Direct Use of Natural Gas

Implications for Power Generation, Energy Efficiency, and Carbon Emissions

April 2008

American Gas Foundation
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1.0 EXECUTIVE SUMMARY

The North American energy market will experience continued uncertainty for the foreseeable future. In spite of notable increases in natural gas prices in recent years, the use of natural gas for power generation in the U.S. is expected to increase significantly in response to efforts to regulate greenhouse gas emissions. Concerns are also heightened regarding availability of energy supplies to meet growing demand. Both trends suggest that any comprehensive approach to addressing our nation's energy needs will include significant new commitments to both increasing energy efficiency and reducing the environmental impacts of energy use.

In addressing the challenge of meeting increasing demand for energy while also reducing greenhouse gas emissions restrictions through 2030, it is clear that a "silver bullet" does not exist. Rather it is prudent for policy makers to consider pursuing a number of alternatives which together yield a practical energy policy that advances energy efficiency and reduces CO_2 emissions while sustaining economic growth. The analysis presented in this report examines the potential for the increased use of natural gas in residential and commercial applications to increase the productivity of available energy supplies, reduce overall energy cost, and reduce related CO_2 emissions.

Purpose and Scope

The analysis summarized in this report examined the impact of the increased direct use of natural gas for Residential & Commercial ("R&C") end uses. End uses considered include space heating, water heating, cooking, and clothes drying. The study analyzes the effect of the increased direct use of natural gas on expected use of gas for electric generation and the net effect in total energy use, energy costs and CO_2 emissions.

Although there are several factors that drive the use of natural gas for power generation, there is a growing concern that the overall natural gas supply/demand balance could be adversely impacted as demand of natural gas for power generation continues to grow. The underlying framework of the study considers the impact of the increased use of natural gas for direct applications in a series of scenarios. This study examines the impact of future scenarios that may influence ongoing policy debate and establishes a quantitative approach that can be replicated or expanded for future analysis.

The scenarios identified key drivers of uncertainty within the natural gas market. The key uncertainties are the natural gas supply, new technology for R&C applications and the environmental regulations related to CO_2 emissions. The combinations of these three variables create five distinct scenarios.

- Reference Case – Baseline Technology/No CO_2 Restrictions
- Natural Gas Supply Lower & High Technology/High CO_2 Restrictions
- Natural Gas Supply Lower & 2006 Technology/High CO_2 Restrictions
- Natural Gas Supply Higher & High Technology/Low CO_2 Restrictions
- Natural Gas Supply Higher & 2006 Technology/Low CO_2 Restrictions

The scenarios employ assumptions regarding supply sensitivities as referenced in the Energy Information Administration's Annual Energy Outlook ("AEO") 2007[1] integrated price cases. The Natural Gas Supply Higher scenario drives lower prices and higher consumption of natural gas relative to the reference case. The Natural Gas Supply Lower scenario drives higher prices and lower consumption. The High Technology and 2006 Technology cases from the Energy Information Administration ("EIA") were incorporated into these two supply environments. Higher Technology refers to high efficiencies of appliances and building shells which lower energy consumption. Conversely, lower technology is linked to increased energy consumption. The effect of technology on energy consumption makes it a key variable for both supply worlds. The Low and High CO_2 restriction scenarios reflect implementation of moderate and stringent controls on CO_2 emissions from the U.S. electric sector. This will increase the use of natural gas fueled generation.

This study examined the impact of increased direct use of natural gas in the context of each scenario by forecasting primary energy consumption, energy costs, and CO_2 emissions with and without an assumed increase in the direct use of natural gas to half the R&C electric loads capable of operating on natural gas but currently powered by electricity. This scenario assumption of increased direct gas use amounts to about 7% of the total R&C electric load in 2030. The study also utilizes three underlying energy metrics that provide a clear measure of each scenario.

- Energy consumption (as measured in Quadrillion Btu)
- Total energy cost (as measured in 2005 dollars)
- CO_2 Emissions (as measured in millions of tons)

Some of the forecasting that was analyzed in this study was based on the AEO 2007. Although the AEO 2008 was released too late to incorporate in this study, B&V has reviewed the early release of the AEO 2008 and has come to the conclusion that, while the forecasts indicate lower natural gas and electric demand, there would still be significant savings in primary energy use, CO_2 emissions and the cost of energy from the increased direct use of natural gas with the use of the updated AEO forecast. The AEO 2008 forecasts a slight reduction in electric load growth from the 2007 forecast amounting to 5% less electric consumption in 2030. The natural gas consumption forecast for 2008 is 10% less in 2030 than the AEO forecast for 2007.

[1] *B&V utilized the high and low integrated price cases from AEO 2007.*

Major Findings

- Increased direct use of natural gas in R&C applications can increase the productivity of available energy supplies, reduce overall energy cost, and reduce related CO_2 emissions in all scenarios considered.

- Natural gas demand for power generation is expected to increase significantly in a CO_2 constrained world. Nuclear power and renewables could offset part of the increase but natural gas demand is still projected to increase over the forecast horizon with an accompanying upward pressure on gas prices.

- The increased direct use of natural gas for R&C applications rather than for power generation is expected to decrease energy consumption in the United States. Within the scenarios considered, a shift of 7% of the total electric load for R&C applications to natural gas, indicates that the energy savings can range from 1.25-2.00 quadrillion Btu in 2030 – or 6% of total energy consumption growth projected by AEO through 2030. In the absence of restrictions on CO_2 emissions, there is a greater proportion of coal fired plants in the electric generation mix. Coal generation gets displaced when the increased direct use of gas for R&C applications decreases electricity demand.

- Depending on the scenario, the avoided generation capacity is forecast to range from 63 to 80 GW. The avoided investment costs are forecast to range from $49 billion to $122 billion.[2]

- With restrictions on the total level of CO_2 emissions, natural gas generation is displaced when the increased direct use of gas for R&C applications decreases electricity demand. A larger market percentage of the direct use of natural gas for R&C applications drives a net decrease in overall gas consumption as well as energy costs (since the decrease in gas demand for power generation is higher than the increase in direct use of natural gas in the R&C sectors).

- In the scenario where CO_2 restrictions match the levels proposed by the Lieberman-Warner Senate bill currently being debated in Congress, the value of the reduction in energy costs is significant and ranges from $18 to almost $29 billion dollars by the year 2030.

- Emissions are decreased in all scenarios considered. The highest impacts are in the Reference Case where coal fired generation is displaced. The CO_2 constrained scenarios also show a decrease in CO_2 emissions when there is a greater direct use of gas in R&C applications.

[2] The estimate of avoided electric generating capacity in GW was based on simplified assumptions of the demand for uses that can be served by natural gas or electricity at the time of peak demand for supplying electric utilities. A detailed analysis of residential and commercial electric load patterns by end use coincident with electric system peaks would be required to better estimate the avoided generation capacity. Such a detailed analysis should be included in subsequent investigations.

- ❖ There are regional implications to CO_2 emissions regulations and the direct use of natural gas for R&C applications rather than for power generation. Some of the states with larger potential for greater direct use of natural gas for R&C uses are also the states applying CO_2 restrictions in advance of any restrictions by the federal government, notably, these include California, Florida and the Northeast states participating in the Regional Greenhouse Gas Initiative ("RGGI"). For these states, the increased use of natural gas by R&C customers stands to reduce overall costs of energy supplies and reduce emissions consistent with state goals. Several measures are being considered to decrease emissions, and the front runners among these are increased end use efficiency, increased nuclear generation and increased use of renewable fuels. However these measures alone are unlikely to reduce CO_2 emissions to the projected targets and a combination of multiple smaller measures are required to approach the CO_2 target.

Summary Results

The analysis assessed the net impact through 2030 of an increase in direct use of natural gas for R&C applications and entailed the following steps in order to examine the impact on the U.S. energy market:

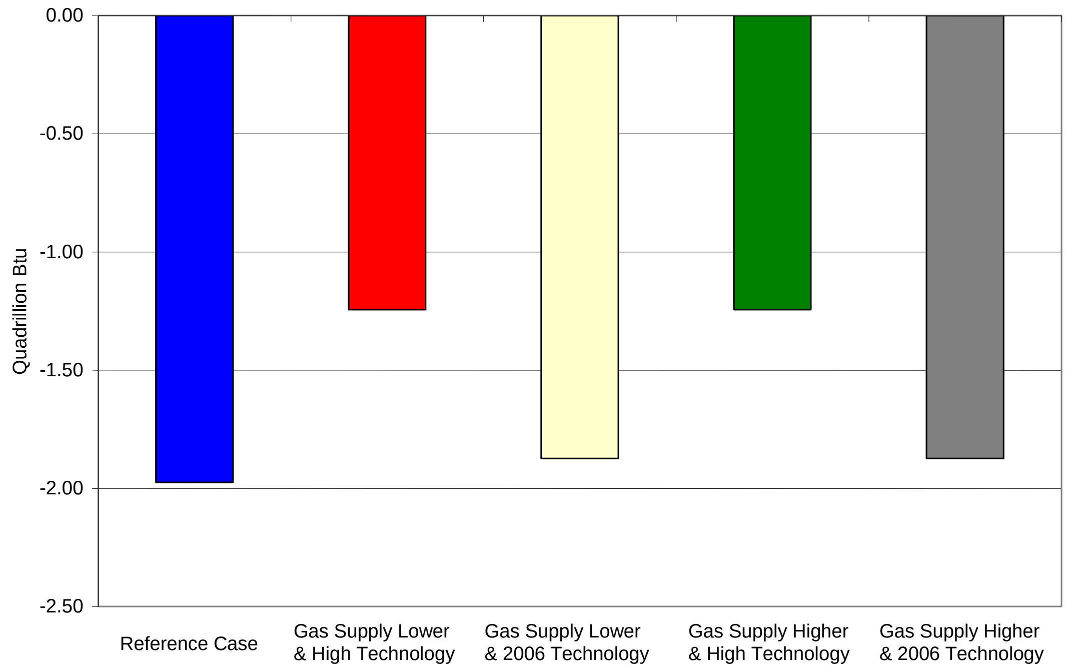
- Forecast the impact of the increased natural gas demand from shifting a percentage of current electric demand for switchable R&C applications to natural gas;

- Forecast the impact of corresponding decreased electricity demand for R&C applications; and

- Estimate the net impact on the energy requirements in the U.S. from a shift in R&C demand from electricity to natural gas.

The net impact on energy consumption from the increased direct use of natural gas for R&C applications instead of for power generation is shown in Figure 1.1. The analysis indicates a net decrease in the total energy consumption in the United States that ranges from 1.25 quadrillion Btu to almost 2 quadrillion Btu in 2030. The greater efficiency of natural gas in the R&C applications when compared to electricity is the contributing factor that drives the expected savings in energy. The "real energy" analysis takes into account the efficiency of the appliance and the overall energy acquisition and delivery process.

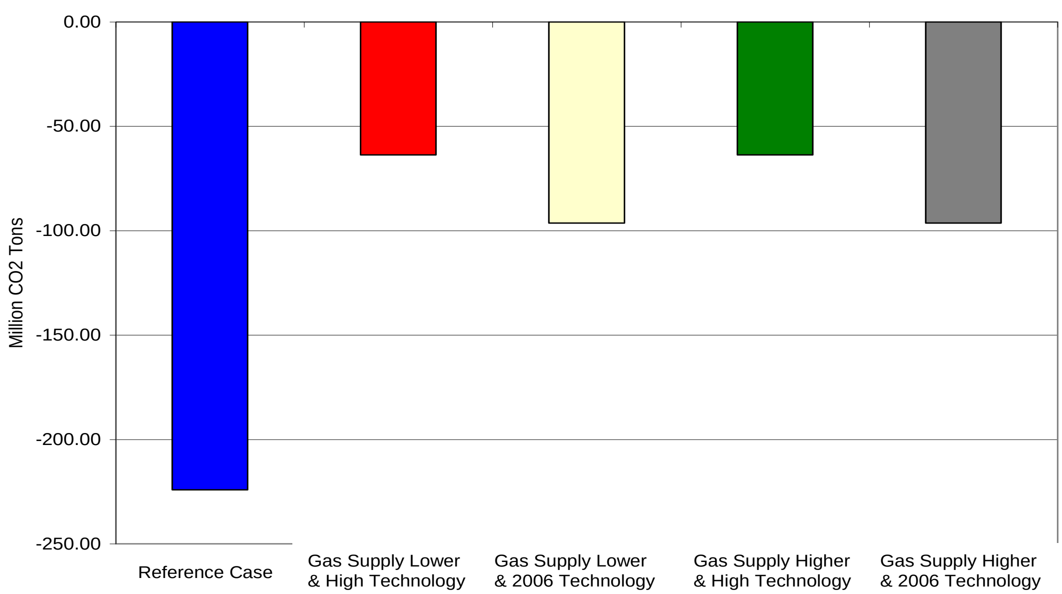
Figure 1.1: Decrease in Energy Consumption in 2030 – Real Energy



Source: EIA, B&V Analysis

The net impact on CO_2 emissions from the increased direct use of natural gas for R&C applications is shown in Figure 1.2. In all the scenarios considered, there is a net decrease in the total CO_2 emissions from the increased use of natural gas for R&C applications. The Reference Case shows the largest decrease in emissions of over 200 million tons of CO_2 driven by a decrease in coal fired generation. The decrease in CO_2 emissions in the other scenarios range from about 60 to almost 100 million tons of CO_2.

