Company may not have enough gas under contract requiring swing gas purchases at a time when other companies would also be entering the market. These conditions were present in 2005. The risks associated with this scenario depend on the season and how many other companies are purchasing gas. Milder than normal weather could mean the Company would either: over utilize its storage capabilities; resell back to the market (a forced sale); or back down on coal generation to burn the excess gas supply. If sufficient storage were available, the Company would avoid or mitigate some of this risk. However, the Company could still experience risks from either selling gas during a depressed market or displacing coal. In February 2006, coal generation cost was $11.55 per MWh while gas generation cost was $61.50 per MWh. In other words, gas generation costs OG&E about 5 1/2 times as much as coal generation. This dramatic difference in generation costs depicts why OG&E strives to maximize its coal capacity and AES to minimize total fuel

[3] Source: National Weather Service Forecast Office F6 data for Oklahoma City. Normal CDD is 2129, Actual 2005 CDD was 2351 CDD.

supply cost. Even with the current level of gas storage, dependence on base load gas creates an unacceptable risk to the Company's coal capacity factor.

Scenario 3 is the Company's selected plan which is consistent with the overall goal to maximize coal generation. This plan allows the Company to operate within the constraints of the gas supply market in this region. The analysis produced a volatility quotient of 24.71%. This is very close to the volatility produced by scenario 2 (which is predicated on the Company having perfect knowledge of the gas market each day of the year). Also, this level of volatility on the gas side, combined with the company's coal assets produced stable electric rates as shown in Attachment 4.

V. Selected Resource Plan

In 2005, the Company's generation portfolio approach allowed OG&E to produce nearly 61% of its customer's energy needs from its low cost coal generating units even though the installed coal capacity was only 41% of its total generation capability. When AES's energy is added, this percentage increased to nearly 70%. In 2006, the Company's selected resource plan is to again maximize coal and other low cost resources. In addition, the Company will continue to seek favorably priced purchased power opportunities as compared to incremental gas generation not used for reliability and ancillary services. This strategy will be achieved utilizing the EBB and other offers to the Company during the year and the upcoming SPP Energy Imbalance Services market scheduled to commence on October 1, 2006. For its gas requirements, OG&E is procuring gas consistent with the concepts demonstrated in scenario 3.

On July 22, 2005, OG&E revised Part B, section IV.B. of the 2005 Plan to describe the company's intention to: review the expected impact on gas transportation and storage needs of the SPP Energy Imbalance Market ("SPP Market"), which at that time was scheduled for implementation on May 1, 2006; and consider options for including entities other than Enogex in the provisioning of integrated, no-notice, load following gas transportation and storage service to OG&E's generating facilities. OG&E indicated that, based on the results of those reviews, the company anticipated initiating competitive bids for transportation and storage services to those generation facilities served by Enogex, to be effective no later than the summer of 2007.

Certain requirements of the SPP Energy Imbalance Market will not be known until FERC issues final approval of the SPP Market proposal; and, consequently, the planned May 1, 2006 implementation of the SPP Market has been delayed until October 1, 2006. If the SPP Market proposal is substantially approved by FERC, OG&E has concluded that the integrated, no-notice, load following service currently utilized by OG&E will be an advantage in the SPP Market. OG&E is currently exploring options to expand the number of transportation pipelines and/or storage facilities which could contribute to maintaining the current service, including use of a header system approach. Based on FERC's expected finalization of SPP Market requirements on or before October 1, 2006 and information known to OG&E at this time, the company expects to initiate a competitive bid process in the fourth quarter of 2006 for service to be delivered in late 2007.

OG&E burned 72,796,058 MMBtu of gas in 2005. The Company projects a total gas burn of 74,915,211 MMBtu in 2006. Including gas procured in March 2006, OG&E now has a base load quantity of 50,400,000 MMBtu (67.3% of the projected 2006 gas burn) through an RFP process. The remaining gas requirements for 2006 (daily and monthly) will also be procured through a competitive bid process, and the volumes are dependent upon factors discussed in Part III. A. above.

VI. Energy Outlook

A. Forecasted Energy Costs

The Company has provided the Commission a forward looking energy outlook for its Residential and all Commercial customers (GS-1,PL-1,LPL-1) annually. For 2006, the forward looking energy outlook is included in this plan and is presented in Figure 4. Figure 4 reflects the expected monthly costs to customers for the summer and winter seasons. See Attachment 2 for additional detail.

Figure 4 – 2006 Energy Outlook

	Residential[3]		Commercial[4]	
	Winter	Summer	Winter	Summer
KWh =	1,070	1,450	1,760	2,300
Customer Charge	$6.50	$6.50	$12.00	$12.00
Fuel[1]	$49.67	$67.31	$81.70	$106.76
Other[2]	$37.84	$75.62	$80.96	$167.58
Total	$94.01	$149.43	$174.66	$286.34

1. Includes: Fuel adjustment clause plus fuel rebased in tariffs
2. Includes: Non-fuel portion of tariff, APUAF, CCR, and MBTC
3. Residential averages are based on a winter period use of 1,070 kWh per month and a summer period use of 1,450 kWh per month.
4. Commercial averages are based on a winter period use of 1,760 kWh per month and a summer period use of 2,300 kWh per month.

B. OG&E Compared to National Averages

OG&E continues to compare favorably against national averages. For the residential class, OG&E's rates average 18.9% lower than the national average. The commercial class averages 15.8% lower than the national average and the rates for industrial class averages 10.0% less than the national average.[4]

[4] EEI Typical Bills and Average Rates Report - winter 2006, and OG&E FERC Form I. Customer bills from OG&E were slightly less than reported by EEI because of the smoothing components in OG&E's FCA tariff.

C. OG&E Compared to Regional Averages

OG&E continues to compare favorably against regional averages. For the residential class, OG&E's rates average 9.8% lower than the regional average. The commercial class averages 6.0% lower than the regional average and the rates for industrial class averages 13.7% less than the regional average.[5]

VII. Conclusion

OG&E is committed to its obligation to serve its Oklahoma customers at a very high level of customer satisfaction. To meet this obligation, OG&E performs an annual review and forecast of its total energy requirement and peak demand. This information provides the foundation of fuel planning for the following year.

OG&E has a mix of coal and gas generating units along with 550 MW of firm purchased power contracts and 50 MW of non dispatchable wind generated energy. OG&E has proposed an additional 120 MW per hour of non dispatchable wind from the Centennial wind farm project. This proposal is currently under review by this Commission. In 2006, the Company's selected resource plan is to again maximize coal and other low cost resources. In addition, the Company will continue to seek favorably priced purchased power opportunities as compared to incremental gas generation not used for reliability and ancillary services. For the Summer of 2006, OG&E has entered into an agreement with Red Bud for 440 MW of firm energy for the months of June, July and August. After October 1, 2006, OG&E will participate in the SPP Energy Imbalance Market. This is expected to enhance the Company's ability to access economy purchase opportunities. During each summer, OG&E completes an assessment of its generation fleet's peak load capabilities. This assessment

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[5] Id.

includes full load capability tests that are done in accordance with the Southwest Power Pool Guidelines. The Company ensures that sufficient capacity is available to meet its forecasted peak demand. OG&E then plans to provide energy as described in the resource dispatch order as explained in Part IV.A. above.

Coal purchases are scheduled in accordance with this plan based on projected burns and inventory requirements. Coal is procured generally under long-term contracts. The Company competitively bids for procurement of natural gas, oil and purchase power. Any bids for long term supply will be done in accordance with the new OCC procurement rules.

Because a substantial portion of OG&E's generation costs are at or below the production costs of available purchased power, the Company focuses on alternatives involving incremental gas generation. The Company examined scenarios which analyzed the volatility of procurement strategies using three scenarios based on the major types of natural gas supply contracts. Those scenarios are described in Part IV. above. The volatility analysis concluded that Scenario 3 was an appropriate course of action as having nearly the lowest percentage of volatility. Scenario 3 involves purchasing a significant portion of the Company's Base gas burn requirement through an RFP process and maximizing the utilization of the Company's contracted storage capacity.

In 2005, the Company's generation portfolio approach allowed OG&E to produce nearly 70% of its energy delivered to customers using coal-burning resources. In 2006, OG&E's selected strategy is to maximize coal and other low cost resources again.

OG&E is providing the Commission with a forward looking energy outlook for its customers in this plan (see Part A.VI.A.) and is providing the Commission with a comparison of OG&E's Oklahoma retail rates with national and regional averages. As will be seen from those comparisons presented in Part A.VI.B, OG&E's Oklahoma retail rates continue to compare quite favorably for nearly all classes of service on both national and regional basis.

Part B: OG&E ENERGY PROCUREMENT PRACTICES AND RISK MANAGEMENT STRATEGIES

I. Historical Overview

Oklahoma Gas and Electric Company's ("OG&E" or "Company") Fuel Supply Portfolio and Risk Management Plan is filed in accordance with Order No. 454609 ("the Order") issued on July 25, 2001 in Cause No. PUD 200100095. Commission Order No. 454609 set forth certain policy guidelines for review of fuel procurement practices and risk management strategies. The Commission's policy guidelines are listed on Attachment 1. OG&E has provided its Fuel Supply Portfolio and Risk Management Plan for each year subsequent to the effective date of the Order.

OG&E's Fuel Supply Portfolio is discussed in Section B.II. and a breakdown by resource type is illustrated in Attachment 3. The Company's existing and proposed Risk Management Strategies are discussed in Section B.VI.

II. Fuel Supply Portfolio

OG&E's Fuel Supply Portfolio consists of Company-owned electric generation facilities fueled by coal, gas & fuel oil, plus purchased capacity from cogeneration contracts, purchased power contracts, and the wholesale market. The Company currently owns 6,090 MW of operational generation capacity. The generation capacity is approximately 41% coal-fired and 59% natural gas-fired. The fuel cost to produce electricity from OG&E's coal generation is significantly less expensive compared to gas-fired generation. OG&E's primary fuel management strategy is to maximize the utilization of its coal generation capacity.

III. 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, price forecasts, contract commitments and obligations, and a forecast of future gas prices. 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 utilizing all the above information and forecasts. This plan provides the Company with an estimate of annual usage by fuel type. The annual projection incorporates OG&E's forecasted gas burn requirements for the next year that is then broken down into monthly requirements.

IV. Resource Procurement Practices

A. Coal

Coal is procured generally under long-term contracts. Adjustments are made quarterly to the price of coal (up or down) due to quality variations. Currently, coal is purchased from all four (4) producers located in the Southern Powder River Basin of Wyoming. Rail transportation is under long-term contracts with fixed rates per ton per year.

B. Natural Gas

OG&E obtains less than 0.1% of its gas requirements from older contracts with fixed prices. The Company acquired 67.3% of its anticipated 2006 annual gas burn through the RFPs including the March 2006 RFP. Gas transportation and storage services are under long-term contract.

C. Fuel Oil

Fuel oil is purchased through a bidding process and the price includes delivery to the plant. Fuel oil is primarily used for startup fuel at the Sooner coal-fired plant. In addition, some of OG&E's gas plants maintain alternate fuel capability that could be utilized during times of gas shortage and periods when gas prices rise to very high levels if inventory were available.

D. Purchased Power

Cogeneration Contracts

The energy purchased through the AES Shady Point, Inc. cogeneration contract is priced slightly above OG&E's coal cost and is included in the portfolio of units to be dispatched. The energy from the remaining cogeneration contracts is purchased based on gas costs.

Renewable Resources

OG&E is committed to providing access to low cost renewable resources to our customers. OG&E has one Wind Energy Purchase Agreement through which the Company purchases wind energy from FPLE Sooner Wind, LLC. OG&E customers have responded favorably to the Company's optional wind tariff offering, and the production from the FPLE Sooner Wind farm is currently fully subscribed. In addition, OG&E has executed an Engineering, Procurement and Construction Contract with Invenergy Wind Development Oklahoma LLC, to construct an additional 120 MW of non dispatchable wind from the Centennial wind farm project. This proposal has been approved by this Commission. Based on customer participation, OG&E's Wind Energy program ranks among the top ten wind energy programs nationally.

Economy Purchased Power

OG&E regularly seeks and welcomes non-firm economy purchases on an hourly basis when the purchase will reduce costs to customers. These non-firm economy purchases are attractive because there are: no contracts; no capacity payments; and no firm transmission expense. Several factors are considered when OG&E decides to enter into economy purchases. First, the purchase must not interfere with reliable system operations. Second, the purchase must fit in the portfolio with other resources, system operations and customer load requirements on a "real-time" basis.

Electronic Bulletin Board (EBB)

In 2005, the Company initiated its new electronic bulletin board. This innovative web-based program allows qualified power providers to submit day-ahead offers to the Company's operations dispatch and fuels department for sales of economical power. The Company provides an hourly estimated purchase profile on the web page. Each bidder may provide a bid for any hourly period for comparison with OG&E's incremental gas generation costs. Submission of offers is allowed each weekday until 0600 hours (prior to day of sale). All offers are analyzed and if accepted are awarded by 0830 hours allowing both parties to procure or adjust gas purchases. The Electronic Bulletin Board continues in operation today.

V. CUSTOMER PROGRAMS AND EDUCATION

A. CURRENT PROGRAMS

OG&E currently provides options designed to allow customers more flexibility in dealing with their energy costs. The following discussion provides a brief summary of these options.

The **Average Monthly Payment (AMP)** plan offers residential customers the option of "smoothing" their monthly billing. The plan lowers typically high-cost summer bills by averaging the summer time-frame bills with lower spring/fall/winter bills. The AMP plan reduces the volatility of a customer's bill from month to month.

The **Guaranteed Flat Bill (GFB) program** is an optional tariff for Residential and Small General Service customers. This program is similar in function to OG&E's AMP plan program with one very noticeable exception -- the bill will not change for 12 months and there is no subsequent dollar "true-up" at the end of the 12-month period.

The optional **Levelized Demand Tariffs (PL-LEV, LPL-LEV)** are offered to meet specific industrial and commercial customer needs. These tariffs are offered to help customers levelize their own internal cash flows. These targeted customers should have high load factors and consistent monthly demands to benefit from the programs.

Real Time Pricing (RTP) is the ultimate "price-response" program. Hourly prices are provided to participants for each hour of the year. Low prices in non-peak hours signal customers to use more of the Company's product. High prices during peak summer periods signal the participants to cut back on consumption. This reduced consumption is beneficial to both participants and other customers on the OG&E system.

Curtailment programs (CR-1 and IR-1) are demand response programs which have existed at OG&E since mid-1980. A little more than 100 MW of generation or purchased power are avoided every year due to curtailment.

The **PACE Rider** offers voluntary curtailment options to an additional 1,500 customers during load-shedding events. New software allows wide-spread notification and coordination with a greater number of curtailment customers.

The combination of PACE and existing curtailment programs could produce over 200 MW of load curtailment. This rider is offered as an alternative to mandatory load curtailment options.

Time-Of-Use (TOU) tariffs encourage customers to shift usage to off peak periods. TOU tariffs have existed since the 1980's. Oklahoma customers currently incorporate these tariffs into their day-to-day operational practices. All OG&E customers benefit because load growth that would have occurred on OG&E's system peak is mitigated by the participant TOU customers' daily management of their load.

Compressed Time-Of-Use (TOU) tariffs provide Public Schools encouragement to shift usage to off peak periods. Compressed TOU tariffs are designed a smaller on peak periods that are assigned higher costs compared to the on peak periods for the Company's standard time-of-use tariffs. All OG&E customers benefit because load growth that would have occurred on OG&E's system peak is mitigated by the participant TOU customers' daily management of their load.

Green Power Wind Rider (GPWR) was implemented in the last quarter of 2003. Customers have the option of purchasing wind energy under this tariff when wind resource energy is available.

VI. Risk Management Strategies

The most volatile component of OG&E's Fuel Supply Portfolio is the price of natural gas. Attachment 4 illustrates how OG&E's customers have been insulated from high volatility of gas prices through a combination of maximizing coal and lower cost generation and the structure of the Company's Fuel Cost Adjustment tariff. In order to manage the risk of gas price volatility, OG&E has purchased base quantities of gas on an annual basis based on monthly gas prices. In addition, from some of this gas, OG&E has obtained the right to lock in a price for future month(s). OG&E does not engage in financial hedging because the costs related to financial hedges are not recoverable under Oklahoma statutes.

Attachment 1

POLICY GUIDELINES

1. The Commission finds that OG&E should take such steps as are reasonable and prudent to develop an appropriate diversified fuel supply portfolio plan and risk management plan which is in the best interests of its ratepayers.

2. The Commission finds that OG&E shall periodically update and annually file its fuel supply portfolio plan and risk management plan with the Staff, no later than May 15th of each year. The reasonableness and prudency of OG&E's contracting and hedging decisions shall be reviewed pursuant to the Commission's Electric Rules, OAC 165:35 and applicable statutory and constitutional provisions of Oklahoma law.

3. The Commission finds that OG&E shall maintain complete records for any hedging programs it elects to utilize.

4. The Commission finds that OG&E should engage in appropriate customer education efforts to inform as many of its customers as practical regarding upcoming seasonal prices including information related to levelized billing or average payment plans or other customer programs.

5. The Commission finds that OG&E shall continue to keep the Staff closely informed of procurement options available and decisions it makes to mitigate the volatility of energy prices to its ratepayers and shall continue to participate in collaborative discussions regarding appropriate documentation to be provided to the Commission.

6. The Commission finds that OG&E is encouraged to seriously consider all the various energy supply procurement practices available to it and to carefully weigh the potential costs and benefits of each before utilizing a particular practice.

7. The Commission finds that for the purpose of allowing further inquiry regarding the hedging plans of electric utilities, further investigation of the appropriateness of financial hedging to mitigate energy price volatility should be undertaken through a Notice of Inquiry, using the information gained in this proceeding as a starting point for discussions among all interested parties.

Source: Cause NO. PUD 200100095 (Order NO. 454609); section III. Findings of Fact and Conclusions of Law.