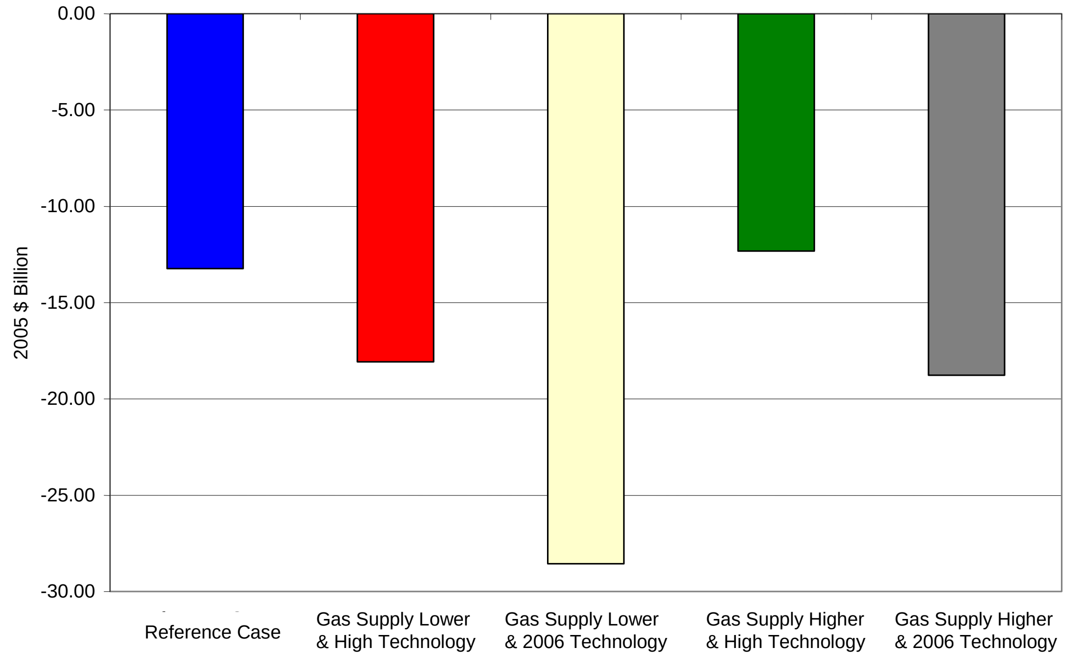
Figure 1.2: Decrease in Emissions in 2030 – Real Energy



Source: EIA, B&V Analysis

The net impact on the total energy costs for the U. S. is shown in Figure 1.3. In all the scenarios considered, there is a net decrease in the total energy costs in 2030. The savings in energy costs range from $12 billion to almost $29 billion in 2030.

Figure 1.3: Decrease in Energy Costs in 2030 – Real Energy



Source: EIA, B&V Analysis

Additional Observations

Expectation of Current Market Conditions for Natural Gas to Continue

Natural gas production in the lower 48, including both onshore and offshore production, is expected to peak in 2017 at 53.4 Bcf/day. With the exception of the Rockies and other unconventional plays, the supply of natural gas in the U.S. is projected to decline. There is an expectation of a flat trend in the domestic supply of natural gas in the U.S. Increased reliance on LNG is projected as imports increase to keep up with growth in the demand for natural gas. Appendix B provides a more detailed overview of natural gas supply in North America. Since the U.S. will be competing with countries that have very aggressive demand projections for natural gas, it is likely that the price of natural gas will continue to be sustained at the current high levels.

Drivers of Natural Gas Demand Remain Strong

Natural gas is a versatile fuel with a number of important characteristics that make it a premium fuel. It is a clean burning fuel with relatively low emissions when compared to coal, petroleum and other fossil fuels. As a fuel with a delivery efficiency amounting to about 90% from production to consumption, it offers an extremely efficient alternative to serve end uses wherever applicable.[3] In contrast, the delivery efficiency for oil is 86% and the delivery efficiency for electricity is 27% as a result of the efficiencies of the source fuels used to generate the electricity as well as the losses during the conversion of the source fuel to electricity and the losses during the transmission of electricity to serve end use markets.[4] The real energy method for measuring efficiency used in this report takes into account these losses as well as the appliance efficiency. Natural gas also offers reliability of supply due to the large proportion that is domestically produced, the underground pipeline network that is not easily affected by weather and other disruptions, and the ability to store the gas and use it when required.

Gas Use for Power Generation is Expected to Increase Significantly

The power generation industry in the U.S. is facing serious uncertainty - maybe more serious than any uncertainty it has faced in the last 25 years. This uncertainty stems from a number of factors, including a national imperative calling for reductions in greenhouse gas emissions that are believed to be a major contributor to global warming. Natural gas demand for power generation is expected to increase significantly in the coming years. Increased end use efficiency, nuclear power and renewables may offset some of the increase, but gas demand for electricity production will increase multiple times before the U.S. gets even close to the CO_2 caps targeted in recently proposed legislation.

CO_2 Emissions Regulations Will Significantly Impact the Natural Gas Market

Emerging trends towards greater energy efficiency as well as a more highlighted focus on the environmental implications of our energy use further support the adoption of measures that would decrease energy consumption and reduce our environmental footprint. CO_2 emissions controls are expected to become a reality in the United States with several legislative climate change targets having been proposed in the 110th Congress. Several measures are being considered as means to help decrease CO_2 emissions to the levels that are being widely considered as likely targets in impending regulations.

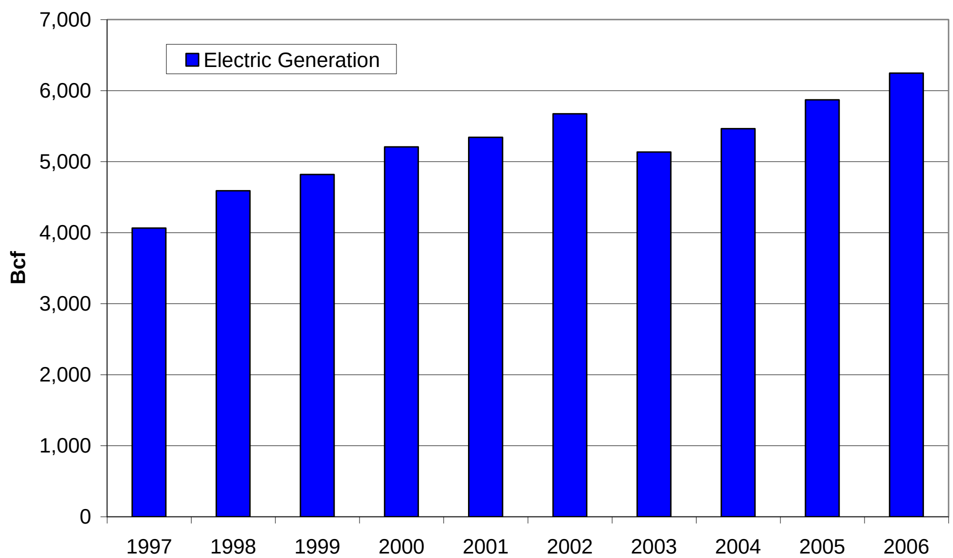
[3] "Public Policy and Real Energy Efficiency, Assessing the effects of Federal policies on energy consumption and the environment", October 2005, American Gas Foundation.
[4] "Source Energy and Emission Factors for Residential Energy Consumption", August 2000, American Gas Association ("AGA").

2.0 INTRODUCTION

There has been an unprecedented growth in the use of natural gas for power generation over the past ten years. Electric power generation has the option of using a diverse fuel mix which consists of coal, natural gas, oil, nuclear and renewables. No one fuel can provide all the electric generation needed, and a diverse fuel base has helped to provide a stable supply of electricity. The availability, price, and reliability of the supply as well as the government regulations applicable to the fuel are important factors that determine the fuel mix used for electric generation. Since the mid-90s, more than 90% of the generation capacity added has been gas-fired units for peaking and intermediate loads. Some of this growth in the use of natural gas for power generation was driven by environmental regulations and the high costs of coal-based generation plants. During this time frame there was a belief that the North American market had an unlimited supply of a relatively cheap and environmentally-friendly fuel available.

As seen in Figure 2.1, the use of natural gas for electric generation has increased by over 50% in the last 10 years.

Figure 2.1: Natural Gas Use for Electric Power Generation



Source: EIA

The increase in natural gas demand for the power generation as well as other sectors, coupled with supply constraints have driven an increase in natural gas prices from the $2/MMBtu to $3/MMBtu level of the 1990s to the $6/MMBtu to $9/MMBtu level seen in recent years. Even with relatively higher natural gas prices, demand for the use of natural gas in electric power generation has continued to increase and is driven by several factors.

One of the factors is efficiency. Combined-cycle gas turbines have an efficiency of about 51%.[5] The gas turbine technology is also very flexible. This allows for small or large amounts of power generation to be produced on demand. Peak demand is usually fulfilled by natural gas fueled generation due to its flexibility. This flexibility adds to the value of using natural gas for power generation and will likely continue to increase demand.

Emerging CO_2 emissions restrictions have also started driving increased demand for natural gas for power generation as the reliance on coal-fired generation decreases in a CO_2 constrained world.

Given the increased demand for natural gas for power generation and the emerging fundamental factors such as CO_2 emissions restrictions that are expected to drive the demand for natural gas even higher measures to optimize the use of natural gas need to be examined, specifically the use of gas for power generation in a sustained high gas price environment.

2.1 Purpose of the Study

The purpose of this report is to examine the market impact of the increased direct use of natural gas for Residential & Commercial ("R&C") end uses that can be powered by either natural gas or electricity and to examine the ongoing use of natural gas in power generation. Although there are several factors that drive the use of natural gas for power generation, there is a growing concern that the overall natural gas supply/demand balance could be impacted as the demand for natural gas for power generation continues to grow. The underlying premise of this study is to consider a series of future market scenarios that examine the impact of using natural gas for direct applications, especially at the R&C level.

The primary focus of the study is to assess the impact on overall energy usage, cost, and CO_2 emissions of a market with greater direct use of natural gas by R&C applications. For the study, 7% of the total electric load served by electric R&C applications is shifted to be served by natural gas.

While some of the long-term fundamental forecasts used in this study were based on the Energy Information Administration's Annual Energy Outlook (AEO) 2007, the early release of the AEO 2008 was reviewed. Several conclusions have been reached regarding the updated forecasts. The AEO 2008 forecasts a slight reduction in electric load growth from the 2007 forecast amounting to 5% less electric consumption in 2030. The AEO 2008 has increased nuclear generation by about 18 GW in 2030 over the flat forecast in AEO 2007. Eighteen GW amounts to approximately 1.5% of the projected installed capacity in the U.S. in 2030. Renewables generation is projected to grow much faster in AEO 2008 but still to amount to only 12% of the electric energy needs in 2030. As in the AEO 2007, no CO_2 restrictions are assumed. As a result, gas consumption for electric generation increases for a few years and then decreases markedly as significant new coal fueled generation is added. This trend is very similar to the forecast in the AEO 2007.

[5] B&V Analysis

In both forecasts, most of the new generating capacity additions and increased energy supply still has to come from either new gas or coal fueled generators. With no CO_2 controls, the long-term growth in gas demand for electricity will be slightly negative. With CO_2 controls, the long-term growth in gas demand for electric generation will be very positive regardless of the use of the 2007 or 2008 AEO forecast. Consequently, the savings in primary energy use, CO_2 emissions and the cost of energy from the increased direct use of natural gas are still expected to be significant with the use of the updated AEO 2008 forecast.

2.2 Study Overview

Section 3 of this report provides an overview of the growth and trends in the use of natural gas for power generation within the context of key drivers including the various technologies used to generate electricity in the United States, the capital costs related to the different fuels and technologies, the generation efficiencies and technological improvements, the relative fuel prices and availability and the current and anticipated environmental regulations.