OG&E's 2006 Energy Outlook

OG&E

OG&E		
Summer	Res.	Comm.
2003	$126.85	$260.79
2004	$121.90	$252.95
2005	$115.63	$242.19
2006	$149.43	$286.34
Winter	Res.	Comm.
2003-2004	$77.83	$153.90
2004-2005	$74.90	$149.09
2005-2006	$70.27	$140.87
2006-2007 *	$94.01	$174.66

*Winter 2006 – 2007 calculations are based on current tariff designs as approved by Commission Order 516261 (PUD 2005000151)

OG&E's 2006 Energy Outlook

OG&E

RESIDENTIAL CUSTOMER

WINTER BILLING					
Customer Charge	1	x	$ 6.50	=	$ 6.50
Energy Charge (Without Fuel)					
First 600 kWh	600	x	$ 0.0562	=	$33.72
Over 600 kWh	470	x	$ 0.0187	=	$ 8.79
APUAF	1	x	$ 0.13	=	$ 0.13
CCR	1,070	x	$(0.004523)	=	$ (4.84)
MBTC	1,070	x	$ 0.000041	=	$ 0.04
Fuel Charge	1,070	x	$ 0.046418	=	$49.67
Total Billing (Without Taxes)					**$94.01**
SUMMER BILLING					
Customer Charge	1	x	$ 6.50	=	$ 6.50
Energy Charge (Without Fuel)					
First 1,400 kWh	1,400	x	$ 0.0565	=	$79.10
Over 1,400 kWh	50	x	$ 0.0578	=	$ 2.89
APUAF	1	x	$ 0.13	=	$ 0.13
CCR	1,450	x	$(0.004523)	=	$ (6.56)
MBTC	1,450	x	$ 0.000041	=	$ 0.06
Fuel Charge	1,450	x	$ 0.046418	=	$67.31
Total Billing (Without Taxes)					**149.43**

OG&E's 2006 Energy Outlook

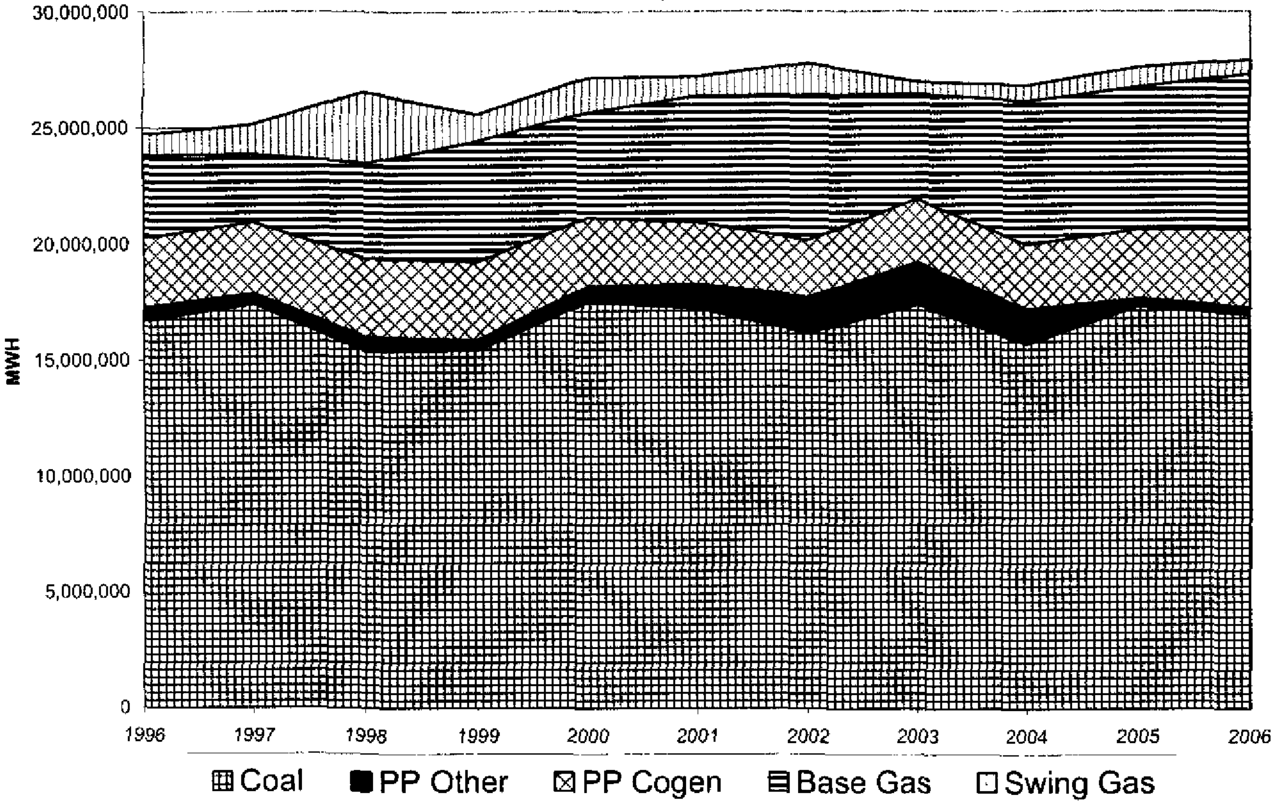
OG&E

COMMERCIAL CUSTOMER

WINTER BILLING						
Customer Charge	1	x	$ 12.00	=	$	12.00
Energy Charge (Without Fuel)						
First 1,000 kWh	1,000	x	$ 0.0675	=	$	67.50
Over 1,000 kWh	760	x	$ 0.0291	=	$	22.12
APUAF	1	x	$ 0.13	=	$	0.13
CCR	1,760	x	$(0.005033)	=	$	(8.86)
MBTC	1,760	x	$ 0.000041	=	$	0.07
Fuel Charge	1,760	x	$ 0.046418	=	$	81.70
Total Billing (Without Taxes)					**$**	**174.66**
SUMMER BILLING						
Customer Charge	1	x	$ 12.00	=	$	12.00
Energy Charge (Without Fuel)						
All kWh	2,300	x	$ 0.0778	=	$	178.94
APUAF	1	x	$ 0.13	=	$	0.13
CCR	2,300	x	$(0.005033)	=	$	(11.58)
MBTC	2,300	x	$ 0.000041	=	$	0.09
Fuel Charge	2,300	x	$ 0.046418	=	$	106.76
Total Billing (Without Taxes)					**$**	**286.34**

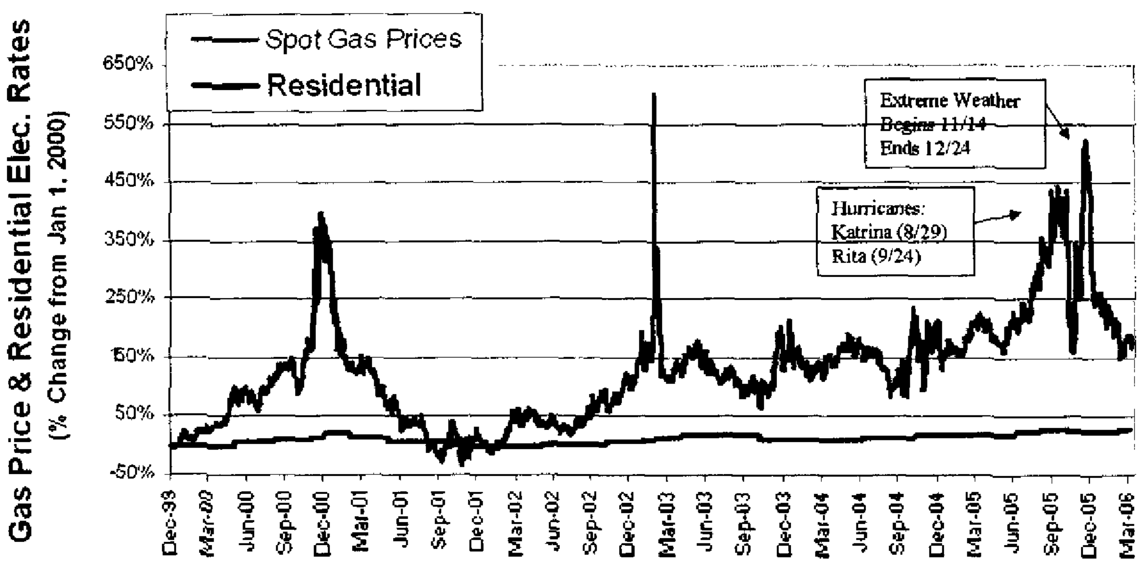
Attachment 3

Fuel Mix by Source



Note: 2006 reflects projected values.

Daily Gas Price Volatility Compared with Residential Rate Volatility



Note: 1. Fuel Adjustment Factors moved to coincide with operations month
2. *Six (6) Pipe Index*

Appendix B – 2005 Load Forecast

This appendix contains the *OG&E 2005 Load Forecast* as completed on August 30, 2005.

Final Report

OG&E 2005 Load Forecast

Prepared for:
OG&E Electric Services
Regulatory Strategies & Utility Resources

August 30, 2005

Prepared by:
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Table of Contents

Executive Summary **1**
2005 Energy Sales Forecast 1
2005 Load Responsibility Peak Demand Forecast 3
Forecast Uncertainty 3

Economic Outlook **8**
U.S. National Forecast 8
State of Oklahoma Forecast 8
Oklahoma City Metropolitan Area 9
State of Arkansas Forecast 9
Economic Drivers for Energy Forecast 10

Load Responsibility Peak Demand Forecasting Model **11**
Peak Demand Forecasting Methodology 11
Forecasting Peak Loads 12
Expected Loads by Weather Probability 13
FERC Adjustments 15
Economic Uncertainty 17

Retail Energy Models **18**
Econometric Modeling Process 18
2005 Energy Forecast 19
FERC Adjustments 20
Energy Forecast Uncertainty 23

Retail Customer Forecasting Models **25**
Retail Customer Econometric Modeling Process and Forecast 25

Data Sources **27**
Internal Company Information 27
Information Obtained from External Sources 28

Executive Summary

This report presents Oklahoma Gas & Electric Services' (OG&E) 2005 load forecasts. It describes both the peak demand and energy forecasting models developed by OG&E's Regulatory Strategies & Utility Resources Department and Quantec, LLC, with input from OG&E's interdepartmental Forecasting Task Force.

The 2005 retail sales forecast utilized the revenue class-based econometric modeling framework that has been in place since 1997. The 2005 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 FERC energy sales and demand forecast includes wholesale contracts as post-modeling adjustments.

2005 Energy Sales Forecast

The 2005 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 derived from the following:

- The Oklahoma Economic Outlook, prepared by the Oklahoma State University (OSU) College of Business Administration, Department of Economics and Legal Studies
- The Arkansas Economic Outlook, prepared by the University of Arkansas Little Rock (UALR) Institute for Economic Advancement

Underlying Economic Fundamentals

Following the 2001-2002 recession and slow recovery in 2003, acceleration of the economy in 2004 and underlying fundamentals in OG&E's service territory should bring OG&E's retail energy sales back to long-term post-recession trends. The following excerpts from OSU's November 2004 Outlook and June 2005 Outlook Update summarize the current situation.

> The state economy accelerated rapidly in the fourth quarter of 2004 and is currently on pace to slightly exceed our initial 2005 forecast. The state economy is thriving in the current environment of low interest rates and inflation, resurging demand for workers in most industries, continued strong productivity growth, and a booming housing market.
>
> At the national level, forecasts for real Gross Domestic Product suggest that the national economy has slowed markedly in the past two quarters and is now making a slow transition to a new intermediate-term real growth rate of 3 percent. Various measures of state economic activity confirm that state growth is closely tracking national conditions and likely peaked in the past 3-6 months as well. State employment growth surged to a 2.8 percent annual rate in the first quarter of 2005 as the state added 10,000 new jobs in the period. Personal income

growth increased at a 7.1 pace the past four quarters and reached an annual rate of 13.3 percent in the fourth quarter of 2004. The pace of job formation and income growth the past two quarters is not sustainable and suggests that the state will slow slightly to a more moderate pace through the remainder of this year.

The latest personal income release suggests that the state is maintaining recent income gains relative to the nation. State per capita personal income relative to the nation has jumped from 82 percent to 86 percent since 2000. Based on the data, however, the gains have been enjoyed mostly by the rural areas and the Oklahoma City metro area. Oklahoma City per capita income has increased from 89 percent of the national level to a forecasted 94 percent in 2005.[1]

Energy Sales Forecast

The final energy forecast, which is summarized in Table 1 below, adds FERC wholesale sales contracts and line losses to retail econometric mode forecast projections. The forecast (and actual 2004 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 2.0% over the next decade.

Table 1: 2005 Energy Sales Forecast

Year	Energy Forecast (MWh)*	Energy Growth Rates
2004	26,847,686	
2005	27,546,765	2.60%
2006	28,245,496	2.54%
2007	28,839,705	2.10%
2008	29,385,767	1.89%
2009	29,772,912	1.32%
2010	30,373,873	2.02%
2011	30,835,384	1.52%
2012	31,380,059	1.77%
2013	31,880,670	1.60%
2014	32,581,645	2.20%
2015	33,378,233	2.44%

* Includes FERC sales and line losses

1 OSU Economic outlook found at: http://economy.okstate.edu/outlook.

2005 Load Responsibility Peak Demand Forecast

The 2005 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 week days 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 relationship 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 2 shows the actual 2004 load, along with the final load responsibility forecast for 2005 and beyond. The forecast is based on average weather conditions over the past 32 years. Underlying retail peak loads are anticipated to grow at an average annual rate of 1.8% over the next decade, which is slightly less than the growth rate for retail energy sales.

Table 2: 2005 Load Responsibility Peak Demand Forecast

Year	Load Responsibility Peak Demand (MW) Forecast* *(Average Weather)*	Growth Rates
2004	5,689	
2005	5,820	2.31%
2006	5,952	2.26%
2007	6,065	1.91%
2008	6,169	1.72%
2009	6,243	1.20%
2010	6,358	1.83%
2011	6,445	1.38%
2012	6,549	1.60%
2013	6,643	1.45%
2014	6,776	1.99%
2015	6,926	2.21%

* Includes FERC loads and line losses

Forecast Uncertainty

OG&E's energy and peak demand modeling approaches directly address the uncertainty associated with both the economy and weather. Economic uncertainty is represented through development of "high" and "low" scenarios, based on alternate assumptions of economic activity over the next decade.

Weather uncertainty is represented through a Monte Carlo modeling approach where the last 32 years of actual weather are systematically input into the energy and peak models to produce a possible outcome distribution.

Economic Uncertainty

The economic series' developed by Global Insight, OSU, and UALR, represent "point" forecast estimates because these organizations do not provide alternate scenarios or probability statements.

Further discussions with OSU's macroeconomists centered on Oklahoma's upper economic growth potential and how present growth trends compare. OSU believes that the state's late 1990s growth represents the best achievable. Because the expected energy forecast growth rate is already approaching late 1990s levels, the high scenario reflects a growth "premium" that is only 20% higher each year than the expected case, with an average retail growth rate of 2.4% over the planning horizon. The low retail scenario incorporates a 40% reduction in the annual growth rate, yielding an average retail growth rate of 1.2%. While one could use alternate growth rates for the high and low cases, our intention here is to demonstrate the resulting, compounding impact of economic uncertainty on OG&E's sales over the next decade.

The final set of energy sales forecast scenarios are shown in Figure 1. All three energy sales scenarios contain the FERC wholesale contract adjustment previously described, and include line losses. Finally, load responsibility peak demand forecast scenarios, which are constructed in the same manner as the energy forecast scenarios, are shown in Figure 2.

Figure 1: 2005 Energy Forecast Economic Scenarios

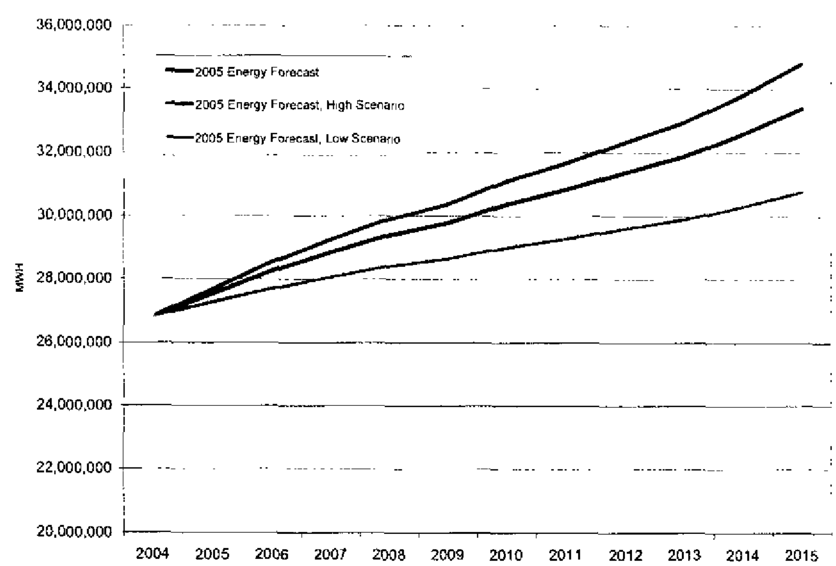
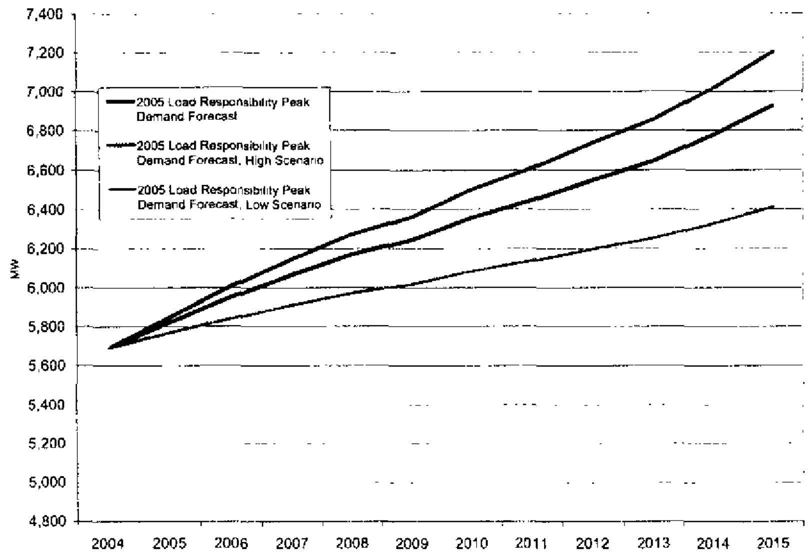


Figure 2: 2005 Load Responsibility Peak Demand Economic Scenarios



Weather Uncertainty

As is well known within 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.

OG&E's weather-year Monte Carlo approach runs weather years 1973 to 2004 through weather sensitive energy models, along with the peak demand model, to develop a probability distribution of possible outcomes. Figure 3 shows the 95% confidence interval around the expected energy sales forecast, including FERC adjustments, resulting from this modeling process.