Section 4 of this report presents an overview of the drivers of the growing use of natural gas. Natural gas possesses several characteristics that make it a premium fuel including high efficiency, reliability, application for diverse and emerging uses and significant environmental benefits.

Section 5 of this report outlines a detailed analysis of the impact of the increased direct use of natural gas for R&C applications rather than for power generation. Demand for electricity in the R&C sectors is assessed using EIA forecasts as a baseline. This demand analysis is further broken down by four applications that have the option of either using natural gas directly or electricity for their fuel source: space heating, water heating, cooking, and clothes drying. The analysis examines the impact of shifting a portion of the electricity demand for these four applications to the direct use of natural gas. For this study, a Reference Case and four different scenarios were developed to highlight key uncertainties in the natural gas market including supply and CO_2 emissions restrictions. The net impact of the increased direct demand for natural gas and the decrease in demand for electricity are measured in terms of the change in energy consumption, CO_2 emissions and energy costs.

3.0 OVERVIEW OF POWER GENERATION

3.1 Introduction

The power generation industry in the U.S. is facing a great number of challenges. Many of the challenges stem from the following situations:

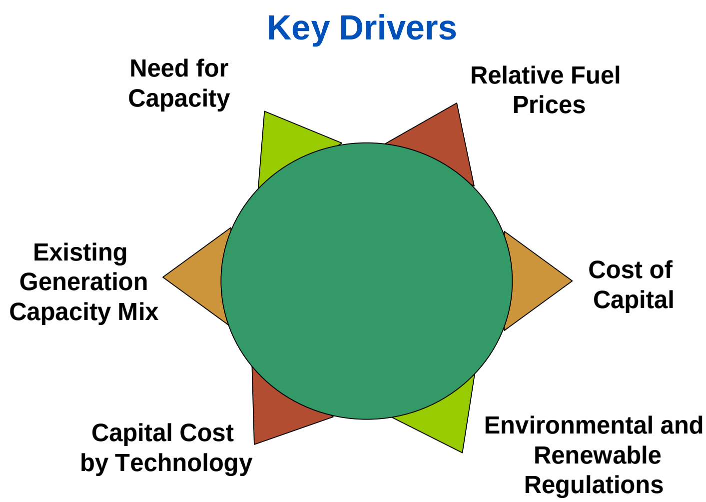
- Increasing national support for the regulation of greenhouse gas emissions including CO_2 - believed to be the major contributor to global warming
- Electric generation's contribution of 40% of the man-made CO_2 emissions in the U.S.
- Estimates of a potential increase in the cost of electricity on the order of 30%-100% resulting from compliance with currently proposed CO_2 emission limits.
- New pulverized coal generator permit denials for numerous proposed projects (Florida Power & Light's 1,800 MW Glades Project, AEP's Red Rock Project, Tri State's Holcomb Expansion, and 4 projects in TXU's proposed portfolio for Texas to name a few.)
- Reductions in the pipeline for new generation projects
- Diminishing regional reserve margins
- Growing reliance on natural gas to fuel electric generation in the future
- Additional concerns about energy independence stemming from increased reliance on imported LNG.

In spite of these uncertainties, the electric industry continues to expand to meet demand growth and fuel the economy. Historical load growth in the U.S. averaged just over 2% during the years 1995 to 2006. Under AEO's 2007 forecast, future U.S. load growth is forecast to continue to grow at 1.5% per year between 2007 and 2030. Assuming this lower forecast load growth occurs (EIA has a history of under predicting load growth.), the U.S. still needs approximately 300 GW of new generation capacity over the next 23 years. Between 2005 and early 2007, the pipeline of proposed new generators in the U.S. extended out through 2015 and contained over 150 new coal fueled generators. Some new coal projects came and went from the pipeline, but the planned new generators held at around 150. The current pipeline for new coal generators has recently slipped to 121, partly as a result of rapid increases in the capital cost of new coal generation and partly as a result of permit denials and new state-level prohibitions of new coal generators in the name of CO_2 control. At present only 45 new coal fueled generators are either under construction or have progressed past the likely point of cancellation.

It appears many utilities experiencing rejection of their plans to add coal generation will buy time by installing less capital intensive simple cycle combustion turbines in order to continue to meet required reserve margins. However, combustion turbines are just an interim solution. Electric utilities and independent generation companies must ultimately weigh the risks associated with attempting to construct new coal fueled generation against the risk of constructing gas fueled combined cycle generation and paying high natural gas prices for baseload generation.

Apart from the perception and political issues discussed above, the decisions regarding the timing and type of new generation (gas versus coal fueled) depends on the same factors they have for decades. Figure 3.1 shows these major factors.

Figure 3.1: Key Drivers Affecting New Generation Choices



The need for new capacity is critical to the timing of new generation additions. Under current regulatory conditions, it is economically difficult to build new generating capacity solely for the purpose of retiring existing capacity unless that existing capacity is facing a major repair or other capital investment such as additional air quality control requirements.

Relative gas and coal fuel prices and capital costs impact the decision to add coal or gas generation because it is the lower fuel cost of baseload coal generators compared to gas generators that offsets the capital cost premium of coal generation over gas generation. Likewise, the utility's or independent power company's cost of capital also impacts the amortized capital cost premium of coal generation over gas generation.

The existing fuel mix of the region in question impacts the ability of new coal generators to run at high capacity factors without displacing generation from existing coal generators. A few regions in the U.S. still contain more existing coal and nuclear capacity than is needed for the regional base loads and as a result, the addition of coal generation in these regions still pits these new coal plants against existing coal plants.

Finally, environmental limitations have always affected and will continue to affect selection of the best baseload technology. The forecast of generation additions in the AEO 2007 assume only those future environmental rules already promulgated. As such they consider the need to comply with such regulations as the Clean Air Interstate Rule, the Clean Air Mercury Rule, the Regional Haze Rule and the Industrial Boiler. For new generators, compliance with these rules, in the next 3 to 8 years, will have little influence on fuel selection because purchase of allowances for the few remaining emissions from these new highly controlled plants is expected to be small compared to the cost of purchasing fuel and operating the plant. The potential for CO_2 regulations, however, presents a very different picture as discussed in section 5 of this report.

3.2 Costs of New Baseload Generating Facilities in the U.S.

As discussed above, the relative capital and fuel costs of new coal fueled and gas fueled generating facilities significantly impact their selection to serve base loads by electric generators. And, while capital costs do vary by region, site specific factors can contribute more to differences in capital costs from one site to another rather than the regions themselves. Figure 3.2 presents recent estimates of the capital costs, heat rates and non-fuel operating costs for large new super critical coal and gas fueled generators. As shown in Figure 3.2, the capital costs of new coal fueled generation is roughly three times that of new gas fueled combined cycle generation. At an 85% capacity factor, the non-fuel operating costs of the coal generator are slightly lower than that of the combined cycle generator. The combined cycle heat rate is 79% of the super-critical coal fueled heat rate implying a 27% higher efficiency. Before the fuel costs of these two generator types can be meaningfully compared, their respective heat rates must be applied to delivered fuel prices. Delivered fuel prices, especially coal prices, can vary significantly by region of the U.S. To illustrate this variation, Figure 3.3 illustrates the ratio of delivered gas to coal fuel costs in the various market regions of the U.S. based on the AEO 2007 Reference Case forecast of gas prices by region. From Figure 3.3, it appears that the best opportunities for adding new coal fueled generation capacity appears to be in the MAPP, Other WECC and Rocky Mountain regions at least from a fuel price perspective.

Figure 3.2: Capital and Operating Costs for Alternative Baseload Generators $2007

500-600 MW SCPC Plant

- Capital – $2,508/ kw*
- Fixed O&M – $33/ kw-yr
- Variable O&M – $3 / MWh
- Full Load Heat Rate – 9,100 Btu / kWh
- CO_2 Emissions – 0.99 T/MWh

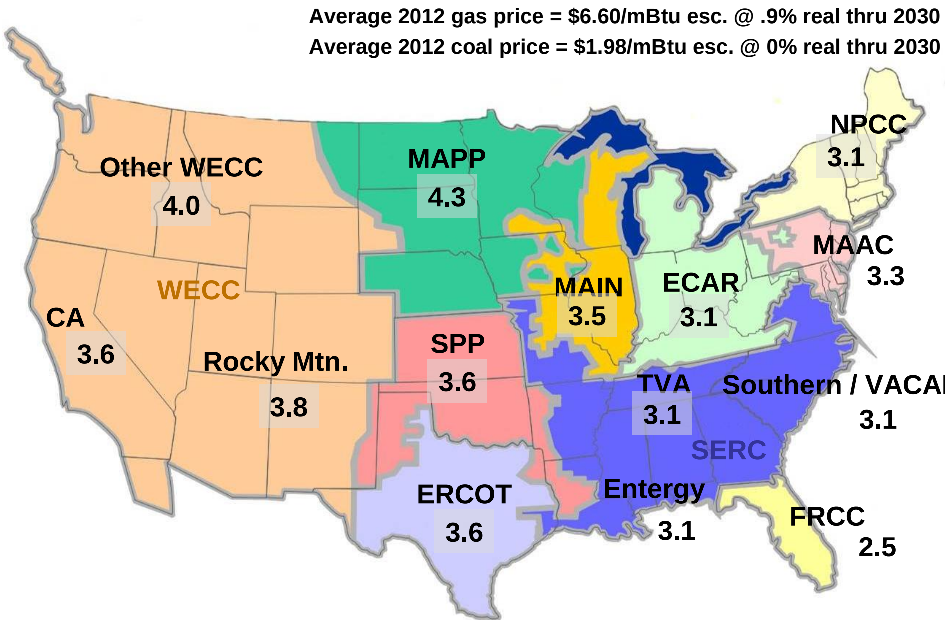
500 MW Combined Cycle

- Capital – $832/ kw**
- Fixed O&M – $5 / kw-yr
- Variable O&M – $5 / MWh
- Full Load Heat Rate – 7,200 Btu / kWh
- CO_2 Emissions - 0.433 T/MWh

- Reflects currently high capital costs (Approximately 30% for SCPC and 12% for CC above the equilibrium).
- Heat rates reflect average operating heat rates and the inevitable inefficiencies associated with plant start-up and shut-down.

* Includes a 32% Allowance for Owner Costs, AFUDC and Financing Fees
** Includes a 28% Allowance for Owner Costs, AFUDC and Financing Fees

Figure 3.3: Ratio of Delivered Gas to Coal Prices by Region



3.3 Baseline Forecast of New Gas and Coal Fueled Generator Additions in the U.S.

In accordance with the approach and methodology set out in Section 2 of this report, the capital and operating costs of the generators described above was used along with the forecast delivered fuel prices in the AEO 2007, estimates of the need for additional generating capacity, and the existing generation mix by region, to feed its generation expansion and production cost model of the U.S. electric generation system by region. Figure 3.4 presents the estimated need for new capacity and Figure 3.5 presents the existing capacity mix by region.

From Figure 3.4 the regions most in need of additional generating capacity are Southern/VACAR, California and MAIN and ECAR (much of which currently constitutes the area controlled by the Midwest Independent System Operator or MISO). Only Entergy currently has enough existing capacity to meet its load needs through 2015.