Table 11: Energy Forecast Accounting for Changes in Wholesale Load

Energy (MWH)	2004 (Actual, Weather Adjusted)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
FERC Sales (without losses)												
MUNICIPAL	38,361	39,849	40,307	40,628	40,950	41,271	41,592	41,913	42,235	42,556	42,877	43,199
COOPERATIVE	950,727	998,741	990,279	1,023,980	1,057,682	1,091,385	1,125,087	1,158,789	1,192,491	1,226,193	1,259,895	1,293,597
SPA	132,379	139,620	140,497	142,094	143,690	145,286	146,883	148,479	150,076	151,672	153,269	154,865
OMPA PSA	211,411	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000
MEAM & Jonesboro	83,743	61,320	61,320	61,320	61,320	61,320	61,320	61,320	61,320	61,320	61,320	61,320
Total FERC Sales	1,416,621	1,458,530	1,451,402	1,487,022	1,522,642	1,558,262	1,593,882	1,629,502	1,665,122	1,700,741	1,736,361	1,771,981
Growth Rate in FERC sales		2.96%	-0.49%	2.45%	2.40%	2.34%	2.29%	2.23%	2.19%	2.14%	2.09%	2.05%
Retail Sales (without losses)												
Residential	8,178,490	8,321,017	8,499,547	8,663,958	8,856,681	8,967,207	9,143,476	9,251,728	9,394,205	9,487,867	9,660,533	9,852,114
Commercial	5,858,917	6,014,571	6,172,381	6,315,732	6,467,869	6,577,308	6,711,335	6,823,628	6,945,380	7,044,606	7,192,762	7,357,983
Industrial	4,464,041	4,622,978	4,780,407	4,930,228	5,082,313	5,214,019	5,341,840	5,467,434	5,599,961	5,722,170	5,875,487	6,049,575
Industrial Petroleum	2,477,944	2,542,862	2,637,410	2,619,495	2,509,649	2,406,062	2,404,262	2,369,582	2,351,667	2,379,307	2,413,031	2,470,091
Total Industrial	6,941,984	7,165,839	7,417,816	7,549,723	7,591,962	7,620,081	7,746,102	7,837,016	7,951,627	8,101,476	8,288,518	8,519,666
Public Authority and Street Lighting	2,766,537	2,857,793	2,931,478	3,013,103	3,102,172	3,181,312	3,272,615	3,358,081	3,454,107	3,544,941	3,658,434	3,781,453
Total Retail Sales	23,745,929	24,359,220	25,021,222	25,542,515	26,018,683	26,345,908	26,873,528	27,270,452	27,745,319	28,178,890	28,800,248	29,511,216
Growth Rate in Retail Sales		2.58%	2.72%	2.08%	1.86%	1.26%	2.00%	1.48%	1.74%	1.56%	2.21%	2.47%
Total MWH Sales (with losses)												
Total Retail Sales + FERC	25,162,550	25,817,751	26,472,624	27,029,537	27,541,325	27,904,170	28,467,410	28,899,954	29,410,441	29,879,631	30,536,609	31,283,198
Losses (.0718)	1,685,136	1,729,015	1,772,872	1,810,168	1,844,443	1,868,742	1,906,462	1,935,430	1,969,617	2,001,039	2,045,037	2,095,036
Total Retail Sales + FERC, Losses Added	**26,847,686**	**27,546,765**	**28,245,496**	**28,839,705**	**29,385,767**	**29,772,912**	**30,373,873**	**30,835,384**	**31,380,059**	**31,880,670**	**32,581,645**	**33,378,233**
Growth Rate in Total Sales		2.60%	2.54%	2.10%	1.89%	1.32%	2.02%	1.52%	1.77%	1.60%	2.20%	2.44%

Energy Forecast Uncertainty

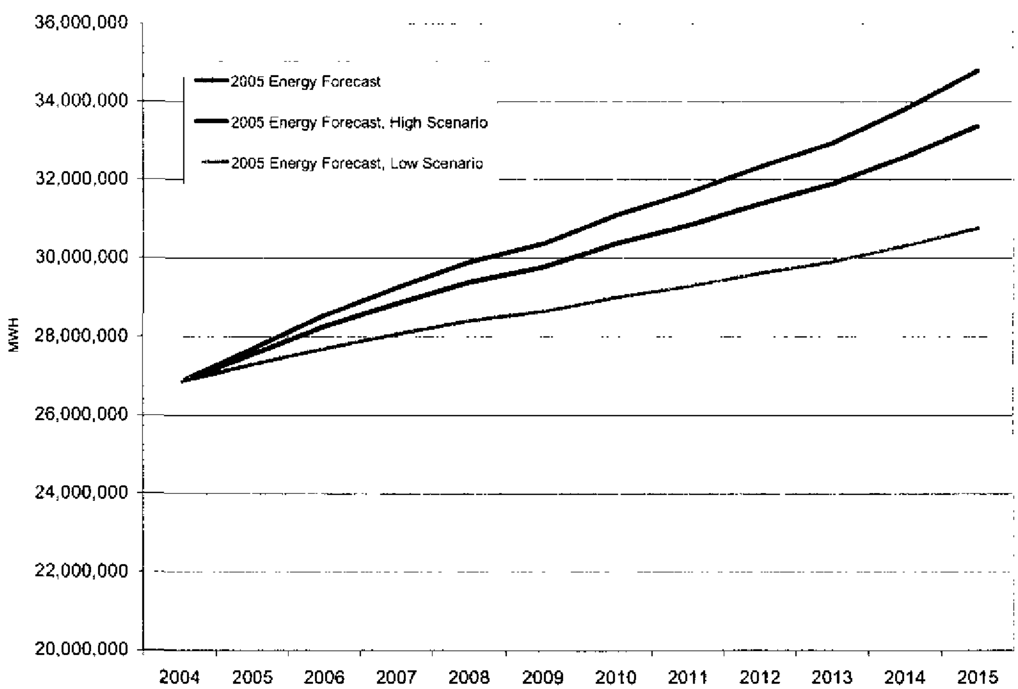
Economic Uncertainty

The economic series developed by Global Insight, OSU, and UALR represent "point" forecast estimates because these organizations do not provide alternate scenarios or probability statements.

Further discussions with OSU's macroeconomists centered around the upper growth limit potential for the Oklahoma economy and how present growth trends compared. OSU believes that state growth in the late 1990s represents the best the state could achieve. As the expected energy forecast growth rate is already approaching late 1990s levels, the high scenario reflects a growth "premium" that is only 20% higher each year than the expected case, with an average retail growth rate of 2.4% over the planning horizon. The low retail scenario incorporates a 40% reduction in the annual growth rate yielding an average retail growth rate of 1.2%. While one could use alternate growth rates for the high and low cases, our intention here is to demonstrate the resulting, compounding impact of economic uncertainty on OG&E's sales over the next decade.

The final set of energy sales forecast scenarios are shown in Figure 7. All three energy sales scenarios contain the FERC wholesale contract adjustment previously described, and include line losses.

Figure 7: 2005 Energy Forecast Economic Scenarios

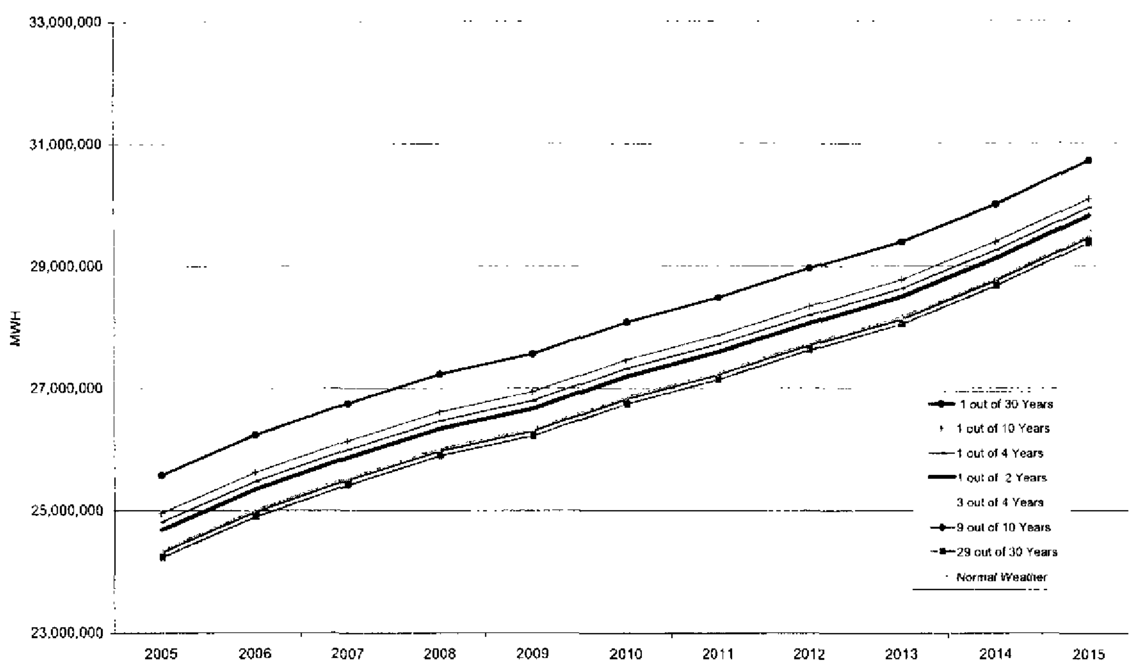


Weather Uncertainty

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 input 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 1973 to 2004 through the weather sensitive energy models and the peak demand model to develop a probability distribution of possible outcomes. Figure 8 shows the results directly from this modeling process for energy sales and excludes FERC adjustments.

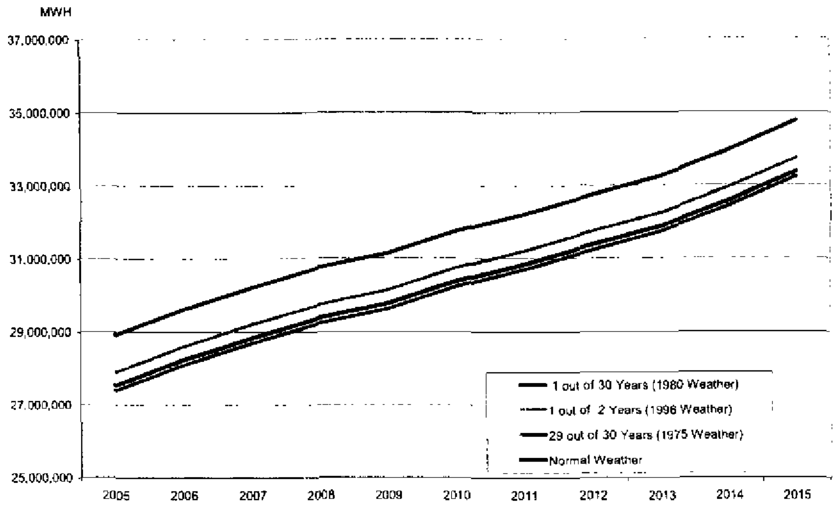
Figure 8: Retail Energy Model Forecast Outcomes by Weather Probability



The results interpretation follows. The "1 out of 2" years forecast line shows the retail energy sales, assuming the average of the weather years over the 32-year period. The 1-out-of-2 years average weather line indicates that there is a 50% probability that retail energy sales will reach this level or higher. The normal weather forecast is actually near the lower end of the distribution, which is approximately 1.3% (370,000 MWh) below the 50% probability line.

Now, consider the 1-out-of-10-years forecast. This line, which is over 1,000,000 MWh higher than the normal weather forecast, shows energy sales under more extreme weather events occurring just 10% of the time. Put differently, over a 10-year planning horizon, it is likely that OG&E's retail sales will reach levels consistent with the 1-out-of-10-year forecast, with the same underlying economic drivers as shown in the base forecast scenario.

Figure 3: Energy Forecast Outcomes by Weather Probability



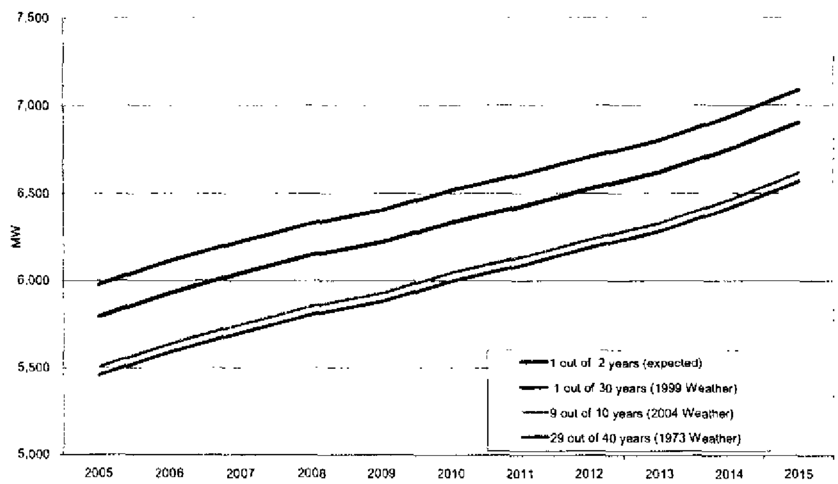
The "1 out of 2" years forecast line shows retail energy sales assuming the average weather year over the 32-year period. We note that this "distribution average" is not the same as normal weather. This thinking is consistent with research findings by Chuck Doswell of the National Severe Storms Laboratory in Norman, Oklahoma. Mr. Doswell suggests that, "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 that there is a 50% probability that retail energy sales will reach this level or higher. The normal weather forecast is actually nearer to the lower end of the distribution, which is approximately 1.3% (370,000 MWh) below the 50% probability line. Now consider the 1-out-of-30-years forecast. This line, which is over 1,000,000 MWh higher than the normal weather forecast, shows energy sales under more extreme weather events occurring just 3.6% of the time. Conversely, the lower bound forecast (29-out-of-30 year case) shows that sales may fall below the normal weather forecast by approximately 145,000 MWh if weather is milder than normal, given expected economic performance.

Figure 4 shows a similar graph for the load responsibility distribution. The weather modeling indicates that the 95% confidence interval has a range of over 520 MW, with the upper bound nearly 190 MW higher than the load under expected weather conditions, and a lower bound over 330 MW lower than the expected load

2 Doswell, Chuck, "Misconceptions about what is 'Normal' for the Atmosphere", 1997.

Figure 4: Load Responsibility Outcomes by Weather Probability



Economic Outlook

OG&E's load forecast relies on recent historical relationships between economic variables and customer loads and independently produced service area economic and population growth forecasts. As has been the case since 2001, historical and forecast economic variables (drivers) are derived from the following:

- The Oklahoma Economic Outlook, prepared by the Oklahoma State University (OSU) College of Business Administration, Department of Economics and Legal Studies
- The Arkansas Economic Outlook, prepared by the University of Arkansas Little Rock (UALR) Institute for Economic Advancement

OSU and UALR forecasts are derived from a combination of national economic forecasts prepared by Global Insight and their own state and local economic models. Both the Oklahoma Economic Outlook and the Arkansas Economic Outlook were produced in November 2004, and OSU developed a mid-2005 outlook update in June 2004.[3]

U.S. National Forecast

Economic output has continued to expand at an impressive rate since the recession's end three years ago. While forecasts for real Gross Domestic Product suggest that the 2005 national economy has slowed markedly, this is primarily due to the fact that 2004 growth rates were not sustainable. Real US GDP in 2004 was 4.5% and is now making a slow transition to a new intermediate-term real growth rate of 3%.

State of Oklahoma Forecast

State GDP and real income rapidly accelerated in the fourth quarter of 2004 and were on pace to slightly exceed OSU's initial 2005 forecast. Various state economic activity measures confirm that state growth is closely tracking national conditions and likely peaked in the past three to six months as well. State employment growth surged to a 2.8%annual rate in the first quarter of 2005 resulting from 10,000 new state-added jobs. Personal income growth increased at a 7.1% pace during the past four quarters and reached an annual rate of 13.3% in the fourth quarter of 2004.

The state economy is thriving in the current low interest and inflation rate environment. This is contributing to the resurging workers in most industries and is facilitating strong productivity and a booming housing market. The only factors currently weighing on the state economy are Tulsa's underperformance relative to the rest of the state, the ongoing manufacturing slump, and stubbornly high energy prices. Fortunately, for energy producing states such as Oklahoma, high energy prices offer an offsetting source of economic growth stimulus.

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[3] This section, through the "State of Arkansas Forecast" section, contains a brief summary of the information contained in the OSU (http://economy.okstate.edu/outlook) and UALR (Arkansas Economic Outlook, Vol. 21, No. 1, 2004) forecasts, and some of the text is verbatim.

The job formation and income growth pace is not sustainable and suggests that the state will slow slightly to a more moderate pace throughout the remainder of this year. Oklahoma is now expected to add jobs in 2005 at a slightly faster rate than the nation, expanding 1.9% versus the nation's 1.7%.

The latest personal income release suggests that the state is maintaining recent income gains relative to the nation. State per capita personal income relative to the nation has jumped from 82% to 86% since 2000. However, based on data, gains have mostly been enjoyed by both rural areas and the Oklahoma City metro area. Oklahoma City per capita income has increased from 89% of the national level to a forecasted 94% in 2005. State-level gains were achieved despite Tulsa's weak economic growth relative to the rest of the state, with 2001 income falling from 103% of the national level per person to a forecasted 98% for 2005.

Oklahoma City Metropolitan Area

Oklahoma City was the state's best performing area during the national recession. It continues to add jobs at a faster rate than both the state and nation. The forecast calls for Oklahoma City to add 11,200 new jobs this year, expanding at a 2.1% rate. This exceeds both the 1.9% rate expected for the state and the 1.7% rate for the nation. Job growth in the OKC area is broadly based, and nearly every major industry sector is on pace to post a 2005 job gain.

State and local government expect large gains with 2,400 jobs, while leisure and hospitality expect 2,200 jobs. Oklahoma City's revitalized oil and gas sector is expected to add an additional 1,000 jobs throughout 2005. Exceptions for positive job growth include modest losses in professional, scientific and technical services with 100 jobs and durable goods manufacturing with 330 jobs. The Oklahoma City GM plant remains a concern for durable goods manufacturing in the near and intermediate term for both the state and Oklahoma City region. Real income growth in the Oklahoma City area is estimated to have increased 5.0% in 2004 and is expected to ease only slightly to 4.9% for all of 2005.

State of Arkansas Forecast

According to UALR's November 2004 economic forecast, the Arkansas economy is experiencing economic gains consistent with national recovery and protracted expansion. State gains are fractionally below the national experience due to lack of local advantages. Contributing sectors from the previous cycle in the first half of the 1990s are largely absent in this case.

Sector gains in manufacturing have been limited to rebound in production and order rates, while employment gains remain illusory. No net employment gains are expected in this short-term forecast for either the durable goods or nondurable goods sectors. A major change in export growth or new industry development (auto assembly) would be required to alter current expectations.

The state economy continues to benefit from significant business operating rate improvements and gradual employment improvement. Elevated sales and use tax revenue growth at the state and local levels points to increased business spending and personal consumption driven in part by incremental growth of wage earnings and average weekly work hours.

Economic Drivers for Energy Forecast

Table 3 below shows key economic drivers and the associated OG&E econometric models they support, as well as historical and forecast growth rates from UALR and OSU for their 2005 forecasts.

Table 3: Economic Drivers' Growth Rates, 2005 Forecast

Economic Drivers and Models	Average Economic Driver Annual Growth Rates		
	1994 - 2004	2005 – 2009	2010 – 2015
Arkansas			
Street lighting: Arkansas Population	1.1%	0.6%	0.6%
Residential: Real Non Farm Income	3.0%	2.2%	1.6%
Commercial: Real Non Farm Income	3.0%	2.2%	1.6%
Public Authority: Nominal Public Authority GSP	4.8%	4.0%	4.3%
Industrial: Real Gross State Product	3.1%	3.7%	3.5%
Oklahoma			
Street Lighting: OKC Population	1.1%	1.1%	1.1%
Residential: OKC Real Personal Income	3.2%	3.1%	2.6%
Commercial: OKC Real Personal Income	3.2%	3.1%	2.6%
Public Authority: Real Oklahoma GSP	2.7%	2.9%	3.2%
Industrial: Real Oklahoma GSP	2.7%	2.9%	3.2%
Petroleum: U.S. Natural Gas Price	14.8%	1.6%	3.4%

Load Responsibility Peak Demand Forecasting Model

This section describes the 2005 load responsibility peak demand forecasting model. The forecast follows a discussion of basic methodology and related hourly econometric framework enhancements for 2005.

Peak Demand Forecasting Methodology

Econometric Modeling Framework

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

The dependent variable is normalized load responsibility on the OG&E system less OMPA PSA loads and includes line losses. Key independent variables include:

- Cooling degree hours, base 76. This cooling degree hour variable is calculated in a matter 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 so-called "topping off" effect – a reduction in the *rate* of load increases at very high temperatures
- A misery buildup variable, which accounts for two additional weather phenomena beyond the current hourly temperature:
    - NOAA's misery index reflecting the combined effects of humidity and warm temperatures
    - The build-up or duration of the misery index, which is captured through the weighted average of past hourly values of a heat 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

[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.

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, interacted with the weather variables in most of the hourly equations.

Relevant weather stations are shown below in Table 4, along with the OG&E population estimates from the 2000 census used to weight the data from each station:

Table 4: Weather Station Weights

Weather Station	Population in OG&E Territory	Weight (% of OG&E population)
Oklahoma City - Will Rodgers	1,215,619	63.4%
Fort Smith	285,644	14.9%
Guthrie	154,327	8.0%
Stillwater[5]	153,029	8.0%
Muskogee	109,834	5.7%

Forecasting Peak Loads

The peak demand forecast is generated via a probabilistic approach by using all 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 1973 to 2004 through the peak demand model and also alternates the weather year "starting day" seven times so that extreme weekday (weekend) weather event probability is treated directly in the simulations. With a matrix of 32 weather years by seven days, the 2005 forecast has a total of 224 simulations for each hour.

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

- Hourly load forecasts for each year in the forecast horizon (2005-2014) are obtained by multiplying model coefficients with the corresponding values of weather-related variables. As described above, this step generates 224 forecasts.
- For each forecast year, we first rank these 224 annual load forecasts and then 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 during between 3:00 p.m. and 7:00 p.m. (central daylight time), with the great majority occurring at 5:00 p.m.

Table 5 below illustrates the mapping between event occurrence probability and corresponding weather years. The interpretation of the results is as follows. The expected load projections

[5] While OG&E does not serve Stillwater, this weather station was the northernmost station within the required weather history.

associated with a 1-out-of-2-years (the average weather year) event are obtained from a 1984 weather-year simulation. 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. Similarly, the 1991 actual weather corresponds to an event that happens in at least three out of four years. In this case, the peak load will be below this level 25% of the time and above this level 75% of the time.

Table 5: Probability Assignments

Event Occurrence[6]	Occurrence Probability	Weather Year
1 out of 30 years	3%	1998
1 out of 10 years	10%	1978
1 out of 4 years	25%	1981
1 out of 2 years	50%	1984
3 out of 4 years	75%	1991
9 out of 10 years	90%	2004
29 out of 30 years	97%	1973

Expected Loads by Weather Probability

Table 6 and Figure 5 summarize the peak load model forecasts with a 95% percent confidence interval around potential weather events, assuming no changes in the expected economic outlook. These estimates exclude OMPA PSA, and are unadjusted for changes in FERC loads.[7] The interpretation of these results is as follows. The 1-out-of-2- years or "expected" forecast shows the peak demand level given the average of all weather years. In this case, there is a 50% probability that the peak load will reach this load level or higher. Now consider the 1-out-of-10-years forecast. This forecast, which is approximately 140 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. The key area of uncertainty is in ***which*** year this event will occur.

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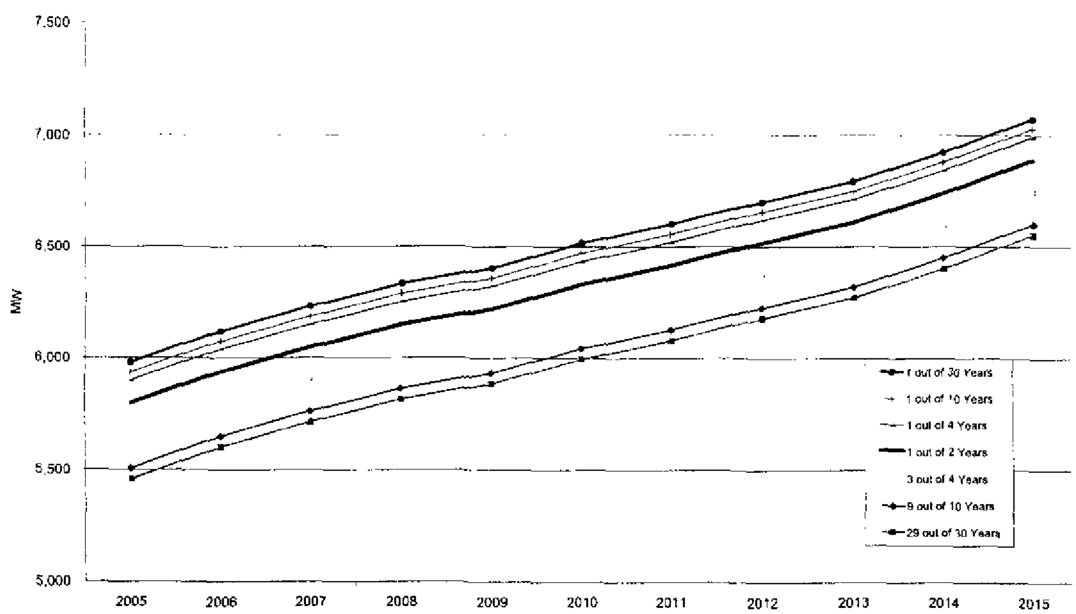
6 This means that the weather is at least as hot as in X out of Y years.

7 The load responsibility forecast model results are further adjusted for changes in FERC wholesale loads in Table 5. The 95% confidence interval around weather events for the FERC adjusted load responsibility forecast is provided in the Executive Summary (see Figure 4).

Table 6: Peak Demand Model Forecasts by Weather Probability (Excludes FERC Adjustments)

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
2005	5,980	5,934	5,898	5,796	5,583	5,507	5,459
2006	6,122	6,076	6,040	5,938	5,725	5,649	5,601
2007	6,233	6,188	6,151	6,049	5,836	5,760	5,712
2008	6,334	6,289	6,253	6,151	5,938	5,862	5,814
2009	6,404	6,359	6,322	6,220	6,008	5,931	5,883
2010	6,516	6,471	6,434	6,332	6,120	6,044	5,995
2011	6,600	6,555	6,518	6,417	6,204	6,128	6,079
2012	6,701	6,656	6,619	6,517	6,304	6,228	6,180
2013	6,793	6,747	6,711	6,609	6,396	6,320	6,272
2014	6,924	6,878	6,842	6,740	6,527	6,451	6,403
2015	7,073	7,028	6,992	6,890	6,677	6,601	6,553

Figure 5: Peak Demand Model Forecasts by Weather Probability (Excludes FERC Adjustments)



It is possible to have significantly different weather conditions from one forecast year to another. Specifically, one can see how it might be possible one year to have a low peak load forecast corresponding to an almost average weather year, such as a 1-out-of-2-years weather event, and a much higher peak load forecast under more extreme weather conditions, as in a 1-out-of-40-years case, in the following year. In this case, dramatic weather condition changes, not economic growth, are responsible for the large difference in peak load forecasts for these two years. Conversely, it is possible for the peak load to decline from one year to the next even with underlying economic growth. Overall, the 95% confidence interval associated with weather conditions represents a significant source of risk responsible for over 500 MW of potential peak load variability.

The 1-out-of-2-year (distribution average) case represents the "point estimate" from which further FERC adjustments and resource planning decisions are made. On average, peak loads are expected to grow at annual rate of about 2.0% *before* FERC adjustments, which are discussed below.

FERC Adjustments

FERC adjustments are conducted in two steps. First, the OMPA PSA wholesale load contract is added to the normalized load responsibility forecast from the model. Second, expiring (new) contracts are subtracted (added) to obtain final 2005 Load Responsibility forecasts. These adjustments and the resulting forecast are shown in Table 7 below.

Table 7: 2005 Load Responsibility Forecast

Demand (MW)	2004*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
FERC Load (without losses)												
MUNICIPAL	11.1	11.4	11.3	11.4	11.5	11.6	11.7	11.9	12.0	12.1	12.2	12.4
COOPERATIVE	210.5	215.4	212.8	219.7	226.5	233.3	240.2	247.0	253.8	260.6	267.5	274.3
SPA	32.1	32.9	32.7	32.9	33.2	33.5	33.8	34.0	34.3	34.6	34.9	35.1
OMPA PSA	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
MEAM & MDEA	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Total FERC Load (w/o losses)	288.7	294.6	291.8	299.0	306.2	313.4	320.7	327.9	335.1	342.3	349.6	356.8
Losses	25.0	25.5	25.2	25.8	26.5	27.1	27.7	28.3	29.0	29.6	30.2	30.8
Total FERC Load (losses added)	**313.7**	**320.1**	**317.0**	**324.8**	**332.7**	**340.5**	**348.4**	**356.2**	**364.1**	**371.9**	**379.8**	**387.6**
Percentage Change in Total FERC Load		2.04%	-0.95%	2.47%	2.41%	2.36%	2.31%	2.26%	2.21%	2.16%	2.11%	2.07%
Total Retail Load (with losses)	**5,375**	**5,500**	**5,635**	**5,740**	**5,837**	**5,903**	**6,009**	**6,089**	**6,185**	**6,272**	**6,396**	**6,538**
Percentage Change in Total Retail Load		2.32%	2.45%	1.88%	1.68%	1.13%	1.80%	1.33%	1.57%	1.41%	1.98%	2.22%
Load Responsibility (with losses)												
Load Responsibility = *Total Retail Load* + FERC, Losses Added (includes curtailable load)	**5,689**	**5,820**	**5,952**	**6,065**	**6,169**	**6,243**	**6,358**	**6,445**	**6,549**	**6,643**	**6,776**	**6,926**
Percentage Change in Load Responsibility		2.31%	2.26%	1.91%	1.72%	1.20%	1.83%	1.38%	1.60%	1.45%	1.99%	2.21%
Load Factor												
Load Responsibility = Total Retail Load + FERC, Losses Added	5,689	5,820	5,952	6,065	6,169	6,243	6,358	6,445	6,549	6,643	6,776	6,926
Total Retail Sales + FERC, Losses Added (See Table III.5)	26,847,686	27,546,765	28,245,496	28,839,705	29,385,767	29,772,912	30,373,873	30,835,384	31,380,059	31,880,670	32,581,645	33,378,233
Load Factor	53.87%	54.03%	54.17%	54.28%	54.37%	54.44%	54.54%	54.61%	54.70%	54.78%	54.89%	55.02%

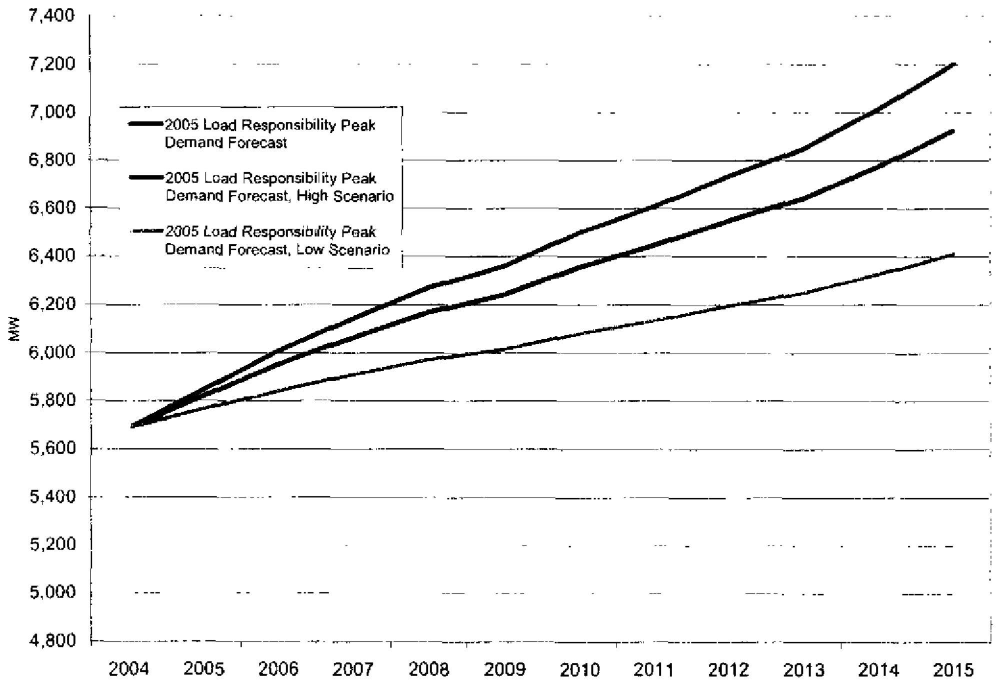
* Load Responsibility for 2004 is weather adjusted; actual value was 5,460.

Economic Uncertainty

OG&E and Quantec developed "high" and "low" economic growth scenarios for the expected load responsibility forecast. As discussed further in the section *Retail Customer Forecasting Models*, economic scenarios are based on alternate assumptions of economic activity over the next decade.

The load responsibility peak demand forecast scenarios are shown in Figure 6. These are developed by multiplying the coefficient on retail energy sales in the peak demand model by the differences in the retail sales scenarios in the *Retail Customer Forecasting Models* section.

Figure 6: 2005 Load Responsibility Peak Demand Economic Scenarios



Retail Energy Models

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

Econometric Modeling Process

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

Step 1. 2004 forecast results review to show which segments require the most attention to alternative model specifications and visual inspection of the each sales series to capture sudden changes in usage that might require dummy variables.

Step 2. Initial estimation using 2004 model specification.

Step 3. Inspection of goodness-of-fit and other important statistics (e.g., R-square, t-statistics, multicollinearity statistics) and 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.

Approximately ten to 20 models were estimated for each segment, with 2004 data held as an "out-of-sample" forecasting test period. The final model was not always the one with the "best fit." The overriding selection criterion is 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.

Tables 8 and 9 illustrate the final model variables used for Oklahoma and Arkansas, respectively. It is interesting to note that employment was not in any model's final specification. As of 1997, all OG&E non-residential energy sales models used employment as a predictor of energy sales, consistent with the majority of utilities in our industry. Starting in 1998, we began to see a disconnect between employment and electricity sales, primarily due to workplace productivity effects. Over the last several years, the econometric models began using various output measures to better capture economic activity and electricity usage relationships. This progression has now led to the outcome where none of the models use employment. It is important to recognize however, that macroeconomic models have historically focused on employment rather than output. We therefore anticipate that OG&E's energy sales models' economic drivers will continue to change with the changing economic forecasting models.[8]

[8] Indeed, our discussions with OSU have indicated that they anticipate a greater focus on productivity and measures of output in the years to come.

Table 8: Oklahoma Energy Model Drivers, 2005

	Economic Drivers Oklahoma Economic Outlook	Other Drivers
Residential	Real OKC Income	Real Residential electric price, Heating-Degree Days (HDD), Cooling-Degree Days (CDD)
Commercial	Real OKC Income	Real Commercial electric price, HDD, CDD
Industrial	Real Oklahoma GSP	Nominal OKC Manufacturing Output, Real Industrial electric price
Petroleum	Nominal Natural Gas Price	Nominal Electric Price
Public Authority	Real Oklahoma GSP	CDD, HDD, Real Public Authority Electric Price
Street lighting	OKC population	Nominal Electric Price

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

Table 9: Arkansas Energy Model Drivers, 2005

	Economic Drivers Arkansas Economic Outlook	Other Drivers
Residential	Real Non Farm Income	HDD, CDD
Commercial	Real Non Farm Income	HDD, CDD
Industrial	Real Gross State Product	
Public Authority	Nominal Public Authority GSP	CDD, HDD
Street lighting	Arkansas Population	

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

2005 Energy Forecast

Retail Forecast

Table 10 summarizes the 2005 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 23,607 GWh in 2004 to 29,511 GWh in 2015, which translates into a 25% increase over OG&E's planning horizon.

Projected growth rates associated with these data are similar to those observed over the last decade. Weather-normalized sales grew by approximately 1.9% annually from 1994 through 2004. Growth is projected to be slightly higher over the first half of the next decade (2.1%), consistent with the higher economic growth rates noted in the *Economic Outlook* section of this report. Sales growth in the 2010-2015 period will be slightly lower (1.9%), again consistent with economic driver growth rate projected reductions.

FERC Adjustments

OG&E provided Quantec with FERC wholesale contracts and associated changes from 2004 through the 2015 forecast horizon. Table 11 combines this information with the retail energy forecast from Table 10, yielding the final 2005 total energy sales forecast.