Figure 3.4: Additional Capacity Needs by Region by 2015/2030 in GW

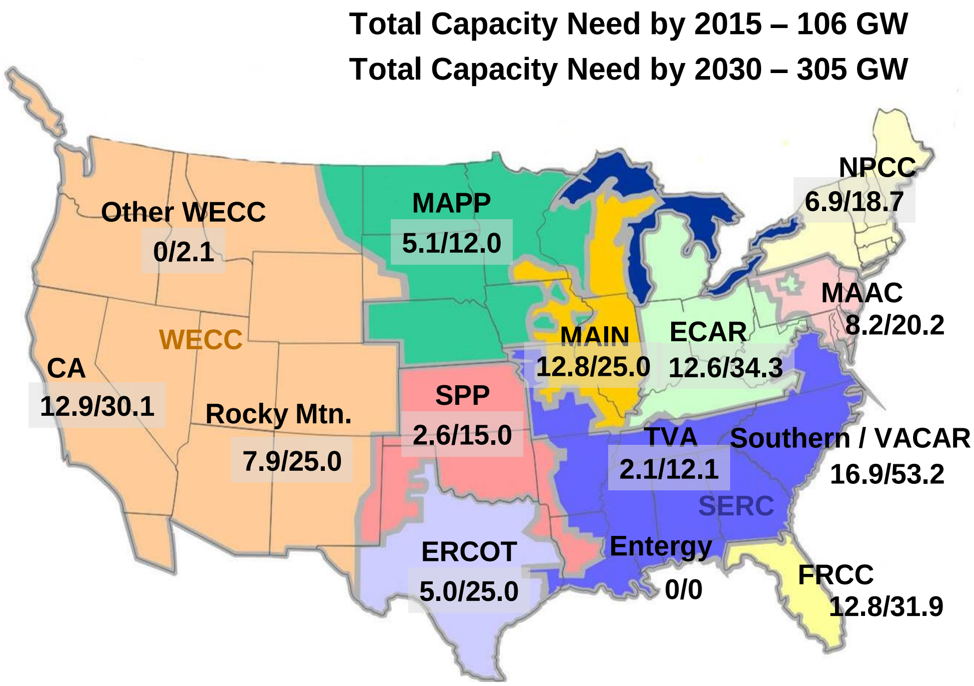
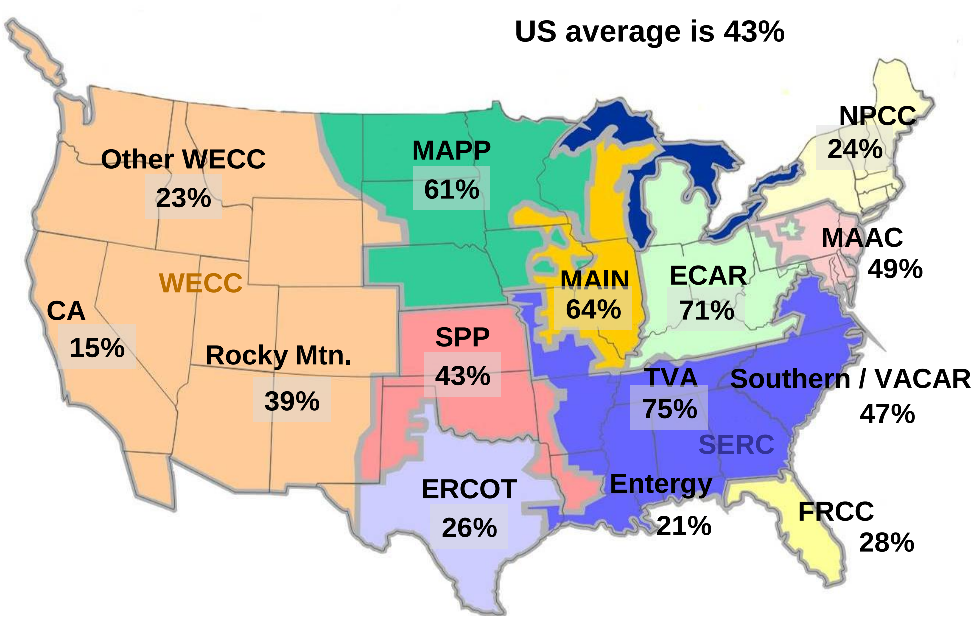


Figure 3.5: Existing Percent Coal and Nuclear of Total Capacity

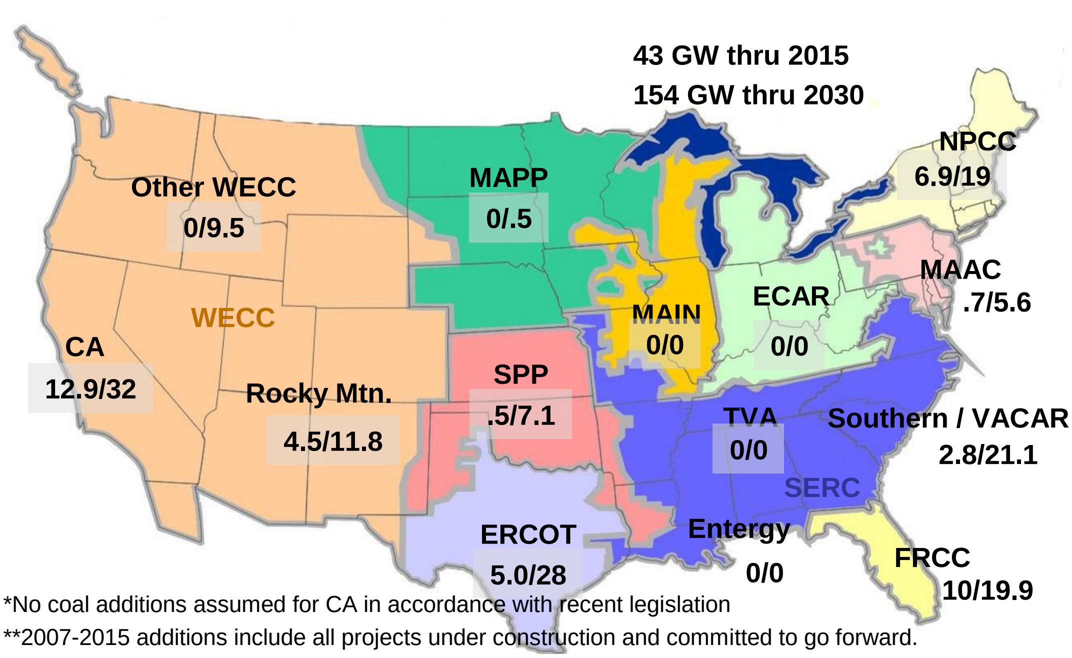


From Figure 3.5 we see that the ratios of existing coal and nuclear capacity to total capacity are lowest in California, Other WECC, Entergy and ERCOT indicating these regions would be most in need of additional coal fueled generating capacity from the capacity mix perspective.

Use of all the foregoing inputs in a simplified generation expansion model for each region of the U.S. yielded a forecast of economic new coal generation additions very close to the forecast contained in the AEO 2007 Reference Case generation expansion plan. For purposes of forecasting the natural gas use for electric generation, the forecasts of petroleum and renewable generation contained in the AEO 2007 Reference Case forecast was used along with our economic expansion and dispatch model to estimate the percent of remaining generation requirements by region that would be supplied by nuclear, existing coal and new coal generation, leaving the remainder to be supplied by existing and new gas generators. Figure 3.6 contains the resultant forecasts of economic new coal capacity additions by region in the U.S. While there are some differences between the AEO and the study forecasts on a regional basis, the total net coal capacity additions forecast in the AEO between 2005 and 2030 amounted to 139 GW. (An additional 6 GW of new generation additions were forecast to replace existing aging coal fueled generators.) The comparable forecast of new coal fueled capacity additions for the U.S. from the B&V model was 141 GW. Due to the close match of these two forecasts, B&V was confident that its economic expansion and dispatch model would be appropriate to forecast marginal generation fuels by region under alternative scenarios of fuel price, end use technology advancement and CO_2 emission constraints.

While the forecast of coal fueled additions in Figure 3.6 includes capacity additions in states that have either legislated or declared their intent to prohibit additional conventional coal fueled generator additions (California, New England, Florida, etc.), B&V retained this forecast capacity in order to reflect the potential for a reversal of these constraints once the full economic consequences are felt. The scenarios calling for moderate and stringent CO_2 limits nation-wide will encompass these state level restrictions.

Figure 3.6: Economic Coal Capacity Additions by Region – Baseline GW 2007-2015 / 2007-2030

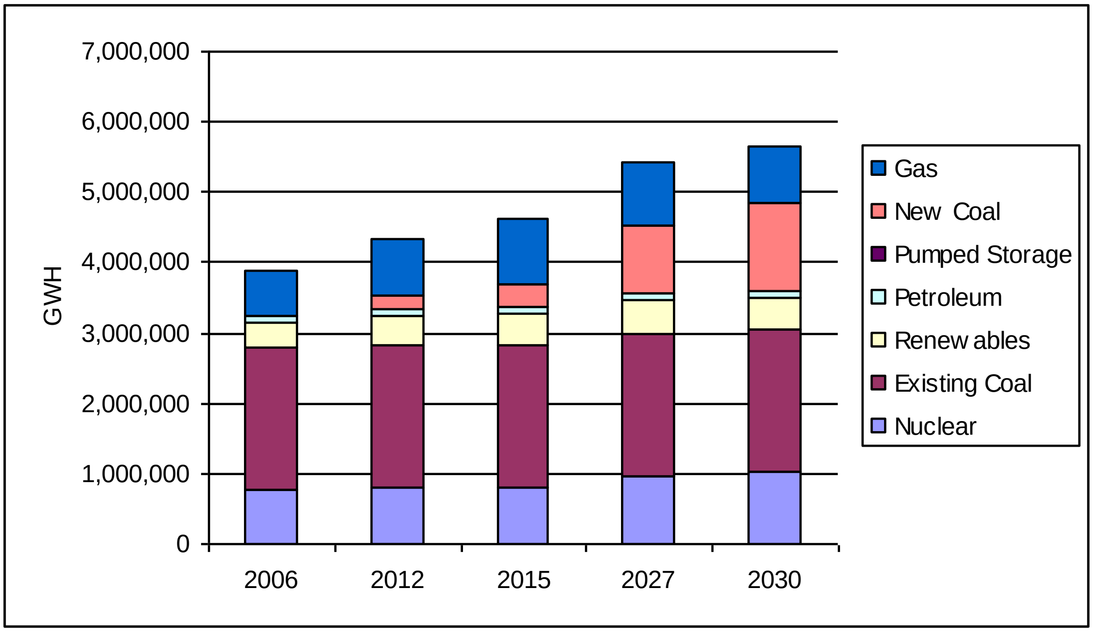


*No coal additions assumed for CA in accordance with recent legislation

**2007-2015 additions include all projects under construction and committed to go forward.

Figure 3.7 illustrates the forecast growth in electricity generation (GWh) by fuel type in the Reference Case Baseline as simulated in the study model. The graph reflects increased generation from the addition of coal capacity (excluding California).

Figure 3.7: Forecast Electric Generation by Fuel Type - Reference Case Baseline



Source: EIA, B&V Analysis

4.0 DRIVERS OF GROWING NATURAL GAS DEMAND

Natural gas is a very reliable, efficient, and environmentally friendly fuel with widespread uses and applications. It is the cleanest burning fossil fuel for power generation. Many aspects of natural gas make it a premium fuel which is shown by the recent increase in demand.

Natural gas is considered a reliable fuel source for many different sectors and applications. Eighty five percent of natural gas consumed in the United States is produced domestically. The remaining 15% is mostly produced in North America.[6] Compared to the U.S. oil supply, which relies heavily on imports, natural gas provides a stable, domestically produced supply.

Proven and unproven reserves in the U.S., that are technically recoverable, are estimated to be 1,341 trillion cubic feet as shown in Figure 4.1. The production of unconventional natural gas recovery is the largest source of new domestic natural gas production. Unconventional production consists of tight gas sands, coalbed methane, and shale. The production of these gas sources will require further advancement in technology to provide more efficient and cost effective recovery. The area with the fastest growth in unconventional gas resources is East and Central Texas.[7]

[6] National Gas Supply Association
[7] Oil & Gas Journal, "Resource Potential Estimates Likely to Change", September 17, 2007

These reserves utilize an extensive and highly efficient transportation system that allows virtually seamless access to regional and national market centers. Some of these market centers provide services that facilitate the transportation process of natural gas by providing internet-based access to capacity release programs and trading platforms.

Figure 4.1: Natural Gas Technically Recoverable Resources

Natural Gas Resource Category (Trillion Cubic Feet)	As of January 1, 2005
Lower 48 Nonassociated Conventional Gas	
Undiscovered	**283.36**
Onshore	119.06
Offshore	164.3
Deep	106.3
Shallow	58
Inferred Reserves	**225.9**
Onshore	175.85
Offshore	50.05
Deep	5.95
Shallow	44.1
Unconventional Gas Recovery	**447.52**
Tight Gas	277.73
Shale Gas	125.81
Coalbed Methane	73.99
Associated-Dissolved Gas	**130.84**
Total Lower 48 Unproved	**1117.62**
Alaska	**30.83**
Total U.S. Unproved	**1148.45**
Proved Reserves	**192.51**
Total Natural Gas	**1340.97**

Source: EIA, AEO 2007

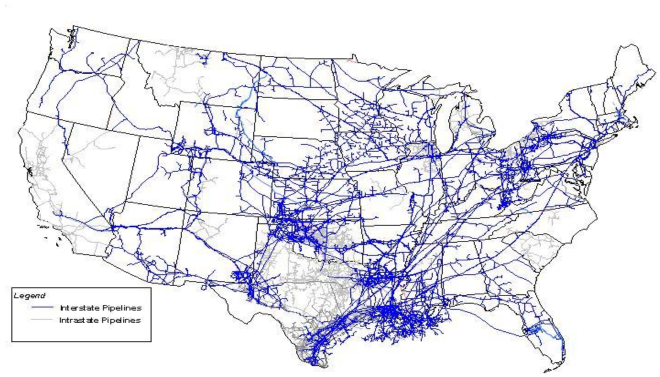
4.1 Reliability of Natural Gas

As mentioned above, the underground pipeline transportation system is very well developed and adds to the reliability of natural gas. There are over 200,000 miles of pipelines in the United States dedicated to the transportation of natural gas.[8] This vast infrastructure, shown in Figure 4.2, essentially moves gas from the producing regions in the Gulf Coast, Southwest, Mid-Continent, and Rockies regions to local distribution companies ("LDCs") or directly to the end users.

[8] Interstate Natural Gas Associate of America, "Reliable, Continuous Delivery of Natural Gas"

This system will only expand in the future since there are over 25 proposed projects over the next several years that will add 17.11 Bcf/day capacity and 4,344 miles of pipelines.[9] In addition, there are even more pending and approved pipeline projects that will expand capacity over the next couple of years. This extra capacity will reduce the amount of natural gas production that might be shut-in due to transportation restrictions.

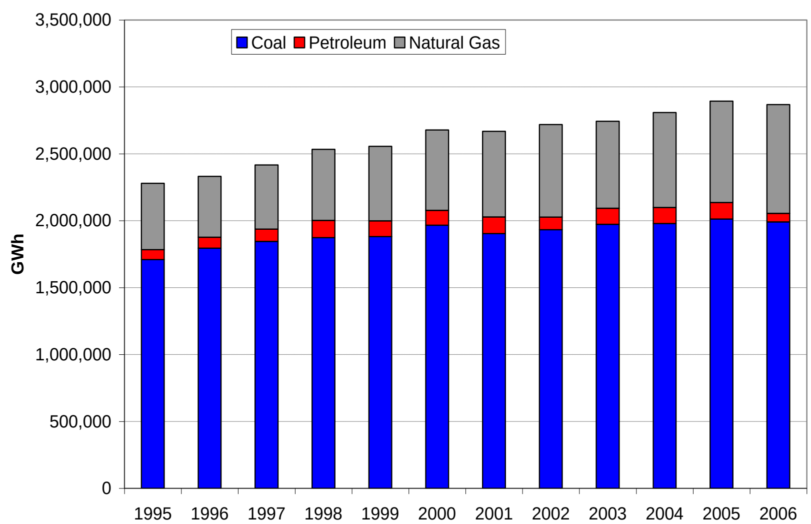
Figure 4.2: United States Natural Gas Pipeline Network



Source: EIA, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Weather related interruptions for the delivery of natural gas occur less often than electricity since the pipeline infrastructure is primarily underground. Figure 4.3 shows historical electricity generation (GWh) for coal, petroleum and natural gas. The graph reflects that the use of natural gas for electricity generation has been growing at an annual rate of 4.8% from 1995 to 2006 compared to 1.4% for coal and 1.6% for petroleum.

Figure 4.3: Electricity Generation by the 3 Major Fuel Sources



Source: EIA

[9] Federal Energy Regulatory Commission ("FERC"), "Major Pipeline Projects on the Horizon"

Most storage facilities for natural gas are also underground which makes them subject to less weather related interruptions. In addition, storage allows for the withdrawal of natural gas during peak demand periods, such as the winter heating season, and increases the overall reliability of gas.

The reliability advantages of the underground gas infrastructure was exhibited during the 2004 and 2005 hurricane seasons that had a major impact on the production of natural gas in the Gulf Coast region. Ivan created 174 Bcf of production shut-ins while Katrina and Rita have estimated production shut-ins of 900 to 1,100 Bcf.[10] Although natural gas prices rose significantly, natural gas delivery to end-use customers was only minimally disrupted.

4.2 Natural Gas Efficiency

Natural gas is not only reliable but efficient as well. According to a previous AGF study, energy efficiency can be measured in three ways.[11] The methods analyzed in this report are the site energy and real energy methods. The site energy method measures efficiency by only taking into account the efficiency of the appliance used by the customer. It does not take into account the efficiency of the process from acquiring and delivering the energy for use like the real energy method does. This method provides a more realistic measure of efficiency since it includes the overall energy acquisition process.

In general, appliances that run on natural gas are more efficient when using the real energy method because the natural gas process from production to delivery is more efficient than the process for electricity. Many of the policies regarding efficiency are, however, based on site energy. Electric powered appliances may be used more as a result of these policies since their efficiency, when using the site energy method, may be higher than natural gas appliances. Since the electric process from production to delivery is less efficient than the natural gas process, this may actually encourage more energy consumption.

The total delivery efficiency is 90% for natural gas use from the point of extraction to the end user. This is very high when it is compared to the total delivery efficiency for electricity use which is only 27%.[12]

There has been a recent trend to improve appliance efficiencies with the enactment of the Energy Policy Act of 2005 which offers tax credits for appliance manufacturers, home builders, commercial buildings, and consumers. There are also state-wide programs that offer rebates as incentives for customers to buy more energy efficient appliances as well as to replace old appliances with new ones.

[10] Energy and Efficiency Analysis, Inc. "Hurricane Damage to Natural Gas Infrastructure and Its Effects on the U.S. Natural Gas Market" November 2005

[11] "Public Policy and Real Energy Efficiency, Assessing the effects of Federal policies on energy consumption and the environment", October 2005, American Gas Foundation

[12] "Public Policy and Real Energy Efficiency, Assessing the effects of Federal policies on energy consumption and the environment", October 2005, American Gas Foundation

4.3 Environmentally Friendly

Natural gas emits the lowest amount of emissions out of the mix of fuels used for electricity generation as shown in Figure 4.4. Natural gas pollutants account for 23.9% of carbon dioxide emissions within these 3 fuel types. Natural gas produces the least pounds of emissions for every pollutant except for formaldehyde. However, those emissions are very small compared with the rest of the pollutants. The increased use of natural gas can help reduce the harmful effects of these emissions on the environment.

Figure 4.4: Pounds of Air Pollutants per Billion Btu of Energy

Pollutant	Natural Gas	Oil	Coal
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur Dioxide	0.6	1,122	2,591
Particulates	7	84	2,744
Formaldehyde	0.75	0.22	0.221
Mercury	0	0.007	0.016

Source: EIA, Natural Gas 1998: Issues and Trends

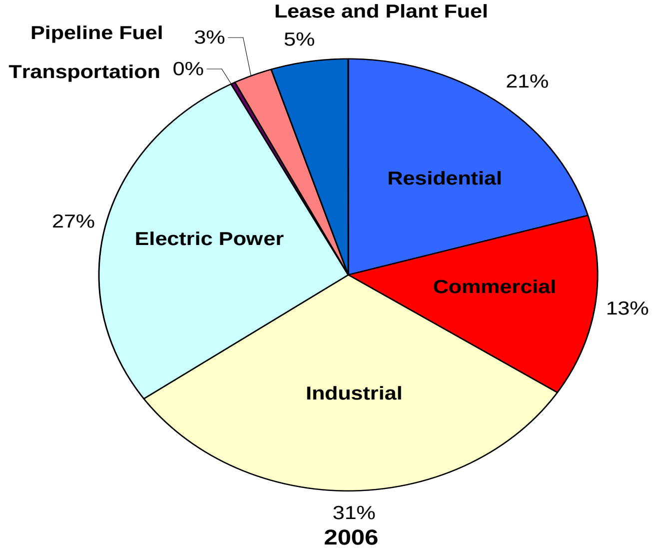
One of the most pressing environmental issues today is the emission of greenhouse gases. The increase in these gases is partly due to the widespread burning of fossil fuels needed to meet the increasing energy demand. Since carbon dioxide emissions make up the majority of greenhouse gases, these emissions are generally targeted by policymakers, and therefore regulations that decrease carbon dioxide emissions will also cause an overall decrease in greenhouse gases. From 1990 to 2004, carbon dioxide emissions increased by 20% while methane emissions decreased by 10% and nitrous oxide emissions decreased by 2%.[13] The use of natural gas contributes almost 30% less carbon dioxide emissions than oil and almost 45% less than coal.[14]

4.4 Diverse Uses of Natural Gas

Natural gas consumption accounted for 22% of total energy consumption in 2006.[15] As seen in Figure 4.5, the R&C sectors consume 21% and 13% of natural gas, respectively, while the industrial sector consumes the most at 31%. About 27% of natural gas consumption is used for power generation. Other uses of natural gas include aiding in the production of fertilizer and the manufacturing of steel, plastics, glass, and other items.[16]

[13] Fourth U.S. Climate Action Report
[14] NaturalGas.org
[15] EIA
[16] EIA

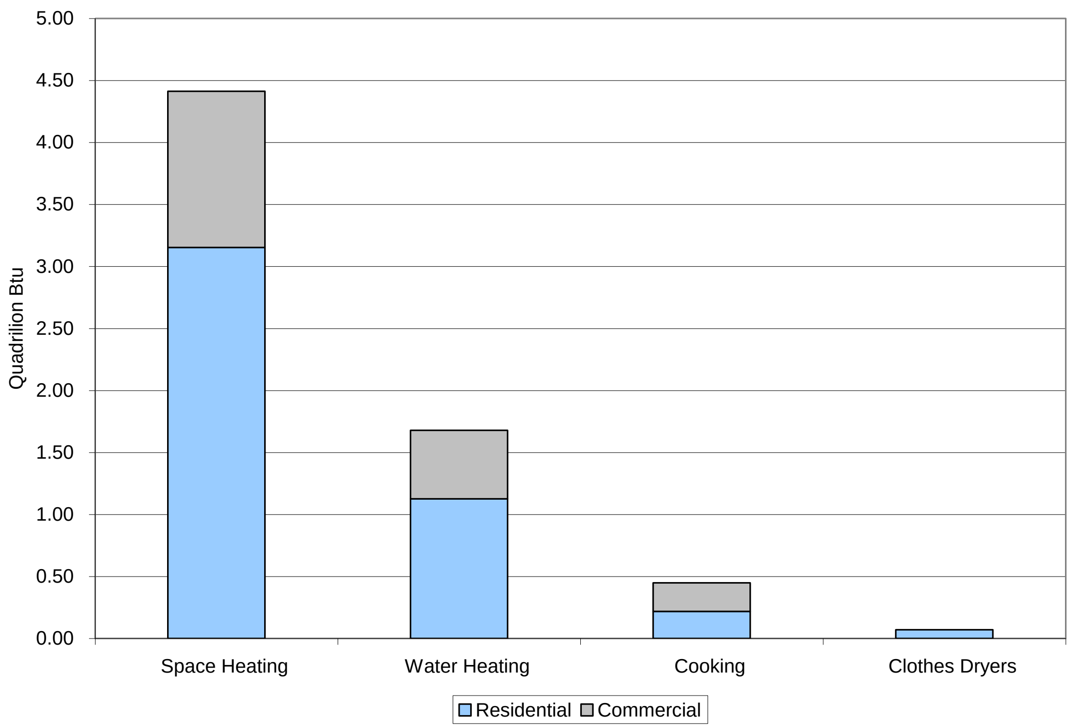
Figure 4.5: Natural Gas Consumption by Sector



Source: EIA, AEO 2007

The majority of natural gas consumption in the residential sector is consumed by the four applications shown in Figure 4.6: cooking, clothes drying, space heating, and water heating. Space heating is the largest application use for natural gas in the residential sector as well as in the commercial sector. Both of these sectors use natural gas for similar applications.

Figure 4.6: Natural Gas Consumption by R&C Applications, 2006



Source: EIA, AEO 2007

Almost three-fourths of annual natural gas consumption occurs during November to March.[17] From this large use of natural gas for space heating, we can infer that many new homes have the ability to receive natural gas thus making it easier for consumers to purchase natural gas powered appliances. These appliances usually have a higher initial cost than its electric powered counterpart but the natural gas powered appliance usually has a lower operating cost and requires less maintenance.