Table 10: 2005 Retail Energy Forecast (MWh)

		Residential	Commercial	Public Authority	Street lighting	Industrial	Petroleum	Total
Arkansas	2004	678,406	706,261	116,388	8,646	1,177,913		2,687,614
	2005	690,200	732,729	120,554	8,690	1,232,934		2,785,106
	2006	700,733	756,367	123,766	8,737	1,276,029		2,865,632
	2007	709,594	776,252	127,301	8,788	1,319,400		2,941,334
	2008	718,627	796,523	131,074	8,841	1,366,375		3,021,440
	2009	726,595	814,406	134,978	8,897	1,413,797		3,098,674
	2010	733,824	830,629	139,604	8,960	1,464,418		3,177,435
	2011	740,676	846,006	144,622	9,029	1,518,851		3,259,185
	2012	747,644	861,644	149,797	9,099	1,574,831		3,343,016
	2013	755,003	878,159	155,282	9,170	1,630,140		3,427,754
	2014	763,214	896,584	161,064	9,243	1,688,630		3,518,735
	2015	772,438	917,284	167,227	9,318	1,749,855		3,616,122
Oklahoma	2004	7,500,084	5,152,656	2,560,433	81,069	3,286,128	2,477,944	21,058,314
	2005	7,630,817	5,281,842	2,646,744	81,805	3,390,044	2,542,862	21,574,114
	2006	7,798,813	5,416,013	2,716,392	82,583	3,504,377	2,637,410	22,155,588
	2007	7,954,364	5,539,480	2,793,688	83,326	3,610,828	2,619,495	22,601,181
	2008	8,138,054	5,671,345	2,878,182	84,075	3,715,938	2,509,649	22,997,243
	2009	8,240,612	5,762,902	2,952,631	84,806	3,800,222	2,406,062	23,247,235
	2010	8,409,652	5,880,706	3,038,476	85,575	3,877,422	2,404,262	23,696,093
	2011	8,511,052	5,977,621	3,118,096	86,333	3,948,583	2,369,582	24,011,267
	2012	8,646,561	6,083,736	3,208,095	87,116	4,025,129	2,351,667	24,402,304
	2013	8,732,863	6,166,447	3,292,624	87,865	4,092,029	2,379,307	24,751,135
	2014	8,897,320	6,296,179	3,399,461	88,667	4,186,857	2,413,031	25,281,515
	2015	9,079,677	6,440,698	3,515,429	89,479	4,299,720	2,470,091	25,895,094
Total OG&E	2004	8,178,490	5,858,917	2,676,821	89,715	4,464,041	2,477,944	23,745,928
	2005	8,321,017	6,014,571	2,767,298	90,495	4,622,978	2,542,862	24,359,220
	2006	8,499,546	6,172,380	2,840,158	91,320	4,780,406	2,637,410	25,021,220
	2007	8,663,958	6,315,732	2,920,989	92,114	4,930,228	2,619,495	25,542,515
	2008	8,856,681	6,467,868	3,009,256	92,916	5,082,313	2,509,649	26,018,683
	2009	8,967,207	6,577,308	3,087,609	93,703	5,214,019	2,406,062	26,345,909
	2010	9,143,476	6,711,335	3,178,080	94,535	5,341,840	2,404,262	26,873,528
	2011	9,251,728	6,823,627	3,262,718	95,362	5,467,434	2,369,582	27,270,452
	2012	9,394,205	6,945,380	3,357,892	96,215	5,599,960	2,351,667	27,745,320
	2013	9,487,866	7,044,606	3,447,906	97,035	5,722,169	2,379,307	28,178,889
	2014	9,660,534	7,192,763	3,560,525	97,910	5,875,487	2,413,031	28,800,250
	2015	9,852,115	7,357,982	3,682,656	98,797	6,049,575	2,470,091	29,511,216

Table 11: Energy Forecast Accounting for Changes in Wholesale Load

Energy (MWH)	2004 (Actual, Weather Adjusted)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
FERC Sales (without losses)												
MUNICIPAL	38,361	39,849	40,307	40,628	40,950	41,271	41,592	41,913	42,235	42,556	42,877	43,199
COOPERATIVE	950,727	998,741	990,279	1,023,980	1,057,682	1,091,385	1,125,087	1,158,789	1,192,491	1,226,193	1,259,895	1,293,597
SPA	132,379	139,620	140,497	142,094	143,690	145,286	146,883	148,479	150,076	151,672	153,269	154,865
OMPA PSA	211,411	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000
MEAM & Jonesboro	83,743	61,320	61,320	61,320	61,320	61,320	61,320	61,320	61,320	61,320	61,320	61,320
Total FERC Sales	1,416,621	1,458,530	1,451,402	1,487,022	1,522,642	1,558,262	1,593,882	1,629,502	1,665,122	1,700,741	1,736,361	1,771,981
Growth Rate in FERC sales		2.96%	-0.49%	2.45%	2.40%	2.34%	2.29%	2.23%	2.19%	2.14%	2.09%	2.05%
Retail Sales (without losses)												
Residential	8,178,490	8,321,017	8,499,547	8,663,958	8,856,681	8,967,207	9,143,476	9,251,728	9,394,205	9,487,867	9,660,533	9,852,114
Commercial	5,858,917	6,014,571	6,172,381	6,315,732	6,467,869	6,577,308	6,711,335	6,823,628	6,945,380	7,044,606	7,192,762	7,357,983
Industrial	4,464,041	4,622,978	4,780,407	4,930,228	5,082,313	5,214,019	5,341,840	5,467,434	5,599,961	5,722,170	5,875,487	6,049,575
Industrial Petroleum	2,477,944	2,542,862	2,637,410	2,619,495	2,509,649	2,406,062	2,404,262	2,369,582	2,351,667	2,379,307	2,413,031	2,470,091
Total Industrial	6,941,984	7,165,839	7,417,816	7,549,723	7,591,962	7,620,081	7,746,102	7,837,016	7,951,627	8,101,476	8,288,518	8,519,666
Public Authority and Street Lighting	2,766,537	2,857,793	2,931,478	3,013,103	3,102,172	3,181,312	3,272,615	3,358,081	3,454,107	3,544,941	3,658,434	3,781,453
Total Retail Sales	23,745,929	24,359,220	25,021,222	25,542,515	26,018,683	26,345,908	26,873,528	27,270,452	27,745,319	28,178,890	28,800,248	29,511,216
Growth Rate in Retail Sales		2.58%	2.72%	2.08%	1.86%	1.26%	2.00%	1.48%	1.74%	1.56%	2.21%	2.47%
Total MWH Sales (with losses)												
Total Retail Sales + FERC	25,162,550	25,817,751	26,472,624	27,029,537	27,541,325	27,904,170	28,467,410	28,899,954	29,410,441	29,879,631	30,536,609	31,283,198
Losses (.0718)	1,685,136	1,729,015	1,772,872	1,810,168	1,844,443	1,868,742	1,906,462	1,935,430	1,969,617	2,001,039	2,045,037	2,095,036
Total Retail Sales + FERC, Losses Added	**26,847,686**	**27,546,765**	**28,245,496**	**28,839,705**	**29,385,767**	**29,772,912**	**30,373,873**	**30,835,384**	**31,380,059**	**31,880,670**	**32,581,645**	**33,378,233**
Growth Rate in Total Sales		2.60%	2.54%	2.10%	1.89%	1.32%	2.02%	1.52%	1.77%	1.60%	2.20%	2.44%

Energy Forecast Uncertainty

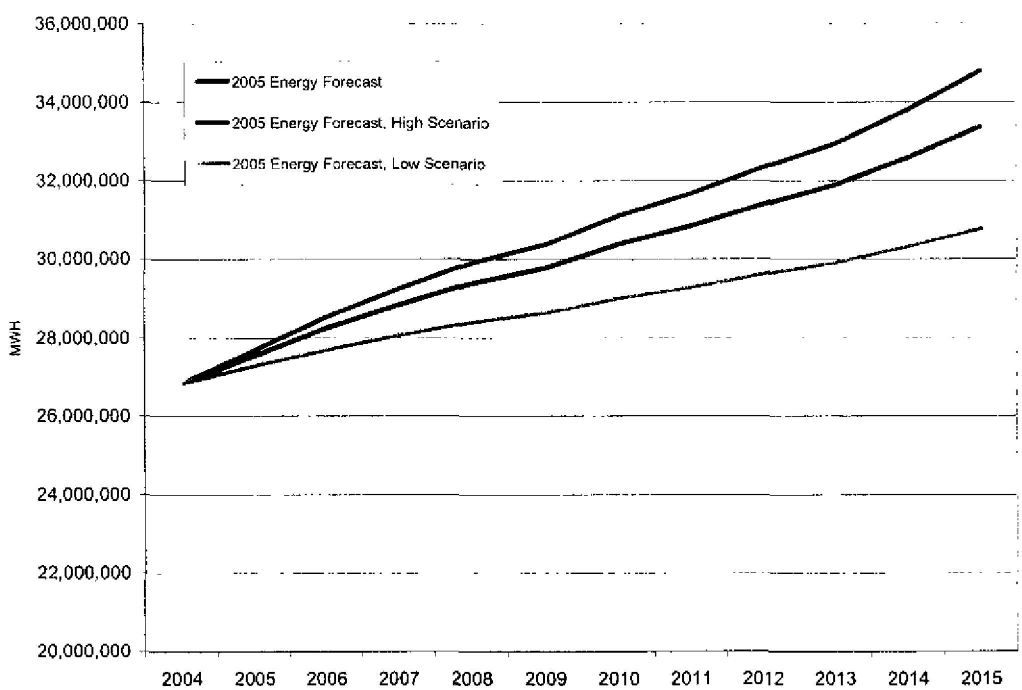
Economic Uncertainty

The economic series developed by Global Insight, OSU, and UALR represent "point" forecast estimates because these organizations do not provide alternate scenarios or probability statements.

Further discussions with OSU's macroeconomists centered around the upper growth limit potential for the Oklahoma economy and how present growth trends compared. OSU believes that state growth in the late 1990s represents the best the state could achieve. As the expected energy forecast growth rate is already approaching late 1990s levels, the high scenario reflects a growth "premium" that is only 20% higher each year than the expected case, with an average retail growth rate of 2.4% over the planning horizon. The low retail scenario incorporates a 40% reduction in the annual growth rate yielding an average retail growth rate of 1.2%. While one could use alternate growth rates for the high and low cases, our intention here is to demonstrate the resulting, compounding impact of economic uncertainty on OG&E's sales over the next decade.

The final set of energy sales forecast scenarios are shown in Figure 7. All three energy sales scenarios contain the FERC wholesale contract adjustment previously described, and include line losses.

Figure 7: 2005 Energy Forecast Economic Scenarios

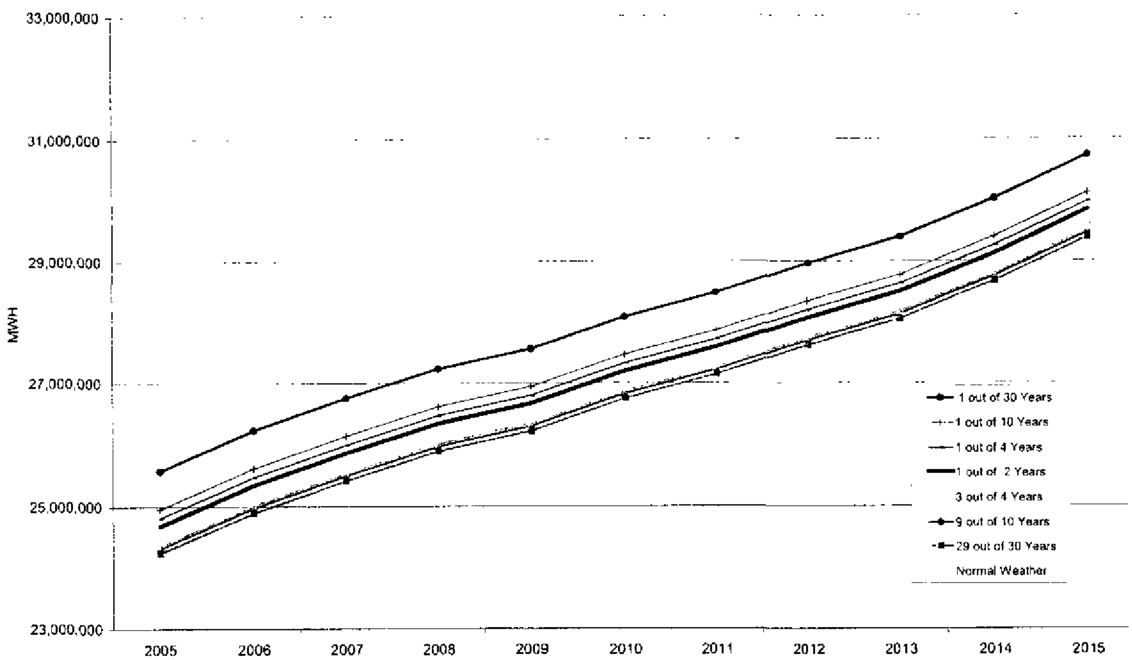


Weather Uncertainty

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 input 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 1973 to 2004 through the weather sensitive energy models and the peak demand model to develop a probability distribution of possible outcomes. Figure 8 shows the results directly from this modeling process for energy sales and excludes FERC adjustments.

Figure 8: Retail Energy Model Forecast Outcomes by Weather Probability



The results interpretation follows. The "1 out of 2" years forecast line shows the retail energy sales, assuming the average of the weather years over the 32-year period. The 1-out-of-2 years average weather line indicates that there is a 50% probability that retail energy sales will reach this level or higher. The normal weather forecast is actually near the lower end of the distribution, which is approximately 1.3% (370,000 MWh) below the 50% probability line.

Now, consider the 1-out-of-10-years forecast. This line, which is over 1,000,000 MWh higher than the normal weather forecast, shows energy sales under more extreme weather events occurring just 10% of the time. Put differently, over a 10-year planning horizon, it is likely that OG&E's retail sales will reach levels consistent with the 1-out-of-10-year forecast, with the same underlying economic drivers as shown in the base forecast scenario.

Retail Customer Forecasting Models

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

Retail Customer Econometric Modeling Process and Forecast

Approximately 5 to 10 models were estimated for each segment, with 2004 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. However, after extensive analyses, the models with the state's respective populations as primary drivers yielded the best models with the least volatility. Therefore, for each of the different sector's models in Oklahoma and Arkansas, the primary customer forecast economic drivers were the Oklahoma City and Arkansas populations, respectively.

Table 12 summarizes the 2005 annual retail customer forecast by state and sector, and for the company as a whole. Since this is the customer forecasting models' first year, we recommend using them in conjunction with existing OG&E customer forecasts over the next year or so to evaluate their performance. The best model fits were obtained for residential and commercial sectors, suggesting that these forecasts should be the most accurate.

Table 12: 2005 Retail Customer Forecast

		Residential	Commercial	Public Authority	Street lighting	Industrial	Petroleum	Total
Arkansas	2004	51,972	8,327	1,175	25	430		61,928
	2005	52,093	8,471	1,231	25	414		62,234
	2006	52,201	8,634	1,283	25	392		62,535
	2007	52,376	8,771	1,331	25	380		62,883
	2008	52,567	8,907	1,379	25	368		63,247
	2009	52,761	9,043	1,428	25	356		63,614
	2010	52,972	9,179	1,474	25	346		63,996
	2011	53,191	9,314	1,519	25	337		64,385
	2012	53,405	9,449	1,565	25	327		64,771
	2013	53,615	9,584	1,612	25	316		65,152
	2014	53,823	9,720	1,658	25	306		65,532
	2015	54,030	9,855	1,705	25	295		65,911
Oklahoma	2004	575,052	72,434	12,375	224	2,893	5,786	668,764
	2005	579,840	72,977	12,802	223	2,829	5,746	674,417
	2006	583,932	73,901	13,099	224	2,805	5,557	679,517
	2007	588,751	74,790	13,390	224	2,799	5,460	685,414
	2008	593,616	75,702	13,667	224	2,800	5,361	691,371
	2009	598,484	76,618	13,943	224	2,802	5,261	697,333
	2010	603,347	77,547	14,213	225	2,805	5,158	703,295
	2011	608,205	78,486	14,479	225	2,809	5,053	709,257
	2012	613,058	79,436	14,739	225	2,814	4,946	715,218
	2013	617,908	80,394	14,996	226	2,819	4,837	721,178
	2014	622,752	81,364	15,247	226	2,825	4,725	727,139
	2015	627,591	82,343	15,493	227	2,832	4,611	733,098
Total OG&E	2004	627,023	80,761	13,550	249	3,323	5,786	730,692
	2005	631,933	81,448	14,033	248	3,244	5,746	736,651
	2006	636,133	82,535	14,382	249	3,196	5,557	742,052
	2007	641,127	83,561	14,721	249	3,179	5,460	748,297
	2008	646,183	84,610	15,047	249	3,168	5,361	754,617
	2009	651,246	85,662	15,371	249	3,158	5,261	760,946
	2010	656,319	86,726	15,687	249	3,151	5,158	767,291
	2011	661,395	87,800	15,998	250	3,146	5,053	773,642
	2012	666,463	88,885	16,304	250	3,141	4,946	779,988
	2013	671,522	89,978	16,607	251	3,136	4,837	786,330
	2014	676,574	91,084	16,905	251	3,131	4,725	792,670
	2015	681,622	92,199	17,198	251	3,128	4,611	799,009

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 2005 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
- Economic and demographic data from Global Insight, OSU and UALR

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

Internal Company 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 "B-1" report for both Oklahoma and Arkansas jurisdictions. The B-1 database 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 in the Oklahoma forecasts. Arkansas' industrial and industrial-petroleum sales are combined as a single industrial sales variable because of the relatively small petroleum base in the Ft. Smith area. In the econometric models that have statistically significant electric price variables, these variables are defined as "average" prices (B-1 revenues divided by 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 plus Load Curtailment plus RTP-Self-Generation). The normalized load responsibility series was further adjusted for peak demand modeling purposes by subtracting highly variable OMPA PSA loads and forecasting these directly as wholesale FERC loads.

Information Obtained from External Sources

Weather Data

OG&E obtained the following information from the Department of Commerce, National Oceanic and Atmospheric Administration (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 are 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 OSU and UALR.[9] The OSU model data also includes national economic data from Global Insight Historical and forecast time series used in the econometric models include population, real income, wages and salaries, price deflators, various production and output series including industrial production and gross state product, and natural gas prices, and employment.

[9] Detailed historical and forecasted economic drivers are discussed in more detail in the *Economic Outlook* section of this report.

Appendix C – Purchased Power Procurement Plan

OG&E currently has six purchase power agreements in place. The resource plan makes the assumption that all long-term purchase power agreements are available for continuation.

The first purchase power agreement is with AES and OG&E. The initial Date of Delivery was 1/15/1991; the contract has a thirty-two year term, with three termination anniversaries by OG&E at 1/15/2008, 1/15/2013, and 1/15/2018. The contract capacity for the AES unit is for 320 MW. This contract is indexed to the OG&E average coal cost.

The second purchase power agreement is with SCI and OG&E. The Initial Date of Delivery was 9/1/2004 and the contract has a fifteen-year term. The contract capacity for SCI is 120 MW. This contract is indexed to the OG&E delivered weighted-average cost of gas (WACOG).

The third purchase power agreement is with MCPC and OG&E. The initial Date of Delivery was 1/1/1998 and the contract has a ten-year term, with two five-year renewals, the first occurring on 1/1/2008. The contract capacity for MCPC is 110 MW. This contract is indexed to the OG&E average gas cost. The MCPC contract was chosen in the resource plan for termination in various years depending on the scenario. No determination has been made whether to exercise the option to terminate the MCPC contract.

The fourth purchase power agreement is with FPL and OG&E. FPL installed and operates a wind farm with a total name plate capacity of 51 MW although OG&E only claims 3 MW of firm capacity. The initial Date of Delivery was 9/30/2003 and the contract has a fifteen-year term with a fixed cost over the lifetime of the contract.

The fifth purchase power agreement is with SPA and OG&E. The initial Date of Delivery was 6/1/1998 and the contract has a 14 year term ending on 5/31/2012. This is an energy exchange agreement and the contract capacity is 31 MW.

The sixth purchase power agreement is with Westar Energy, Inc. (WRI) & OG&E. This agreement is in place only for the summer of 2006 from 6/1/2006 through 8/31/2006. This agreement was the result of the winning bid in a summer RFP. It has a contract capacity of 440 MW and is indexed to ONEOK Gas Daily Index.