There are also several emerging uses for natural gas as well. One of them is natural gas powered space cooling for buildings. This will potentially increase the use of natural gas to meet summer cooling demand. Natural gas is used to produce hydrogen which is used as a chemical feedstock and as a fuel source for hydrogen powered vehicles. However, natural gas can also be directly used as feedstock for chemical and product manufacturing. Butane, ethane, and propane extracted from natural gas, are also used as feedstock.[18]

Natural gas use for cogeneration has improved due to new advances in technology. This was traditionally used to produce electricity and heat energy that was not reused. Now the heat energy can be used to produce electricity through a turbine. This is expected to save 10% to 30% of the fuel used to produce the same amount of electricity and heat energy separately.[19]

[17] U.S. Natural Gas Markets: Recent Trends and Prospects for the Future, May 2001, EIA
[18] NaturalGas.org
[19] Country Energy

5.0 IMPACT OF NATURAL GAS USE FOR POWER GENERATION AND DIRECT RESIDENTIAL & COMMERCIAL USAGE

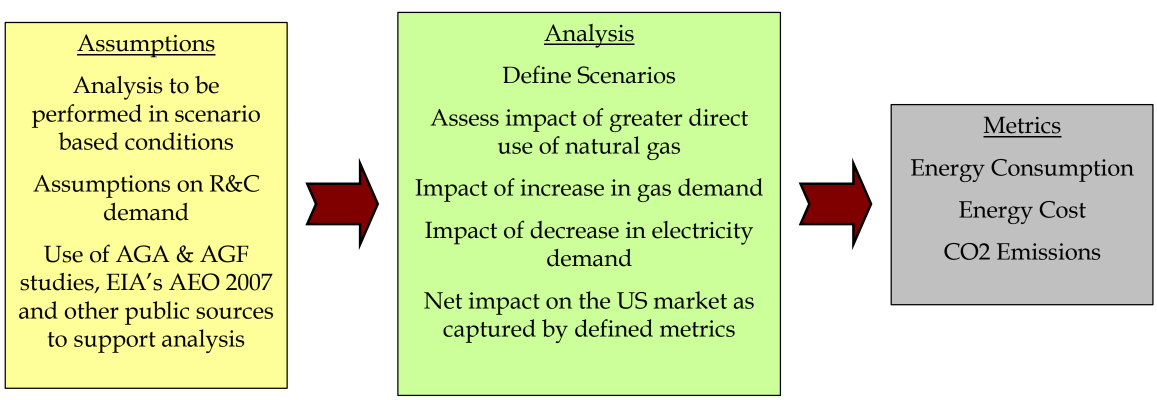
5.1 Overview of Approach

The analysis focused on the effect of an increased direct use of natural gas on expected use of gas for electric generation and the net effect in total energy use, energy costs and CO_2 emissions. The impacts of the direct use of natural gas for R&C applications were analyzed within the context of multiple scenarios representing the natural gas market in the U.S. Further, this study assumes that growth in the industrial demand for natural gas would be driven by organic demand growth and new applications for natural gas emerging through time rather than through switching from the use of electricity to natural gas for industrial purposes.

Assumptions derived from the EIA's AEO 2007 were utilized to develop forecasts for consumption, prices and other inputs to the analysis.[20] These assumptions have also been supported by prior studies by AGF and other public sources that are cited in this report where applicable. The study does not attempt to assess the likelihood or probability of the assumptions or scenarios examined. Rather, it attempts to design and utilize assumptions and scenarios that reflect a reasonable range of outcomes in order to assess the impact to the U.S. energy market if the conditions examined occur in the future. Three metrics were selected to measure the impact from increased direct use of natural gas for R&C applications. They are energy consumption, energy cost and CO_2 emissions and will be defined in more detail later in this Section.

Figure 5.1 presents an overview of the analysis approach used in the study.

Figure 5.1: Analysis Approach



[20] "Annual Energy Outlook 2007 With Projections to 2030", EIA, Office of Integrated Analysis and Forecasting, U.S. Department of Energy. DOE/EIA-0383 (2007), February 2007.

5.2 Description of Scenarios

Five scenarios were developed to capture and represent key drivers of uncertainty within the natural gas market. The key uncertainties that have been captured in the scenarios are the natural gas supply, technology for R&C applications and the environmental regulations related to CO_2 emissions. The combinations of these three variables create five distinct scenarios that form the background for the analysis examining the impact of the direct use of natural gas for R&C applications rather than for power generation as shown in Figure 5.2.

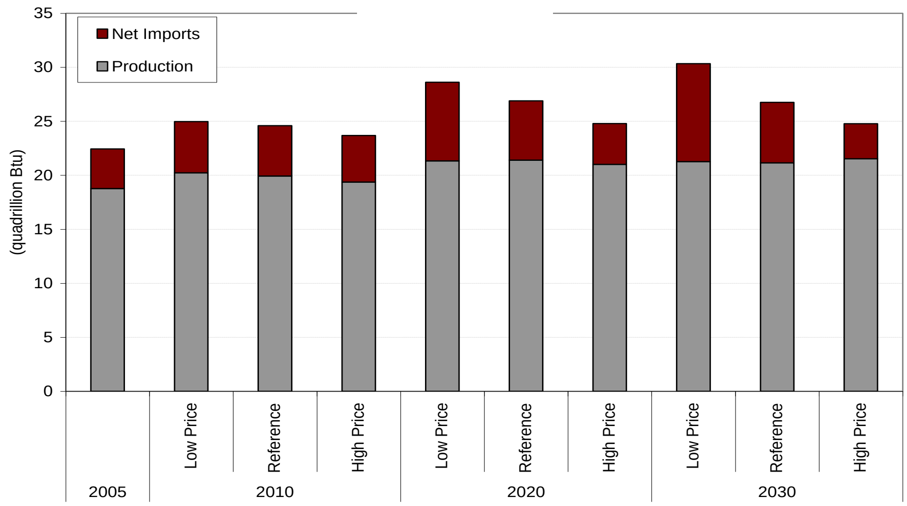
Figure 5.2: Scenarios Considered in the Study

Scenarios	SUPPLY	TECHNOLOGY	ENVIRONMENTAL
Scenario 1: Reference Case	Reference Case	Reference Case (Improvements over Current Technology)	Reference Case (No CO_2 Restrictions)
Scenario 2: Natural Gas Supply Lower			
Scenario 2a: Natural Gas Supply Lower & High Technology	Low Supply	High Technology	High CO_2 Restrictions
Scenario 2b: Natural Gas Supply Lower & 2006 Technology	Low Supply	2006 Technology	High CO2 Restrictions
Scenario 3: Natural Gas Supply Higher			
Scenario 3a: Natural Gas Supply Higher & High Technology	High Supply	High Technology	Low CO_2 Restrictions
Scenario 3b: Natural Gas Supply Higher & 2006 Technology	High Supply	2006 Technology	Low CO_2 Restrictions

5.2.1 Supply

In order to capture high and low supply scenarios, this analysis utilized the assumptions of the supply sensitivities from the integrated price cases in the AEO 2007. The low price case assumes that world crude oil and natural gas supplies are 15% higher than assumed in the Reference Case. The high price case assumes that world crude oil and natural gas supplies are 15% lower than assumed in the Reference Case. Of note, supply is natural gas supply from production, not the total overall resource base of natural gas in the earth. Figure 5.3 shows the assumptions for total natural gas supply in the U.S. market in the price sensitivity cases.

Figure 5.3: Comparison of Total Natural Gas Supply in U.S. (Price Cases)



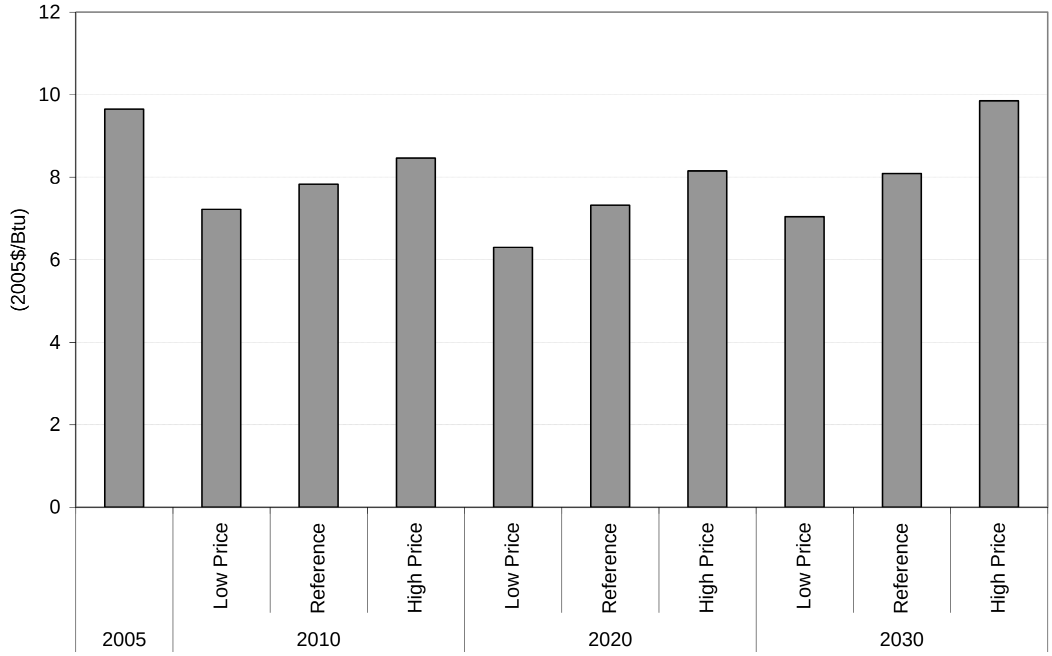
Source: EIA, AEO 2007

The high supply (Low Price) assumption drives lower prices for natural gas as well as higher consumption of natural gas during the analysis period, relative to the Reference Case. Conversely, the low supply (High Price) assumption drives higher prices for natural gas and lower consumption of natural gas during the analysis period, relative to the Reference Case. Figure 5.4 shows the comparison of the average price of natural gas for all users in the Reference Case as well as the Price Cases.

Fundamental analysis of the market is best suited to determine the impact of the interplay between supply, demand and prices. Since fundamental analysis of the natural gas market was not within the scope of this study, EIA's Price Cases were utilized to derive an elasticity for natural gas in order to compute the price impact of change in gas demand considered in this analysis. The results from the Price Cases indicated elasticity of 30%[21] for natural gas i.e., for each 1% increase in gas demand the natural gas price increases by 0.3%. Once the impact on the natural gas consumption was estimated from greater direct use natural gas for R&C applications, this elasticity assumption is utilized to estimate the impact on energy cost.

[21] The short-run price elasticity is probably closer to 20%; however, this analysis assumes the application of a long-term policy of increased direct gas use.

Figure 5.4: Comparison of the Average Price of Natural Gas for All Users (Price Cases)



Source: EIA, AEO 2007

5.2.2 Technology

The technology being used for R&C applications impacts the consumption of energy for these applications. With higher technology, energy consumption is lower due to higher efficiencies of appliances and building shell efficiencies. With lower technology, energy consumption for the R&C sectors is higher due to lower efficiencies of appliances and building shell efficiencies.

According to a study by the American Gas Association, the average customer uses 13.9% less energy currently than in 2000. Of this decline, 43% is due to efficiency increases from natural gas powered appliances and tighter homes.[22] The continued improvement of appliance efficiencies will further decrease energy consumption not just natural gas consumption. An increase in efficiency for electric powered appliances will also cause a decrease in electricity consumption. The opposite would hold true with lower efficiencies.

The study captures the impact on natural gas and electricity consumption in the R&C sectors assuming low (2006) and high technology for residences and commercial buildings going forward based on EIA's AEO 2007 R&C technology cases as described in further detail below.

[22] An Economic Analysis of Consumer Response to Natural Gas Prices, AGA

2006 Technology

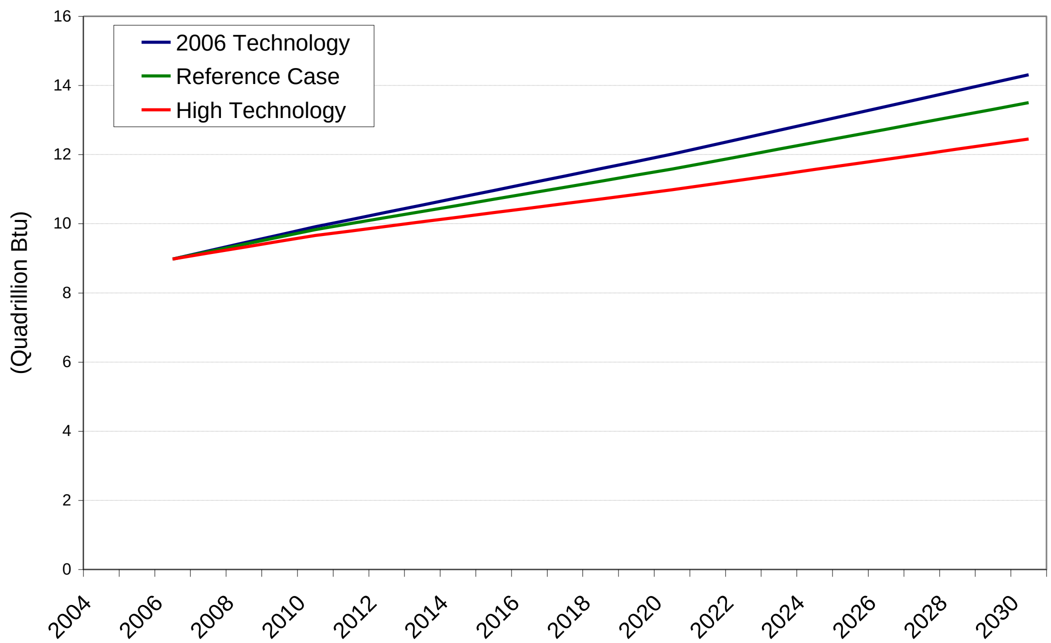
This case assumed that all future equipment purchases are based on equipment available in 2006 for the R&C sectors. Existing building shell efficiencies are fixed at 2006 levels for the residential sector. There are no improvements in efficiency over the current levels. For the commercial sector, existing building shells are permitted to increase by 5% over 2003 levels in the reference case. Also, new building shells in the commercial sector improve by 7% by 2030 relative to new buildings in 2003.

High Technology

Lower costs, higher efficiencies, and earlier availability assumed for more advanced equipment for the R&C sectors. Engineering technology experts developed the equipment assumptions by considering the potential impact of increased research and development for more advanced technologies. For the residential sector, building shell efficiencies as well as any new construction meet Energy STAR requirements after 2010. For the commercial sector, building shell efficiencies increase by 8.75 % by 2030 for new buildings and 6.25% for existing buildings. Commercial building shell efficiencies in the high technology case are set to improve 25% more than the reference case after 2006.

Figure 5.5 shows the estimated electricity consumption for R&C applications in the Technology Cases.

Figure 5.5: Electricity Consumption for R&C Applications – Technology Scenarios



Source: EIA, AEO 2007, B&V Analysis

5.2.3 Environmental Regulations

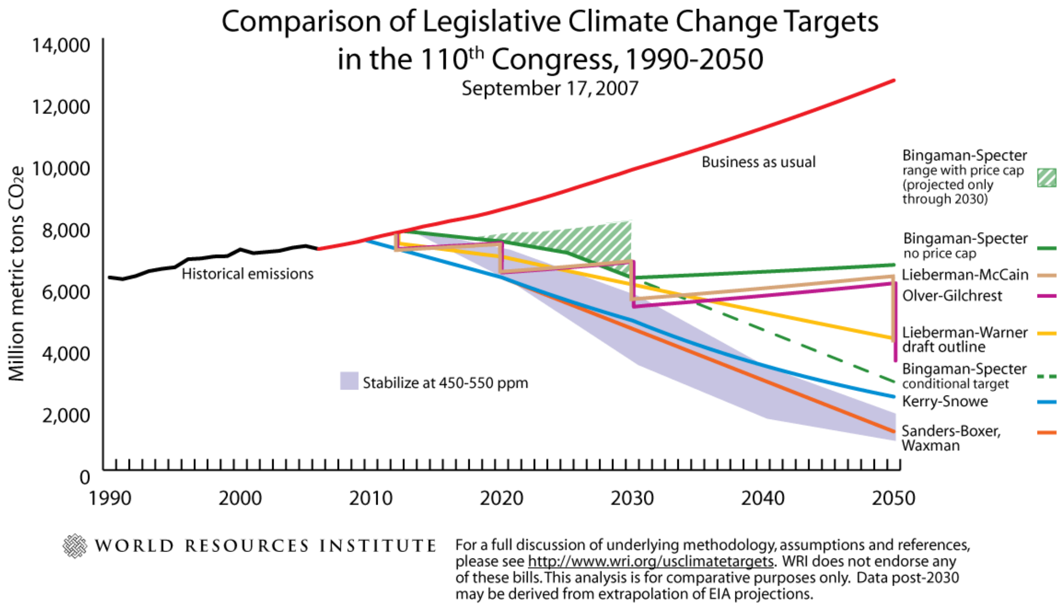
Environmental regulations, specifically CO_2 restrictions on the electric industry, have been modeled as cap and trade programs which induce implementation of the least-cost control measures first. Implementation of such measures will be assumed in the development of alternative electric future scenarios under which the impact of the greater direct end use of natural gas will be measured.

In addition to the Reference Case, High and 2006 Technology and Gas Supply Higher and Lower scenarios previously described, B&V hypothesized two additional scenarios reflecting implementation of moderate and stringent controls on CO_2 emissions from the U.S. electric sector. In both scenarios, implementation of a Cap and Trade program for CO_2 control was assumed in which electric generators are required to surrender one emission allowance for each ton of CO_2 they emit. EPA, if it is the administering agency, issues allowances equal to the targeted CO_2 cap which is some fraction of the current total emission level. Generators must then decide if it will be less expensive to: 1) install emission control equipment, 2) buy allowances to continue producing emissions, 3) install less expensive and less effective control equipment and buy allowances for remaining emissions, or 4) shut down because they will no longer be competitive with other generators in the market. The expectation is that a market will form for the allowances and those generators that can control emissions less expensively will do so on their own behalf and on behalf of those generators facing very expensive control costs. Generators facing less costly control costs will be induced to over-control in exchange for allowance sales revenues. Allowances may be given to generators facing control costs, auctioned to the generators with auction proceeds going to R&D programs or allocated to industry and population segments anticipated to suffer hardships from the cost of CO_2 control (hardship allocation would yield income for its recipients as generators must purchase allowances in order to operate).

The initial dispensation of allowances is relevant only to the ultimate impact on the price of electricity and not to the expansion of one generation type over another (gas fueled generation as opposed to coal fueled generation). The level of the cap of CO_2 emissions, however, will determine the economic viability of adding new coal fueled generating units to meet load growth in the U.S. Because new gas fueled combined cycle generators emit roughly 44% of the CO_2 emitted by new super-critical pulverized coal generators, the lower the CO_2 cap, the harder it is to keep adding conventional coal fueled generators for growth. In fact, with stringent regulations (a low CO_2 emissions cap) it is hard to justify the continued operation of some existing coal fueled generators.

The 1997 Kyoto Protocol marked an attempt to regulate CO_2 and other greenhouse gases globally. It was not signed by the U.S., but it has been followed by a long list of proposed bills which have become more restrictive in the last year in spite of the failure by most of Europe and Canada to even come close to the target emission levels. Figure 5.6 illustrates a business as usual forecast of nation-wide CO_2 emissions along with proposed caps under nine recent proposals to limit CO_2. According to U.S. DOE, the electric industry is responsible for 40% of current U.S. CO_2 emissions implying that the proposals in Figure 5.6 mean significant reductions in CO_2 emissions from the electric sector. It is estimated that the electric utility sector emitted 2,401 million tons of CO_2 in 2006.

Figure 5.6: CO_2 Emissions Comparison



This study chose the Lieberman-Warner proposal as the basis of the High CO_2 scenario with a 2030 cap of 27% of 2005 emissions which was recently modified to include a larger section of the U.S. economy. For the electric industry, this equates to 1,378 metric tons or 1,516 million short tons by 2030. For purposes of this analysis, a Low CO_2 control scenario was considered in which the 2030 cap on CO_2 emissions from the electric industry would be set at a level that discourages U.S. electric generators from adding coal fueled generation beyond those generators currently under construction. Under this scenario, all new generation additions to meet growth are assumed to be gas fueled; however little to no existing coal fueled generation is assumed to be shut down. In the absence of other factors (under the Reference technology and gas price scenario) the 2030 cap on electric industry CO_2 emissions that eliminates future coal fueled generator additions is approximately 2,915 million tons.

At some higher gas price point, depending on the cost of controlling CO_2 emissions in coal fueled generators using emerging technologies for capture and storage, it may become less costly to apply any or all emerging coal fueled technologies to existing and new coal generators in place of the use of gas generation to meet load growth and replace existing coal generators. The primary technologies under consideration for carbon capture at coal fueled electric generators are as follows:

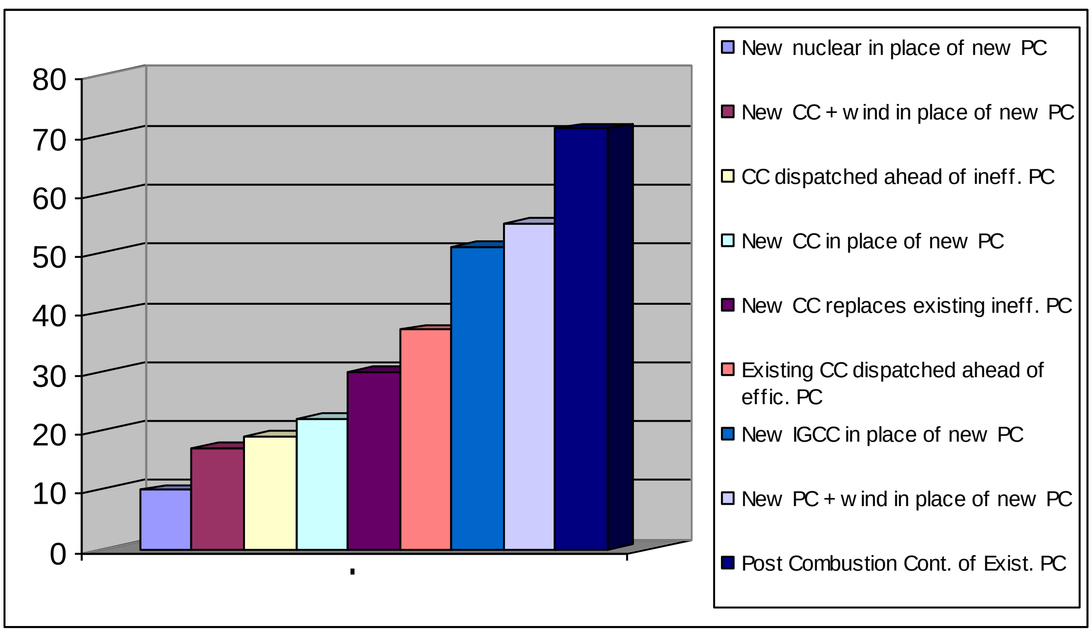
- Integrated Coal Gasification Combined Cycle (IGCC)
- Chilled ammonia or amine-based post-combustion CO_2 capture applicable to existing and new coal generators
- Oxy-combustion, a pre-combustion process applicable to existing and new pulverized coal generators.

In all cases the costs of CO_2 capture reflect only a portion of the costs of CO_2 control. Additional costs for compression, piping and storage in geologic formations underground (sequestration) must also be included. For purposes of this analysis, optimistic low estimates of the costs of sequestration have been applied but the effects of sequestration on CO_2 emissions were not included.

Figure 5.7 illustrates the relative costs of various generation technologies aimed at avoiding or abating CO_2 emissions. The costs of CO_2 avoidance or abatement are shown in dollars per ton avoided or abated relative to the costs of existing or new pulverized coal generators. They reflect the \$/ton CO_2 allowance price that would equate the cost of the two options shown at a typical baseload capacity factor of 85%.

As shown in Figure 5.7, the least costly way to avoid CO_2 emissions appears to be through the use of new nuclear plant additions in place of new pulverized coal additions. However, this measure would at most be applicable to the additional capacity needed to meet growth and even a doubling of the current 100 GW nuclear fleet with remaining capacity additions supplied by gas reduces 2030 CO_2 emissions to a level 80% above the cap in the High CO_2 scenario. In addition, the socio-political ramifications of doubling the nuclear fleet in the U.S. makes that outcome appear highly unlikely.

Figure 5.7 Relative Costs of CO_2 Avoidance/Abatement in the Electric Industry - \$2007/Ton



Source: B&V Analysis

After nuclear generator additions in place of new pulverized coal additions, the next five least expensive options for avoiding CO_2 emissions include the use of gas fueled combined cycle generation. These estimates of dollars per ton of avoided CO_2 are before any increase in gas price associated with higher gas use in the U.S. At the point where the increased price of gas makes these gas fueled measures as costly as the use of IGCC or even as costly as the use of pre- or post-combustion control of existing coal generators, the demand for natural gas to avoid or abate CO_2 emissions will level off. Based on current estimates of the costs of IGCC or retrofit capture and storage of CO_2, the increased demand for gas will subside at a price of about 11 to 14 dollars per MBtu for natural gas.

5.2.4 Combined Electric Scenarios

Using projections of natural gas and coal prices from AEO 2007, along with B&V estimates of the relative capital costs and efficiencies of new super-critical pulverized coal and gas fueled combined cycle plants in B&V's generation expansion and production cost model yields projections of significant coal fueled generator additions as described in Section 3 of this report. Inherent in this Reference Case scenario is an increase in natural gas use for electric generation of from 6.1 quadrillion Btu in 2006 to 6.9 quadrillion Btu in 2030.