Appendix D – Proposed RFPs for Soliciting New *Resources*

Oklahoma Gas and Electric Company

Request For Proposal

For

Capacity and Energy

Resources

Years 2008 - 2010

Issued September 2006

Table of Contents

SECTION 1 - GENERAL INFORMATION 5

1.1 INTRODUCTION 5
1.2 INDEPENDENT MONITOR 6
1.3 SELF-BID PROCEDURES 6
1.3 RFP SCHEDULE 7

SECTION 2 – 2008 - 20106 CAPACITY AND ENERGY RESOURCES RFP 7

2.1 BASIC REQUIREMENTS FOR FIRM CAPACITY AND ENERGY PROPOSALS 7
2.2 PROPOSALS 7
2.3 POWER PURCHASE PROPOSALS 8
2.3.1 System Products 8
2.4 POWER PURCHASE AGREEMENT 9
2.5 RELIABLE DELIVERY 10

SECTION 3 - INSTRUCTIONS TO BIDDERS 11

3.1 CONFIDENTIAL INFORMATION AND CONFIDENTIALITY AGREEMENTS 11
3.2 MODIFICATION OR CANCELLATION OF THE RFP 11
3.3 QUESTION, COMMENT AND RESPONSE PROCESS 11
3.4 TECHNICAL CONFERENCE 12
3.5 ADDITIONAL QUESTIONS AND COMMENT SUBMISSION 12
3.6 TRANSMISSION CONTACTS 12
3.7 JOINT PROPOSALS 12
3.8 SELF BUILD PROPOSALS 13
3.9 SUBMISSION OF PROPOSALS 13

SECTION 4 - PROPOSAL EVALUATION 14

4.1 RECEIPT AND OPENING OF PROPOSALS 14
4.2 ELIGIBILITY REQUIREMENTS 14
4.3 DESCRIPTION OF THE EVALUATION PROCESS 14
4.3.1 Eligibility Requirements and Threshold Requirements Screening 15
4.3.2 Evaluation Analysis 15
4.3.3 Portfolio Evaluation 16
4.4 THRESHOLD REQUIREMENTS 16
4.4.1 Credit Threshold 16

4.5 DESCRIPTION OF PRICE RELATED EVALUATION CRITERIA....17
4.5.1 Capacity Charge....17
4.5.2 Fixed O&M Charge....18
4.5.3 Energy Charge....18
4.5.4 Fuel Transportation Charge....18
4.5.5 Variable O&M Charge....18
4.5.6 Start-Up Charge....19
4.5.7 Emissions Charges....19
4.5.8 Ancillary Services Charge....19
4.5.9 Transmission System Impact....19
4.5.10 Debt Equivalence....20
4.6 DESCRIPTION OF OTHER PRICE NON-PRICE RELATED EVALUATION CRITERIA....20
4.6.1 SPP/RTO Markets....22
4.6.2 Fuel Supply and Transportation Arrangements....22
4.6.3 Environmental Impact and Compliance....22
4.6.4 Model Contracts....23
4.6.5 Quality of Output....23

4.7 NOTIFICATION OF EVALUATION RESULTS AND NEGOTIATIONS....23

SECTION 5 – REGULATORY APPROVALS....24

SECTION 6 – RESERVATION OF RIGHTS....25

SECTION 7 – GLOSSARY OF TERMS....27

Appendix A Confidentiality Agreement Form

Appendix B Credit Evaluation Form

Appendix C Model Power Purchase Agreement

NOTICE

In the event that a Bidder perceives a conflict between this RFP and other posted information (e.g., answers to questions), this RFP document, as amended, shall prevail.

If corrections or clarifications to the RFP documents are required, OG&E will issue a "RFP Amendment" on its RFP website located at:

www.oge.com/2008RFP

Potential Bidders should check this RFP website regularly. It is the sole responsibility of the Bidder to keep up with any RFP document changes as discussed above.

SECTION 1 - GENERAL INFORMATION

1.1 Introduction

The purpose of this document is to prescribe the process by which Oklahoma Gas and Electric Company ("OG&E" or the "Company") will request and evaluate Proposals through a competitive procurement process which the Company deems, in its discretion, to provide the most reasonable cost and reliable resources to fulfill a portion of its supply-side resource need consistent with Company's resource planning requirements. The scope of this Request For Proposal ("RFP"), subject to the limitations described herein, is focused on a supply-side resource capable of delivering energy or capacity and associated energy in or to the Company's transmission system and that is capable of fulfilling the planning reserve requirements of the Southwest Power Pool ("SPP").

The Company is soliciting binding Proposals from bidders ("Bidders") in the form of Power Purchase Agreements ("PPA") for Firm Energy or Capacity with Firm Energy for the for the (3) month Peak Summer Periods (June through August) or the four (4) month Summer periods (May – August), each for calendar years 2008 through 2010.

Specifically, the Company seeks proposals for:

- Minimum of 100 MW and Maximum of 700 MW of Firm Energy (WSPP Schedule B Unit Commitment or WSPP Schedule C System Firm) for each, any, or all of the (3) month Peak Summer Periods beginning June 1st through and including August 1st or the four (4) month Peak Summer Periods beginning May 1st through and including August 1st for the years 2008, 2009, and 2010.

  OR

- Minimum of 100 MW and Maximum of 700 MW of Capacity with Firm Energy (WSPP Schedule B Unit Commitment or WSPP Schedule C System Firm) for each, any, or all of the four (4) Summer Periods beginning on the May 1st and ending on August 31st for the years 2008, 2009, and 2010.

The Company will also accept and evaluate proposals for Firm Energy or Capacity with Firm Energy for any or all years 2008 through 2010 which include, at a minimum, the Summer Periods or Peak Summer Periods for each year. However, it is anticipated that Peak Summer only proposals will provide the best value for OG&E's customers.

Proposals shall be binding upon the successful Bidder until March 28, 2007.

The Company seeks Proposals from any Bidder who is capable of meeting the conditions of this RFP. Bidders should note that the Company or an affiliate of the Company may submit a bid or bids to this RFP as contemplated by and in accordance with the Commission's Competitive Bidding Rules codified at OAC 165: Subchapter 34

OG&E, based in Oklahoma City, Oklahoma, is a wholly-owned subsidiary of OGE Energy Corp. OG&E is an operating electric public utility engaged in the generation, transmission, distribution, purchase and sale of electric energy in Oklahoma. OG&E provides wholesale and retail electric service to more than 740,000 customers in Oklahoma and Western Arkansas. OG&E's retail electric rates and services are regulated by the Oklahoma Corporation Commission ("OCC" or "the Commission"). OG&E's wholesale power and transmission rates and services are regulated by the Federal Energy Regulatory Commission ("FERC").

For capitalized terms not defined in the main text of this RFP, please refer to Section 7, Glossary of Terms.

1.2 Independent Monitor

OG&E is committed to a fair solicitation process. The evaluation criteria and process are designed to ensure a fair solicitation process and to provide Bidders with information on how the Proposals will be evaluated and what the Company deems as important aspects of a Proposal. The Commission, pursuant to OAC 165:35-34-3(b) may select an Independent Monitor ("IM") for this solicitation who shall be financially and substantively independent from OG&E, its affiliates, and any potential Bidders. The Commission, a representative of the Attorney General of the State of Oklahoma ("AG") and the IM will monitor the RFP process and, to the extent necessary, review the draft RFP and the Company's evaluation of Proposals, reporting to the Commission on its independent evaluation of the bids received pursuant to this RFP and attempting to resolve any differences with OG&E regarding the winning Bid(s).

1.3 Self-Bid Procedures

Procedures for this RFP call for objective, arm's-length dealing with respect to agents of the Company who are developing self-bid Proposals ("Bid Team"). Appropriate procedures are in place to safeguard against the Bid Team receiving undue preferential treatment and preferential access to information. Additional procedural provisions require OG&E to protect the confidentiality of Proposals and Bidder information and to ensure such information is not improperly used by OG&E or its Affiliates.

Specifically prohibited is the communication, directly or indirectly, of material non-public information about or derived from OG&E selectively to the Bid Team, as well as any preference by the OG&E Evaluation Team expressed in any way whatsoever for self-bid Proposals per se.

Accordingly, in this RFP there is pre-established operational independence between the OG&E Evaluation Team and the Bid Team to ensure that any Proposals submitted by the

Bid Team will not have any material advantage in the selection process versus Proposals submitted by third-party Bidders.

1.4 RFP Schedule

The schedule for the RFP is shown below. As circumstances warrant, the Company, in its judgment and discretion, may change this schedule and in that event OG&E will inform all participants as far in advance as reasonably possible and the information will be posted on the RFP website located at www.oge.com/2008RFP. The Company will consult with the OCC, AG and IM prior to announcing any significant change to the schedule shown below.

Draft RFP Issued:	09/01/06
Technical Conference:	10/11/06
Posting Deadline for all Questions:	10/25/06
Comments Due:	11/22/06
Issue Final RFP:	12/20/06
Self-Bid Proposals Due:	02/13/07
Proposals Due:	02/14/07
Selection of Award Group:	03/28/07
Execute Final Contracts:	06/29/07

SECTION 2 – 2008 – 2010 CAPACITY AND ENERGY RESOURCES RFP

2.1 Basic Requirements for Firm Energy or Capacity With Firm Energy Proposals

The Company is seeking Proposals for Firm Energy or Capacity with Firm Energy resources. Resource Capabilities shall be in accordance with the testing procedures defined in Section 12 of SPP Criteria--Electrical Facility Ratings..

OG&E prefers Proposals with points of delivery connected directly to OG&E's transmission system. All Proposals, regardless of the location of the generation resource, will be judged based upon their impact on OG&E's transmission facilities, including the cost of any required system upgrades, and to the extent they can be determined, on neighboring transmission systems.

2.2 Proposals

Bidders may submit up to [four] Proposals which shall be comprised of the information provided by the Bidder in the RFP Response Package.

OG&E will determine the Proposals to be included on the short-list based on its evaluation of the Proposals. At no point in the evaluation process will Bidders have the opportunity to unilaterally change their Proposal.

2.3 Power Purchase Proposals

The Company seeks Proposals that have clear and definable pricing characteristics. It prefers firm energy proposals based upon unit heat rates and fuel index pricing. Any capacity with firm energy proposals should contain a fixed price, throughout the term of the Proposal for capacity, stated in $/kW-month or $/kW-year for each month or each year of the proposal. Bidders shall not offer Proposals with indexed pricing (e.g., Producer Price Index, Consumer Price Index, interest rates, etc.) other than gas price indices.

Except as provided in Section 2.5, Bidders proposing PPA products are responsible for all costs to deliver those products to OG&E including, but not limited to: costs of transmission service, upgrades and new construction of transmission facilities located outside of the OG&E SPP footprint, costs of transmission congestion; costs of ancillary services, and any fees or taxes, present and future, over the term of the Proposal. (see Sections 2.5 and 4.3.5. This must be expressly confirmed in Bidder's Proposals.

Bidder generation resources interconnected to OG&E's transmission system within the OGE SPP Balancing Area near OG&E's large load centers are preferred.

OG&E prefers products that provide scheduling flexibility commensurate with the operating characteristics of the proposed generation assets. OG&E prefers the right to dispatch these products at any load level within the source generator's operating limits, and to start and stop as needed to serve OG&E's operational needs.

Requirements of the PPA may be met through a slice-of-system, existing generation facilities or proposed new generating facilities.

2.3.1 System Products

Company encourages the Bidder to submit RFP Proposals for capacity and energy products supported by a single generating facility or by a system of generating facilities. Such slice-of-system ("System") Proposals should meet the product criteria stated above and elsewhere in this RFP. Because the characteristics of a System are not defined by reference to the capabilities of a particular generating unit, the Bidder should specify with particularity the capabilities of its System product. The Bidder should modify its RFP Response Package to the extent necessary to include this information. The Bidder should include an overview of its System and information on the particular generating facilities supporting its System Proposal.

In order to assist Bidders wishing to propose System products, Company is providing the following non-exhaustive list of the capabilities that should be described in such Proposals. Where appropriate, Company has specified minimum standards that must be met by a System product.

(i) Quality: Company prefers System products that are Firm. The Bidder should specify the level of firmness of its System product and state any excuses from performance with particularity (e.g., the number of units or percentage of system that must be off-line prior to any diminishment in System product service).

(ii) Scheduling: The Bidder should specify any minimum notice times prior to scheduling and dispatch of the System product by Company. In particular, the Bidder should specify if its System product must be scheduled on a day-ahead basis and the extent to which its system may be scheduled on an same day basis.

(iii) Scheduling Limits: The Bidder should state any minimum or maximum loading constraints as well as the rate at which Company may change the loading of the System over a given time period.

(iv) Starts: The Bidder should state the number of "starts" – the scheduling of at least minimum load after the System has been scheduled to zero – over a given time, any mandatory downtime or uptime, and the cost, if any, of starting the System.

(v) Delivery Point: The Bidder should specify the Delivery Point for energy and ancillary services from the System and, if more than one point, any information necessary to determine the allocation of energy and ancillary services among those points.

(vi) Ancillary Services: The Bidder should specify the ancillary services that Company will have the right to utilize from the System and, if such ancillary services are not under the direct dispatch and control of Company, the manner in which aggregate System revenues from those services will be determined and allocated to Company.

2.4 Power Purchase Agreement

PPA Proposals should have fuel supply and transportation flexibility commensurate with the Proposal's operational and dispatch flexibility. The Bidder shall clearly describe the flexibility of its fuel supply and transportation arrangements serving its generation units. *The Company's analysis will be weighted to reflect the value such fuel supply and* transportation flexibility affords Company's operations.

Regardless of the specific fuel used by the generating facilities or system that Bidder relies on in its Proposal, Bidder shall describe its proposed fuel supply plan in detail including its proposed primary fuel supply and transportation and its backup alternatives.

With respect to the energy and ancillaries price component of PPA Proposals for natural gas generating facilities, energy pricing should be based on a stated heat rate (in MMBtu/MWh) for each applicable period and a natural gas daily or monthly index applicable to Oklahoma (i.e., ANR-OK, NGPL-TexOK, NGPL – Mid-Con, Center Point (Reliant East), OneOK, PEPL, Southern Star). If Bidder desires to utilize a different energy and ancillaries pricing methodology, Bidder should include the description of any index used, whether the pricing is daily or monthly, as well as any escalation factors or other costs to the Company which should be considered.

Regardless of the specific fuel used by the generating facilities or system that Bidder relies on in its Proposal, Bidder shall explain its proposed fuel supply plan in detail including its proposed primary fuel supply and transportation and its backup alternatives. The Bidder is encouraged to suggest as part of its Proposal terms and conditions for inclusion in the PPA under which Company would be able to lock-in the variable fuel price component of the energy and ancillaries charges from time to time during the term of the PPA.

In the event that a new fuel supply or transportation arrangement is required to enable Bidder to meet its delivery obligation to Company, all relevant information with respect to such proposed arrangements should be provided as part of Bidder's Proposal in sufficient detail to allow its feasibility to be evaluated by the Company's RFP evaluation teams.

2.5 Reliable Delivery

Bidders are required to deliver firm energy or capacity with firm energy to the OGE SPP Control or Balancing Area. OG&E expects to use Network Integrated Transmission Service under the SPP Open Access Transmission Tariff ("OATT") for resources within the SPP RTO footprint. Approval of transmission service by SPP for requests where the resources are located on OG&E's transmission system are expected to require fewer transmission upgrades than resources located elsewhere.

Proposals for products originating outside the SPP RTO footprint shall specify the Bidder's obligation to reserve, provide for, and pay for firm transmission service to the SPP RTO footprint. Such Proposals shall specify all pertinent details of proposed firm transmission paths, services and arrangements and shall specify all-inclusive pricing to the SPP RTO footprint, including all transmission costs and agreements in place to deliver such firm capacity, energy and associated electric products.

Each Bidder offering firm energy or capacity with firm energy originating outside the SPP RTO footprint must provide the factual basis for its assumption that a firm transmission reservation can be obtained to deliver power into OG&E's transmission system.

OG&E will undertake its own analysis for delivery of firm energy or capacity with firm energy [and associated electrical products] and use the results in the Proposal evaluation phase. A Bidder, at its sole option and liability, can contract with applicable transmission provider(s) and pay for any studies it wishes to provide OG&E prior to evaluation of Proposals.

OG&E will perform more detailed studies at its own expense to estimate the cost of any required transmission upgrades. These transmission studies will be done in a manner similar to the transmission studies required by SPP. Company will use the best available information and data to perform these studies, however, there is no expectation that the study results will precisely match studies that will be ultimately performed by SPP to approve OG&E's request for Network Integration Transmission Service.

After the Award Group is determined and negotiations are completed, Company will request Network Integration Transmission Service under the SPP OATT. Bidders sourcing their offer outside the SPP will be expected to make similar firm transmission service arrangements with transmission providers outside the SPP at that time.

SECTION 3 - INSTRUCTIONS TO BIDDERS

3.1 Confidential Information and Confidentiality Agreements

The Company, its agents, the OCC, AG and the IM will treat as confidential all Proposals submitted by Bidders. Bidders shall submit their Proposals with the knowledge and understanding that regardless of confidentiality any information submitted by them is subject to disclosure to the Commission or any other governmental authority or judicial body with jurisdiction relating to these matters and may be subject to legal discovery. In the event that the Company, in its judgment and discretion, determines that information contained in any question, response, or other communication between it and a Bidder that is not contained in the Bidder's Proposal requires confidential treatment, a Confidentiality Agreement (Appendix A) will be submitted to the Bidder. The Company will ensure that all Bidders have access to the same information from the Company and that no Bidder will have selective or otherwise preferential access to market sensitive information from the Company through this RFP.

3.2 Modification or Cancellation of the RFP

In addition to modifying the proposed schedule, as provided in Section 1.1, OG&E reserves the right, in its judgment and discretion, but subject to prior consultation with the OCC, AG and IM, to modify or cancel this RFP. OG&E will post a notice on its RFP website of any such changes, cancellations, or schedule changes.

3.3 Question, Comment and Response Process

All questions and comments submitted by Bidders, as well as OG&E's responses to such questions, will be posted on the RFP website located at www.oge.com/2008RFP. The official response to questions submitted by Bidders is the written response posted to the website. OG&E's objective in posting these questions, comments and responses is to ensure all Bidders have equal access to information that may be potentially relevant to their respective Proposals.

Requests for access to the website Question and Answer section should be sent via e-mail to 2008RFP@oge.com. Requests should include: (1) contact name, (2) company, (3) mailing address, (4) phone number and (5) e-mail address. A user ID and password will be issued and communicated through a return message to the requester's e-mail address.

Any unsolicited contact by Bidder with any OG&E or its Affiliates personnel concerning this RFP is not permitted and may constitute grounds for disqualification.

3.4 Technical Conference

OG&E will conduct a Technical Conference for persons interested in this RFP on October 11, 2006 at the OG&E headquarters located at 321 North Harvey Street, Oklahoma City, Oklahoma. The primary purpose of this conference will be to review the RFP and to afford interested persons the opportunity to ask questions and make suggestions. Potential Bidders were encouraged, but not required, to attend and actively participate. Following the Technical Conference, OG&E's complete presentation and the Questions and Answers were posted on its RFP website. The official response to questions submitted by Bidders is the written response posted to the website.

3.5 Additional Questions and Comment Submission

Following the Technical Conference, Bidders have until 5:00 p.m. CPT on October 25, 2006 to submit final questions. The Company will respond to all questions by November 8, 2006 Comments on the RFP must be submitted to the Company by 5:00 p.m. CPT on November 22, 2006. Comments may be submitted through e-mail to 2008 RFP@oge.com or by mail to the address specified in Section 3.13.

The Final RFP will be issued no later than December 20, 2006. Following issuance of the *Final RFP, Bidders are encouraged to continue to send questions related to the substance* of the RFP to the Company RFP website. All questions should be submitted no later than 5:00 p.m. CPT January 12, 2007 After that time, the website will be closed for further questions. Questions submitted at least five days in advance of the Pre-bid Conference will be addressed during the Conference. OG&E will answer all questions submitted to its RFP website, and will post the answers on the website by January 26, 2007.

3.6 Transmission Contacts

Any inquiries related to OG&E's transmission system or services must be directed to the SPP.

3.7 Joint Proposals

No Bidder may act through a partnership, joint venture, consortium, or other association or otherwise act in concert with any other person unless, as part of its Proposal, it provides written notification to OG&E and fully identifies all partners, joint venturers, members or other entities or persons thereof.

3.8 Self Build Proposals

Self Build Proposals will submit information no later than 3:00 p.m. CPT, February 13, 2007

3.9 Submission of Proposals

Proposals, other than Self Build Proposals, will be accepted no later than 3:00 p.m., CPT, February 14, 2007. Any Proposals received later than the applicable due date and time will be considered nonconforming and will be rejected.

Proposals must be signed by an officer or other agent of the Bidder duly authorized to make such Proposals by the Bidder's board of directors or similar governing body. Proposals must certify in writing that all Proposal terms, including pricing, have been approved by the Bidder's board of directors or other governing authority.

All Proposal terms and conditions shall be specified in detail in the RFP Response Package. Proposal provisions including, but not limited to, term and pricing, shall remain in effect until March 28, 2007.

All Proposals, along with the appropriate Proposal Submittal Fee, must be delivered by hand or by express, certified or registered mail to:

Oklahoma Gas and Electric Company
Attention: 2008-2010 Capacity and Energy RFP
c/o Kim Morphis
P.O. Box 321, MC GB 58
Oklahoma City, Oklahoma 73101-0321
Telephone : 405-553-2110

In order to facilitate an objective, impartial and effective RFP evaluation, the OCC, AG and IM will oversee the opening of all Proposals.

All Proposals must be submitted in accordance with the instructions and on the form(s) provided in the RFP Response Package. All Proposals must include three bound paper copies of the Proposal, with one bearing original signature(s), as well as two CD-ROM's containing electronic copies which must be submitted with all text portions of the Proposal in Microsoft® Word and all spreadsheets in Microsoft® Excel.

Faxed Proposals or Proposals submitted via e-mail or the Internet will be considered non-conforming and will be rejected.

Each Proposal must be submitted separately in a sealed package with the following information shown on the exterior of the package:

____
Name of Bidder

Proposals submitted in response to this RFP will not be returned to Bidders. At the conclusion of the RFP, all Proposals will be archived by OG&E until at least the conclusion of the RFP process and of any other related regulatory review and approval periods.

SECTION 4 - PROPOSAL EVALUATION

4.1 Receipt and Opening of Proposals

The OCC, AG, IM and OG&E's Designated Representative will document and monitor the process of opening all Proposals, including the order in which they are opened, and will ensure that all Proposal documents are housed in a secure location that is accessible only to designated RFP evaluation team members, the OCC, AG and IM.

4.2 Eligibility Requirements

The Company will thoroughly review and assess all Proposals to ensure that each:

(i) is received on time with all forms completed in their entirety;
(ii) is signed by a duly authorized officer or agent of the Bidder;

Proposals that meet these eligibility requirements of the RFP shall be considered.

Except for Proposals not received on time, Proposals that do not meet the requirements specified in this document, may in OG&E's judgment and discretion, be given three business days to remedy their non-conformity.

OG&E reserves the right to contact Bidder(s) to clarify Proposal terms or to request additional information.

4.3 Description of the Evaluation Process

The Company will use a multi-stage evaluation process to review Proposals and to select the preferred resources or portfolio of resources. To proceed through each stage of the evaluation process, a Proposal must meet certain threshold requirements and criteria relative to other Proposals.

The exact evaluation process followed will depend upon the number of Proposals received and changes in economic conditions that may have occurred from the time the Proposals were submitted until the particular stage of the evaluation. For example, while OG&E prefers to conduct a price, other economic and non-price evaluation of all Proposals based on a 60/20/20 weighting between price, other economic and non-price factors, if a large number of Proposals are received, OG&E may conduct an initial price screen prior to the non-price evaluation. Each phase of the evaluation process is described in more detail in subsequent sections.

Each of the price, other economic and non-price characteristics of the Proposals will be evaluated by the Company. Proposals will be evaluated relative to one another and relative to their impact on OG&E's system. The objective of the evaluation process is to select the Proposal(s) that provides the highest value consistent with OG&E's stated objectives and requirements. The preferred Proposal(s) does not necessarily have to be the lowest cost option(s) or highest scoring Proposal(s) from a price and non-price perspective. OG&E is interested in Proposals which provide the most desirable combination of operational flexibility, reliability, risk exposure and low cost.

4.3.1 Eligibility Requirements and Threshold Requirements Screening

The first step in the evaluation process will be to review each Proposal to ensure that it satisfies all of the applicable Eligibility Requirements specified in Section 4.2 of this RFP and Threshold Requirements specified in Section 4.4 of this RFP. In this stage of the evaluation OG&E will determine whether the Proposal meets the Eligibility Requirements specified, the Proposal is consistent with all requirements outlined in the RFP and the Response Package and the Proposal conforms to the Threshold Requirements.

Proposals that provide inaccurate or incomplete information may be rejected. The Company may, in its discretion, provide Bidders the opportunity to correct or clarify their Proposals provided the competitive position of Proposals is not affected. If the Company seeks clarification, Bidders will be given three business days, (or as otherwise stated by the Company in its request), to clarify their Proposal. Proposals that pass this initial screen will proceed to the next stage of the evaluation.

4.3.2 Evaluation Analysis

The next step of the evaluation process will include a price, other economic and non-price evaluation for all Base Proposals that pass the Eligibility and Threshold Screening. The result of the 60/20/20 weighted price, other economic and non-price analysis will be a relative ranking and scoring of the Proposals. Proposals of the same type of contract and contract term will be evaluated relative to similar Proposals at this stage of the evaluation.

The Company may, in its discretion, use screening curves and/or detailed production cost analysis to calculate the total cost impacts of each Proposal on OG&E's system. Proposals will be assigned price rankings based on their impact on OG&E's total system cost. Each Proposal will be evaluated using the price factors contained in the Proposal.

Where appropriate, generation expansion and production cost models will be used to determine and evaluate the impact on the Company's net present worth of the revenue requirement.

4.3.3 Portfolio Evaluation

In this stage of the evaluation process short-listed Proposals will be compared and evaluated against each other. The Company will also consider the benefits of flexibility options proposed by the Bidder relative to its Proposal.

In addition, the Company will assess the transmission impact of each Proposal to determine what, if any, transmission system improvements must be made and the estimated cost of those improvements. The Company will assess the Proposal's transmission system impact using SPP's reliability criteria and the SPP study methodology. Final transmission system impacts and related costs will be determined by the SPP in accordance with the SPP OATT and will be borne by the Company. The Company reserves the right to reject any proposal on the basis of those costs.

In this phase of the evaluation, the Company will conduct sensitivity analysis of important price and economic assumptions to determine how robust the various are to various assumptions. The Company may develop high and low fuel price cases as part of this portfolio evaluation process. Other sensitivities will include economic and environmental factors.

4.4 Threshold Requirements

4.4.1 Credit Threshold

Each Bidder must complete and submit with their Proposal the Bidder Profile Form (Appendix B).

4.5. Description of Price Related Evaluation Criteria

All Proposals will be evaluated on the basis of price and operational performance factors in the price and portfolio evaluation through the simulation of the impact of the Proposal on the overall costs to the OG&E system. Company will consider the impacts of each Proposal on OG&E and its customers. Company will also include other criteria in its analysis, including operational characteristics and flexibility provisions that allow Company to minimize risk and uncertainty. Company's objective in selecting resources, therefore, involves a combination of rate implications and risk minimization options to arrive at the preferred portfolio of resources.

Company proposes to conduct a detailed cost analysis that incorporates all of the costs attributed to each Proposal including, but not limited to:

- Capacity Charge
- Fixed O&M Charge
- Energy Charge
- Fuel transportation Charge
- Variable O&M Charge
- Start-Up Charge
- Emissions Charge
- Ancillary Services Charge
- Transmission System Impact
- Debt Equivalence

A description of each component is presented below.

4.5.1 Capacity Charge

The Capacity Charge reflects the payment that Company will make to the Bidder for having the generating capacity available to Company to operate at the proposed committed capacity level. All Proposals will be evaluated at the target equivalent availability specified by the Bidder unless the target equivalent availability is deemed to be unrealistic for the proposed technology or facility design. Bidders may propose a fixed price for each month or year of the term or a fixed escalation Capacity Charge arrangement at the time of Proposal submission that locks in the Capacity Charge for the term of the PPA. Bidders are prohibited from submitting a Proposal capacity price that includes escalation provisions tied to a variable and uncertain index (e.g., inflation, interest rates, etc.).

The Bidder will be paid Capacity Charges based on the product of the Capacity Charge, Contract Capacity, an allocation factor for the applicable month of the year and the availability adjustment specified in the RFP and PPA.

4.5.2 Fixed O&M Charge

The Fixed O&M Charge reflects the payments that Company would make to the Bidder to cover any Fixed O&M costs associated with their Proposal. This may include such items as fixed labor or staff expenses, property taxes, insurance, fixed maintenance expenses and other fixed operating expenses. Fixed natural gas pipeline and other fuel transportation charges, such as demand charges, should be reflected as a separate Fixed Fuel Transportation Charge. These payments will be calculated based on the initial base period charge and the escalation rate selected by the Bidder.

As noted in the Model PPA, the Bidder will be paid Fixed O&M Charge based on the product of the Fixed O&M Charge, Contract Capacity, an allocation factor for the applicable month of the year and the availability adjustment specified in the RFP and PPA.

4.5.3 Energy Charge

This factor will account for the amount and cost of energy delivered by the Bidder. Such an analysis requires the incorporation of operating characteristics that influence the performance of the subject generation facilities. This includes the level of dispatchability proposed, the level of availability, and other operational constraints.

4.5.4 Fuel Transportation Charge

This Factor will account for the fixed and variable charges for recovery of Bidders fuel transportation cost. Fixed fuel charges, such as demand charges or reservation payments, should be recovered through a Fixed Fuel Transportation Charge.

The Bidder will be paid Fuel Transportation Charges subject to the adjustment for the applicable month of the year and the ration of actual availability to target availability within the perimeters in the RFP and PPA.

4.5.5 Variable O&M Charge

The Variable O&M Charge reflects the payments that Company would make to the Bidder to cover the Variable O&M costs associated with their Proposal. The Variable O&M Charge may take into consideration non-fuel variable expenses related to operation of the Bidders generation facility. Variable natural gas pipeline and other fuel transportation charges, such as transportation charges for natural gas actually delivered, should be reflected as a separate Variable Fuel Transportation Charge. These payments will be calculated based on the initial base period charge and the escalation indices selected by the Bidder.

4.5.6 Start-Up Charge

The Start-Up Charge reflects the payments Company will make each time a generation facility, which specifies such payments, successfully starts its generating facility when called upon by Company to operate. Costs to start-up the generation facility after planned and unplanned maintenance or forced outages will not be included as Start-Up Charges. Company will estimate how many times it expects the generation facility to be required to start-up, and will include the proposed Start-Up Charge in conducting the evaluation. Bidders are encouraged to describe any constraints or unique characteristics of their Proposals which could influence the Company's analysis.

4.5.7 Emissions Charges

Company will evaluate the implications of a Proposal on overall system emission levels to assess how it will impact Company's Emission Allowances and the impact it will have on Company's position in the emission allowance market and any costs or savings associated with a particular Proposal. Company will estimate the SO2, NOx, and mercury emissions from its system as a result of each Proposal. To estimate the impacts associated with each Proposal, Company will calculate the dollar impacts as the net emission impacts of the project times the estimated market value of the emission over the term of the PPA.

4.5.8 Ancillary Services Charge

Ancillary Services that may be provided by generators are:

- Reactive Supply and Voltage Control
- Regulation and Frequency Response
- Load Following
- Energy Imbalance
- Operating Reserves – Spinning
- Operating Reserves – Supplemental
- Black Start

Bidder shall identify in their Proposal any explicit ancillary service charges related to delivering power and energy to Company under their Proposal. In addition, Bidder needs to describe in detail the relationship between Bidder's Proposal generation facility, Company and SPP RTO market operations. The details shall include responsibilities associated with scheduling, asset registration, resource bidding and ancillary service provision.

4.5.9 Transmission System Impact

This criterion considers the upgrades and attendant costs that may be required to OG&E's

transmission system. Company will use its computer modeling capability (e.g., power flow program) to verify and quantify the transmission system impacts, based on the specific data contained in Bidder's Proposal.

4.5.10 Debt Equivalence

Evaluation of PPA Proposals will include the imputed cost (revenue requirement) for any additional common equity required to maintain the Company's current debt-equity ratio. Should the PPA be determined to be treated as a capital lease under EITF 01-08 and SFAS 13, equity will be assumed to be added to maintain the current total debt to equity ratio based on the amount of the debt or capital lease liability anticipated to consolidate onto the Company's balance sheet. Should the PPA be determined to be treated as an operating lease under EITF 01-08 and SFAS 13, equity will be assumed to be added to maintain the current total debt to equity ratio using Standard and Poor's (S&P) published guidelines as a basis of the equity imputation and its cost. Key parameters for the calculations will include ROE (pre-tax) based on the Company's authorized return and net present value ("NPV") discount factor and debt cost at the Company's weighted average cost of debt. If the PPA is not a lease, sensitivities will be calculated at a 30% and a 50% risk factor that will be applied to the fixed charge NPV to calculate the imputed debt. The cost of additional equity will be included as part of the revenue requirement to all applicable PPA Proposals.

As stated in the Threshold Requirements, the Company will not accept any Proposals with contract terms that would require balance sheet consolidation of a Variable Interest Entity ("VIE") per FASB Interpretation No. 46R. Through information gathered from Bidders, the Company will determine whether it will be subject to VIE consolidation treatment at any time during the contract period. Failure in this provision will be considered a disqualification of Proposal.

4.6 Description of Other Economic and Non-Price Related Evaluation Criteria

As noted, Company anticipates that all Proposals will be evaluated relative to other *economic and non-price and risk related criteria deemed to be important to Company*. The Company is interested in PPA Proposals that offer operating flexibility and diversity and are likely to operate consistent with PPA requirements throughout the term of the PPA.

Table 4.1 lists each of the Project other economic and non-price and/or risk-related criteria.

Table 4.1

Other Economic Criteria

Criterion	**Weighting For PPA***
SPP/RTO Markets	45%
Fuel Supply and Transportation Arrangements	45%
Environmental Compliance and Impact	10%

Non-Price Criteria

Criterion	**Weighting For PPA****
Model Contracts	20%
Quality of Output	80%
(i) Dispatchability/Scheduling	
(ii) Coordination of Maintenance	
(iii) Operating Profile/Characteristics	

* Represents the major non-price criteria category weightings which combined represent 20% of the overall price and non-price score.

** Represents the major non-price criteria category weightings which combined represent 20% of the overall price and non-price score.

A detailed list and description of each other economic and non-price criteria for Proposals and Company's objectives relative to such criteria follows.

- Execute one or more definitive agreements with any Bidder that submits a proposal or with any other person or with no one.

If at any time the Company determines that there is a defect in the RFP process or a deviation from the requirements of the RFP or that collusive or fraudulent bidding has occurred or appears to have occurred, the Company, in consultation with the OCC, AG and IM, may suspend the RFP in whole or in part as to any Bidder or Bidders so involved.

Under all circumstances, each Bidder is responsible for all costs and expenses it incurs in connection with the RFP. Under no circumstances, including the Company's termination of the RFP at any time, will the Company or any of its representatives be responsible for any costs or expenses of any Bidder incurred in connection with the RFP.

SECTION 7– GLOSSARY OF TERMS

1 Affiliate: Is any person directly or indirectly controlling or controlled by or under direct or indirect common control with such person or any person that directly or indirectly (through one or more intermediaries) controls or is controlled by or is under common control with the person. For purposes of this definition, "control" (including, with correlative meanings, the terms "controlling," "controlled by" and "under common control with"), as used with respect to any person, shall mean the direct or indirect ownership or control of, or the possession, directly or indirectly, of the power to vote, five percent (5%) or more of the outstanding voting securities of such person, or the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such person, whether through the ownership of voting securities, by agreement, or otherwise.

2. Balancing Authority Area: The collection of transmission, generation and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load resource balance within this area.

3. Commercial Operation Date: The date upon which the seller's delivery obligations commence under a PPA.

4. SPP RTO: The Southwest Power Pool Regional Transmission Organization. Major services provided by the SPP RTO to members include independent reliability coordination and tariff administration, regional engineering model development, planning and operating studies, reliability assessment studies, a computer-based telecommunications network, and operating reserve sharing. SPP provides regional transaction scheduling and is in the process of implementing market settlement functionality as required by FERC Order 2000.

Appendix A

MUTUAL CONFIDENTIALITY AGREEMENT

This Mutual Confidentiality Agreement ("Agreement") dated as of __________, 2006 ("*Effective Date*") *is made and entered into by and between* Oklahoma Gas and Electric Company, an Oklahoma corporation ("OG&E") and *insert full legal name*, a(n) *insert state of formation insert type of company* ("Bidder").

Recitals:

I. Bidder may submit or has submitted a "Proposal" in response to a Request for Proposals (the "RFP") for [*insert amount of Proposal in MW*] of [*insert type of product, e.g., firm energy or capacity with firm energy*] issued by OG&E. The Proposal shall be held confidential under terms of the RFP.

II. It may become desirable that OG&E and Bidder exchange other confidential information pursuant as part of the RFP process including questions, responses or other communications that are not contained in the Proposal and which the parties desire to protect as confidential.

III. In addition, if the Proposal is selected for the Award Group Selection (as defined in the RFP), then Bidder and OG&E anticipate entering into negotiations concerning definitive agreements to implement the Proposal (the "Definitive Agreements"). Bidder and OG&E want to keep all negotiations

concerning the Definitive Agreements, including the Definitive Agreements and all drafts of the Definitive Agreements, confidential.

IV. The parties are willing to exchange such confidential information pursuant to the terms of this Agreement.

NOW, THEREFORE, *in consideration of the mutual covenants contained herein*, the parties agree as follows:

1. **Definitions**.

As used in this Agreement, the term "**Confidential Information**" means all information, data and experience, whether of a legal, technical, business, engineering, operational or economic nature, not generally known to the public, proprietary in nature, or which would constitute a trade secret under the U.S. Uniform Trade Secrets Act, which is used, developed, or obtained pursuant to this Agreement and or supplied to or obtained by Recipient from Disclosing Party relating to business and/or research and development efforts, including without limitation, research, results of research, findings, products, proposals, formulas, test results, product development, discoveries, processes, designs, drawings, engineering studies, marketing reports, financial information, technical information, know-how, technology, prototypes, ideas, inventions, improvements, data, files, information relating to the supplier and customer identities and lists, accounting records, business and marketing plans, marketing reports, method of doing business, and all similar information, and all copies and tangible embodiments thereof (in whatever form or medium). Confidential Information may be either the property of Disclosing Party or information provided to Disclosing Party by a corporate affiliate of Disclosing Party or by a third party.

As used in this Agreement, the term "**Recipient**" shall include each Recipient, representatives and employees of each Recipient, and all affiliates, subsidiaries, and related companies of each Recipient.

As used in this Agreement, the term "**Employees**" includes third parties retained for professional advice (including, without limitation, attorneys, accountants, consultants, bankers, and financial advisors) and for temporary administrative, clerical, or programming support.

As used in this Agreement, the term "**Need to Know**" means that the Confidential Information is essential for each Recipient or Employee to perform his or her responsibilities in connection with the purposes of this Agreement.

2. <u>Exclusions</u>.

Confidential Information does not include information that: (a) is or becomes available to the public through no breach of this Agreement; (b) was previously known by either Recipient without any obligation to hold it in confidence; (c) is received from a third party free to disclose such information without restriction; (d) is independently developed by either Recipient without use of Confidential Information of Disclosing Party; (e) is approved for release by written authorization of either Disclosing Party, but only to the extent of and subject to such conditions as may be imposed in such written authorizations; (f) is required by law or regulation to be disclosed, but only to the extent and for the purposes of such required disclosure as determined by an opinion of counsel; or (g) is disclosed in response to a valid order of a court or other governmental body of the United States or any of its political subdivisions, but only to the extent of and for the purposes of such order; provided, however, that each Recipient will first notify Disclosing Party of the order and permit Disclosing Party to seek a protective order or other appropriate remedy and/or waive compliance with the provisions of this Agreement.

3. <u>Recipient's Obligations</u>.

A. Each Recipient agrees that the Confidential Information is to be considered confidential and proprietary to Disclosing Party, and each Recipient shall hold, maintain and treat the same in confidence and trust, shall not disclose to any unauthorized entity or person, and shall not use the Confidential Information for any unauthorized purpose. The Confidential Information can and will only be used for the purposes of the business, potential business discussions, and authorized purposes between each Disclosing Party and Recipient. The Confidential Information shall only be disclosed to each Recipient's officers, directors, or employees with a specific need to know. Each Recipient will advise those employees who gain access to Confidential Information of their obligations regarding the Confidential Information, and each such employee shall sign the attached form of acknowledgement agreeing to be bound by this Confidentiality Agreement and all its terms. Each Recipient will not disclose, publish, or otherwise reveal any of the

Confidential Information received from Disclosing Party to any other party whatsoever except with the specific prior written authorization of Disclosing Party.

B. Confidential Information furnished in tangible form shall not be duplicated by either Recipient except for purposes of this Agreement. Each Recipient shall, within twenty (20) days of a written request by Disclosing Party, return all Confidential Information received in written or tangible form, including copies, or reproductions or other media containing such Confidential Information, or, if so directed by Disclosing Party, destroy all such Confidential Information. Recipient shall also, within ten (10) days thereafter, certify in writing that it has satisfied all obligations with respect to destruction.

4. Construction.

This Agreement shall be construed and governed by the laws of the State of Oklahoma. The prevailing party in any dispute to enforce this Agreement shall be entitled to recover from the losing party its costs and a reasonable attorney's fee to be determined by the court.

5. Ownership of Confidential Information.

Except as otherwise provided in the RFP, all Confidential Information (including copies thereof) shall remain the property of the Party so disclosing, and shall be returned to that Disclosing Party after the Recipient's need for it has expired, or upon the request of that Disclosing Party, and in any event, upon termination of this Agreement.

6. Term and Termination.

If the Bidder's Proposal and/or related negotiations do not result in a final agreement, then this Agreement is effective for two (2) years from the Effective Date stated above. If the negotiations result in the execution of Definitive Agreements, then this Agreement is effective until one (1) year after the termination of the Definitive Agreements.

7. No License or Warranty.

Nothing contained herein shall be construed as granting or conferring any patent, copyright, trademark, or other proprietary rights, by license or otherwise, in any Confidential Information disclosed hereunder. No warranties of any kind are given for the Confidential Information disclosed under this Agreement.

8. Governing Law and Equitable Relief.

This Agreement shall be governed and construed in accordance with the laws of the State of Oklahoma, and each Recipient consents to the exclusive jurisdiction of the state courts located therein for any dispute arising out of this Agreement. Both parties agree that an impending or existing violation of any provision of this Agreement would cause such Disclosing Party irreparable injury for which it would have no adequate remedy at law, and that such Disclosing Party will be entitled to seek immediate injunctive relief prohibiting such violation without the posting of bond or other security, and/or seek specific performance of Recipient's obligations under this Agreement. Such rights of each Disclosing Party are to be in addition to any remedies otherwise available to Disclosing Party at law or in equity.

9. Relationship of Parties.

Neither party shall have any obligation to commence or continue discussions or negotiations, to exchange any Confidential Information, to reach or execute any agreement with the other party, to refrain from engaging at any time in any business whatsoever, or to refrain from entering into or continuing any discussions, negotiations or agreements at any time with any third party, until each party executes a definitive agreement. Until such definitive agreement is executed, neither party shall have any liability to the other party with respect to the Transaction except as set forth in this Agreement. Neither party shall have any liability to the other party in the event that, for any reason whatsoever, no such definitive agreement is executed.

10. Final Agreement.

This Agreement terminates and supersedes all prior understandings or agreements on the subject matter hereof. This Agreement may not be modified, amended, or waived, except by a written instrument duly executed by both parties.

11. No Assignment.

This Agreement shall not be assigned by either party without the prior written consent of the other. Any assignment in violation of this Section will be void. This Agreement will be binding upon the parties and their respective successors and assigns.

12. Severability.

If any provision of this Agreement is held by a court of competent jurisdiction to be invalid or unenforceable, such provision will be deemed deleted from this Agreement. The Agreement, including all of the remaining terms, will remain in full force and effect as if such invalid or unenforceable term had never been included.

13. No Implied Waiver.

Either party's failure to insist in any one or more instances upon strict performance by the other party of any of the terms of this Agreement shall not be construed as a waiver of any continuing or subsequent failure to perform or delay in performance of any term hereof.

14. Authority.

Each party warrants that it has the authority to enter into this Agreement and to lawfully make the disclosures and other obligations contemplated hereunder.

15. Headings.

Headings used in this Agreement are provided for convenience only and shall not be used to construe meaning or intent.

16. Attachments

____________________(number of) employee acknowledgement forms are attached to and incorporated by reference to this Agreement as required under paragraph 3.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first above written.

OGE ENERGY CORP.	COMPANY NAME (OUTSIDE PARTY)
Name: ______________________	Name: ______________________
Title: Type VP's name and Title	Title: ______________________
Date: ______________________	Date: ______________________

ACKNOWLEDGEMENT
OF
CONFIDENTIALITY AGREEMENT

I, the undersigned, do hereby acknowledge that I have read and fully understand the accompanying Confidentiality Agreement dated ________________ between OGE, its subsidiaries and affiliates, and ____________________ for the purpose of ______________________ (stated purpose or name of Main Agreement with date just like set forth in confidentiality Agreement) and do further consent to be bound by its terms and conditions.

____
Printed Name

____
Title

____
Signature

____

____
Date

SUBSCRIBED AND SWORN TO before me on this ______day of _________, 200__.

____
NOTARY PUBLIC

My Commission Expires:______________

Commission Number: _________________

[SEAL]

Appendix B

Please submit the following information for the Applicant:

1) Three most recent Annual Reports, if available;
2) Three most recent SEC Form 10-K; if unavailable, please provide three years of most recent audited financial information, which include Balance Sheet, Income Statement, Cash Flow Statement and accompanying related Notes.
3) Most recent SEC Form 10-Q; if unavailable, most recent audited quarterly financial information, including Balance Sheet, Income Statement, Cash Flow Statement and accompanying related Notes. If audited quarterly information is unavailable, provide most recent quarterly or monthly financial data accompanied by an attestation by the Applicant's Chief Financial Officer that the information submitted is a true, accurate, and fair representation of the Applicant's financial condition;
4) Applicant's Senior Unsecured Credit rating from the following agencies:

   Standard & Poor's   Moody's Investor Service

5) If Senior Unsecured Credit Ratings are unavailable, provide the Applicant's corporate issuer ratings from the following agencies:

   Standard & Poor's   Moody's Investor Service

Please provide the Applicant's Tangible Net Worth as of the last audited fiscal year end.

Applicant's TNW

Is the Applicant:

1) Operating under Federal Bankruptcy laws or bankruptcy laws in any other jurisdiction? (Y/N)

   Applicant

2) Subject to pending litigation or regulatory proceedings (in state court, federal court, or from regulatory agencies, or in any other jurisdiction) which could have a material impact on the Applicant's financial condition? (Y/N)

   Applicant

3) Subject to collection lawsuits or outstanding judgments, which could impact solvency? (Y/N)

Applicant

Please provide a statement disclosing any existing, pending, or past adverse rulings, judgments, litigation, contingent liabilities, revocations of authority, administrative, regulatory (State, FERC, SEC, DOJ, or other) investigations and any other matters relating to financial or operational status for the past three years that arise from the sale of electricity or natural gas, or materially affect current financial or operational status.

Appendix C

Model Purchase Power Agreement

OKLAHOMA GAS AND ELECTRIC COMPANY
FIRM ENERGY OR CAPACITY WITH FIRM ENERGY
YEARS 2008 – 2010

Buyer: Oklahoma Gas and Electric Company (OGE)

Product: Unit Commitment (WSPP Schedule B) or System Firm (WSPP Schedule C). OGE encourages the Bidders to supply offers from, or modeled on, peaking, intermediate and base-load generation resources.

Contract Quantity: ______________MW

Governing Agreement: WSPP, EEI.

Term: Periods beginning ___________ through and including___________.

Delivery Point: At the Seller's busbar (if the generation source is located within the OG&E Control Area (or Balancing Authority Area) or into the OG&E Control Area (if the generation source is not located within the OG&E Control Area).

Transmission: This transaction shall be contingent upon the Seller obtaining firm point-to-point or network transmission service for the Contract Quantity and Term. The Buyer shall be responsible for all transmission services and cost beyond the delivery point. If sourced from within the OG&E Control Area, OG&E may commit to designating the source as a network resource; however such commitment is contingent upon Buyer's sole discretion regarding the cost of any transmission upgrade which may be required by the SPP as a result of its study in connection with such designation.

Capacity Price: Submit price in $/kw/mo for the proposed term.

Energy Price: Must be in the form of the sum of a Variable O&M Charge plus an Identifiable Fuel Charge (in $/MWh). The Identifiable Fuel Charge must relate to either A) actual costs of fuel (coal, natural gas, etc.) whether supplied by OGE or the Seller, or B) a Fuel Index multiplied by a Heat Rate of the generation resource. The Fuel Index can be set monthly or daily, or a combination thereof and can based on coal, natural gas, #2 fuel oil, or other readily available fuel index of sufficient liquidity.

Scheduling: OGE encourages bidders to provide flexible scheduling provisions. OGE will evaluate, must-take energy provisions, day-ahead or intra day scheduling notification for 16-hour on-peak blocks, shaped schedules, minimum daily/hourly schedule amounts, etc.

Scheduling practices shall comply with the policies of the North American Electric Reliability Council's policies and the applicable open access transmission tariff, as it may be amended or superseded from time to time.

Miscellaneous: Preference will be given to the Bidder that supplies the lowest <u>overall</u> cost as evaluated by OGE.

Comments: This draft term sheet is intended to be used for discussion purposes only. Energy anticipated under these terms is subject to management approvals by both parties, the availability of transmission capacity for the amounts contemplated herein, and the approvals or review of any regulatory entity having such authority over of the term and conditions of this RFP, including specifically the Oklahoma Corporation Commission and/or the Southwest Power Pool. This draft term sheet is not to be construed as a complete integration of any agreement and does not constitute a binding agreement by either party. This document expresses a good faith intention to proceed with discussions and investigation of possible business arrangements between both parties .Oklahoma Gas and Electric Company reserves the right to reject any and all proposals for any reason.

Appendix E – Transmission System Analysis for New Generation Resources

Remainder of Appendix E Redacted
HIGHLY SENSITIVE CONFIDENTIAL INFORMATION

Appendix F – Description of CERA Scenarios

This appendix contains CERA's *2005 North American Gas and Power Scenarios* as published in March 2006.

Remainder of Appendix F Redacted
HIGHLY SENSITIVE CONFIDENTIAL INFORMATION

Appendix G – Economic Input Data

This appendix presents the economic input data used to evaluate alternatives for this IRP. The economic input data are presented in Table G-1 below.

Parameter	Value
Regulatory Capital Structure:	
Long-Term Debt	44.31%
Common Equity	55.69%
Allowed Returns:	
Long-Term Debt	6.03%
Common Equity	10.75%
New Project Long-Term Debt Interest Rate	7.00%
Combined Income Tax Rate	38.70%
Annual Inflation Rate (2007 – 2036)	2.50%

Table G-1 Economic Input Data

Appendix H – Generation Technology Assessment

This appendix contains the Generation Technology Assessment (February 2006) prepared by Burns & McDonnell on the behalf of OG&E.

Remainder of Appendix H Redacted
HIGHLY SENSITIVE CONFIDENTIAL INFORMATION

Appendix I – CEM Description and Input Data

This appendix describes Global Energy's CEM application and presents the input data used to evaluate alternatives for this resource plan.

A. Description and Usage

The Global Energy's CEM is a mid- to long-term company portfolio capacity optimization model for automated screening and evaluation of decisions for generation capacity expansion and retirement options, contract transactions, and transmission capacity expansion. The model creates generation portfolios for the various possible futures based on the minimum NPVRR while maintaining a minimum 12% planning reserve margin.

OG&E uses CEM as a screening model to evaluate long-term expansion decisions for alternate growth and supply scenarios and to develop preferred expansion portfolios that perform well in various scenarios. Despite the considerable advantages of using the CEM for resource capacity planning, it is only intended for use as a preliminary screening tool for quickly and objectively narrowing the choice set from an extremely large number of possible resource plans down to a few "good" alternatives for more detailed final screening using simulation analysis with PAR.

B. Optimization Algorithm

The model is a mixed integer linear program (MILP) in which the objective is minimization of the sum of the discounted costs of supplying customer loads. This objective definition is termed the NPVRR. The model includes all existing and proposed plants and transmission upgrades in the system. Binary integer variables are used in the MILP to represent discrete decisions regarding whether to build or retire generation at a particular site or enter into a particular contract transaction. General integer variables are used to represent how many discrete units of generation capacity to add at the sites.

In any project that involves substantial, up-front commitments of capital, such as the purchase of a large facility or plant, project economics are driven to a large extent by how the project recovers the cost of the initial capital outlay. When the study period is less than the resource life span, the model needs to capture the profit or loss and investment recovery for the remaining life span outside of the study period. The impact of the profit or loss and investment recovery in the time period outside of the study period is called the "end effect." The end effects bias is most pronounced for selection of capacity needed in the final years before the study horizon. The end effects bias is mainly caused when one project is more capital intensive than another, or has a longer service life than another. Both of these factors cause the more capital-intensive or longer-lived project to have higher initial capital cost, while some or most of its operating cost savings over the alternative project are not realized until after the study horizon.

To minimize the end effects bias, CEM uses annual capital recovery factors only for the years during which the selected project provides generation or transmission services. That is, only a portion of lifetime capital recovery costs are included in the model's objective function if the asset's service life (and amortization period) is longer than the duration of providing services until the study horizon date.

Capital recovery factors eliminate the need for residual value accounting or the use of "extension years" to measure the full life-cycle operating cost savings of capital-intensive investments.

Capital recovery costs may be constant, rising, or falling over the amortization period. Actual capital recovery costs generally decline through time, resulting from nominal level debt service costs and tax depreciation accounting. But for capital investment selection purposes, nominal levelized or real levelized capital recovery assumptions are generally used. The real levelized method is superior from the standpoint of minimizing end effects bias created when projects have service lives longer than their simulated service period within the study period. The real levelized amortization method is also referred to as the "real economic carrying cost" (RECC) method.

The first year capital recovery factor (CRF_1) for the real levelized method is defined as:

$$CRF_1 = \frac{(d-g)(1+d)^n}{(1+d)^n - (1+g)^n}$$

where:

d = nominal discount rate,
g = growth (inflation) rate, and
n = lifetime of investment.

For the n-1 following years, the nominal capital recovery factor grows at the rate of inflation.

$$CRF_n = CRF_1(1+g)^{n-1}$$

The above formula for calculating capital recovery factors that escalate over time simplifies to the standard capital recovery factor formula used for nominal levelized capital charges, when the growth rate (g) is set to zero.

$$CRF = \frac{d(1+d)^n}{(1+d)^n - 1}$$

C. Input Data

The following tables are included in this appendix:

- Table I-1 Existing Unit Characteristics
- Table I-2 New Unit Characteristics
- Table I-3 Variable Unit Parameters – Cost Data

- Table I-4 Variable Unit Parameters – AES Shady Point Maintenance Rates
- Table I-5 Variable Unit Parameters – Horseshoe Lake Maintenance Rates
- Table I-6 Variable Unit Parameters – McClain Maintenance Rates
- Table I-7 Variable Unit Parameters – Muskogee Maintenance Rates
- Table I-8 Variable Unit Parameters – Mustang Maintenance Rates
- Table I-9 Variable Unit Parameters – PowerSmith and Pryor Maintenance Rates
- Table I-10 Variable Unit Parameters – Seminole Maintenance Rates
- Table I-11 Variable Unit Parameters – Sooner Maintenance Rates
- Table I-12 Variable Unit Parameters – Tinker and Woodward Maintenance Rates
- Table I-13 Coal Prices (2007 – 2016)
- Table I-14 Natural Gas Prices by Scenario (2007 – 2016)
- Table I-15 Emissions Costs by Scenario (2007 – 2016)

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Appendix J – PAR Input Data

This appendix presents the input data used in Global Energy's PAR application to evaluate alternatives for this resource plan. The following tables are included in this appendix:

- Table J-1 Generating Capacity Data
- Table J-2 Average Heat Rate Data
- Table J-3 Heat Input Rate Curve Data
- Table J-4 Startup Fuel Data
- Table J-5 Minimum Up and Down Times Data
- Table J-6 Commit / Dispatch Status Data
- Table J-7 Commit Status Data (PowerSmith)
- Table J-8 Outage Rate Data
- Table J-9 Maintenance Weeks Data – Existing Non-Coal Units (2007 – 2016)
- Table J-10 Maintenance Days Data – Existing Coal Units (2007 – 2016)
- Table J-11 Maintenance Rates Data (%/yr) – New Units and Existing Wind / DSM
- Table J-12 Emission Rates Data
- Table J-13 Variable O&M Cost Data
- Table J-14 Fixed O&M Cost ($/kW-yr) Data
- Table J-15 Fixed O&M Cost ($/yr) Data
- Table J-16 Average Monthly Wind Profile (50 MW @ 36% Capacity Factor)
- Table J-17 Average Monthly Wind Profile (80 MW @ 44% Capacity Factor)
- Table J-18 Average Monthly Wind Profile (120 MW @ 44% Capacity Factor)
- Table J-19 Station Fuel Name Data
- Table J-20 Station Start Fuel Name Data
- Table J-21 Monthly Fuel Price Data (2007 – 2016)
- Table J-22 Fuel Demand Charge Data
- Table J-23 Units in Service by Planning Case (2007 – 2016)

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Appendix K – Ten-Year Transmission Contingency Study

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