In the Low and High CO_2 emission scenarios, new coal fueled generators are not viable and the demand for natural gas to serve the electric industry is much higher, growing at a rate between 4 and 5 times the gas consumption growth rate in the Reference Case and resulting in 2030 gas consumption of 21 quadrillion Btu. While such an increase in gas consumption will almost surely result in an increase in natural gas prices above that forecast in the AEO 2007, the ultimate impact will be an increase in the price of electricity because the use of coal for electric generation will have to decrease from 2006 levels in order to meet the CO_2 cap implicit in the High CO_2 scenario. While nuclear and renewable generation may increase beyond the forecasts in the AEO 2007, especially in a carbon constrained world, the growth in demand for natural gas to fuel electric generation will still be multiple times the 1% growth rate inherent in the Reference Case.

Figures C.1 through C.10 in Appendix C illustrate the impact of gas supply, R&C technology and potential CO_2 controls on the Reference Case forecast of electric generation by fuel type, CO_2 emissions from the electric sector and finally on the demand for natural gas by the electric sector. It is in the context of these alternative baseline futures that the increased direct use of natural gas must be viewed. Initially, the gas supply and technology scenarios were combined recognizing that end use technology levels affect R&C demand for natural gas and that the supply affects the price. Because high and low gas supply levels affect the price of gas to both the R&C end users and to the electric industry, the mix of gas versus electric end use demands was not anticipated to be affected by the increased or decreased price of natural gas in the low and high supply scenarios. Consequently, only the technology assumptions were used to adjust the demand for gas and electricity by the R&C customers in the combined Gas Supply and Technology scenarios. Furthermore, the CO_2 Constrained scenarios were assumed to initially impact only the electric industry and specifically, the fuel type to be avoided by increased direct use of natural gas. The impacts on gas price of the Constrained CO_2 scenarios were used to alter the forecast value of the gas saved by the increased direct use of natural gas.

5.3 Introduction to Metrics

Three metrics have been selected in the study to capture the impact on the U.S. energy market from the increased direct use of natural gas for R&C applications rather than for power generation.

- Energy consumption as measured in Quadrillion Btu
- Total energy cost as measured in 2005 dollars
- CO_2 Emissions as measured in tons

5.3.1 Energy Consumption (Quadrillion Btu)

Energy consumption measures the increase in natural gas demand from direct use in R&C applications and the accompanying decrease in electricity demand for these applications. The energy consumption impact of the decrease in electricity demand is measured by the decreased demand for the source fuels that are used to produce the electricity – mainly coal and natural gas. The resulting net impact on U.S. energy consumption from increased gas demand and decreased electricity demand is captured with this metric.

5.3.2 Energy Costs ($2005)

Energy cost measures the increased cost from increased natural gas demand for direct use in R&C applications, the decrease in energy cost associated with the corresponding decrease in electricity demand and the resulting net impact on the total energy cost in the U.S. The different price environments in the various scenarios modeled and the change in energy consumption drive the cost of the energy that is captured with this metric.

5.3.3 CO_2 Emissions (Tons)

CO_2 emissions capture net impact on carbon dioxide emissions from increased gas demand and decreased electricity demand. The fuel mix for electricity generation in the scenarios being examined influences the CO_2 emissions with the greatest CO_2 emissions impacts being seen in the scenarios with a high percentage of coal in the electricity generation mix.

5.4 Analysis of Impact of Direct Use of Natural Gas for R&C Applications

The analysis examines the impact of increased direct gas use for R&C applications that can utilize either electricity or natural gas, within the defined scenarios. A portion of the demand for electricity for R&C applications has been assumed to be shifted to gas. The study analysis assumes a 7% shift of the total electric load for R&C applications to natural gas. Given current technology, the residential applications considered are space heating, water heating, cooking and clothes drying. Commercial applications are space heating, water heating and cooking. Capital costs related to replacing electric appliances with natural gas appliances have not been considered in this analysis but the cost of gas connections (not including inside the house retrofitting) have been considered. In addition, the annual amortized costs of avoided generating plants have been included in the analysis.

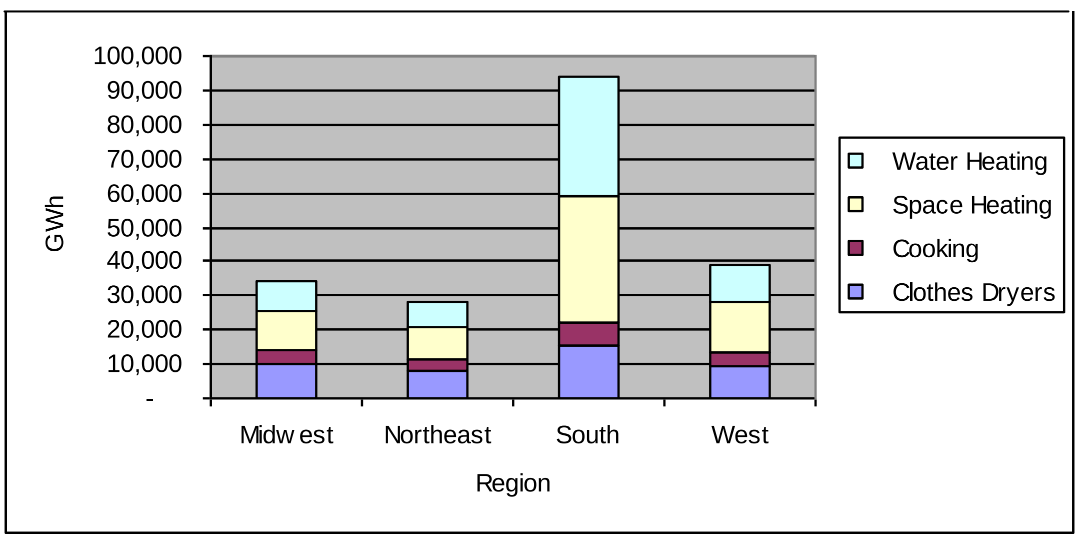
The analysis entailed the following steps in order to examine the impact on the U.S. energy market from the increased direct use of natural gas for R&C applications:

- Quantify the increased natural gas demand from shifting a percentage of current electric demand for switchable R&C applications to natural gas
- Quantify corresponding decreased electricity demand for R&C applications
- Identify and quantify the primary energy used to produced the avoided electricity consumption
- Quantify the net impact on primary energy requirements in the U.S. from a shift in R&C demand from electricity to natural gas
- Quantify the net impact on primary energy costs and CO_2 emissions

The impact of increased direct gas use varies by region of the county - lower in regions that already use gas for the majority of space and water heating and higher in states in which the penetration of gas space and water heat could expand. Regional savings also depend on the mix of R&C to industrial loads which vary by region.

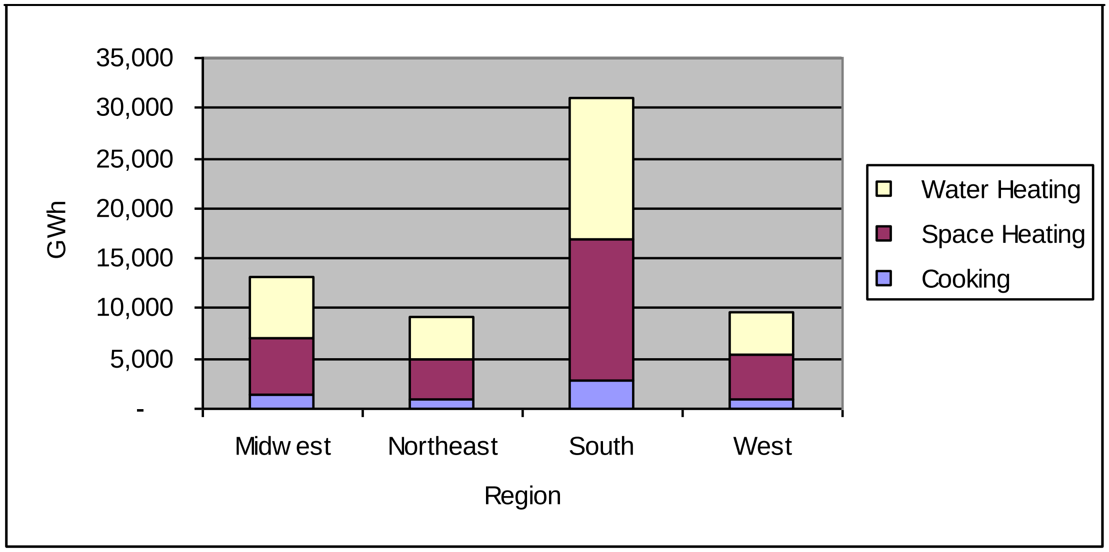
To reflect these regional differences, this study estimated the potential for shifting heating load by census region based on R&C heating energy consumption surveys conducted by U.S. DOE. Estimates of other switchable loads by region were based on the allocation of households by census region assuming a high correlation between household and cooking and clothes drying loads. Figures 5.8 and 5.9 reflect forecasts of regional R&C electricity use reductions by end use and census region for the sample year 2012 assuming 7% of the total electric load is now natural gas R&C appliance load.

Figure 5.8: Regional Residential Electricity Reduction by End Use (2012)



Source: EIA, B&V Analysis

Figure 5.9: Regional Commercial Electricity Reduction by End Use (2012)



Source: EIA, B&V Analysis

Given forecasts of electric demand savings by census region, B&V computed these savings as a percentage of total electric use and applied these percentage savings to each of the electric markets in these census regions. The generation expansion and production cost model was then used for each region along with the regional fuel prices and production of existing generators to estimate electric production by fuel type with and without the shift of switchable electric energy to direct gas use. The models were used to add economic capacity additions and estimate fuel used and emissions produced with and without increased direct gas use. By analyzing electricity shifts on a regional basis, we reflect savings in gas or coal generation depending on the percentage of time gas and coal are the marginal generators in each region and we reflect this in forecast of gas and/or coal energy savings and emissions reductions.

By developing regional generation expansion and production cost simulation models, B&V was also able to simulate the reaction of the electric industry to moderate and stringent versions of proposed CO_2 emissions regulation – scenarios not considered by EIA. This modeling ability is especially important since as shown above, the demand for gas by the electric industry is expected to be quite high if the U.S. implements even moderate versions of proposed CO_2 constraints. In such scenarios, the benefits of reduced gas use are more important than ever.

5.4.1 Reference Case Scenario Analysis

Electricity serves a significant portion of the R&C demand for energy. As shown in Appendix D (Figure D.1), electricity currently serves 39% of residential demand for energy and is projected to serve an even larger proportion of 47% by 2030.[23]

Within the commercial sector, electricity currently serves about half of the demand for energy and is projected to grow to serve 57% of the demand by 2030 as shown in Appendix D (Figure D.2).[24]

Between 22-25% of the residential consumption of electricity is for applications that can be served directly by natural gas. Appendix D (Figure D.3) shows the growing demand for electricity for space heating, water heating, cooking and clothes drying as well as for other applications that cannot readily switch between electricity and natural gas.

Between 6-9% of commercial consumption of electricity is, similarly, for applications that can be served directly by natural gas as shown in Appendix D (Figure D.4).

5.4.1.1 Impact of Increase in Gas Demand and Decreased Demand for Electricity for R&C Applications

The shift from electric demand drives an increase in gas demand of 0.2-1.0 quadrillion Btu or 0.5-2.7 Bcf/day in 2030 depending on the percentage of switchable demand that is shifted to natural gas. Since there are losses along the natural gas value chain from production to the residence or commercial building, the total increase in gas demand is greater than the increase at the site of use. As elaborated in various studies including AGF's Real Energy Efficiency Study[25] and AGA's Energy Efficiency Study[26], analyzing the real energy needs represents a more comprehensive assessment of the implications of total energy consumption, the impacts on CO_2 emissions and energy costs. Real energy takes into account the losses along the value chain in addition to the end use consumption in contrast to site energy that measures end use energy consumption alone. A real energy factor is, therefore, incorporated to account for the losses along the natural gas value chain in order to estimate the true increase in gas demand. As estimated by the AGA, the losses associated with natural gas during extraction, processing and transportation result in a cumulative efficiency of 90.5% or a real (source) energy factor of 1.1 for residential applications as shown in Figure 5.10.[27] While the earlier AGA study assigned 31.8% conversion efficiency to the electricity produced with natural gas, a 51% efficiency is more applicable to today's efficient combined cycle generators reducing the source energy conversion factor to 2.3 in place of the 3.7 shown in Figure 5.10. This study assumed that the source energy factors for commercial applications would be the same as for residential applications.

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[23] EIA, AEO 2007
[24] EIA, AEO 2007
[25] "Public Policy and Real Energy Efficiency, Assessing the effects of Federal policies on energy consumption and the environment", October 2005, AGF.
[26] "Energy Efficiency, Economic and Environmental Comparison of Natural Gas, Electric, and Oil Services in Residences", May 1999, AGA.
[27] "Source Energy and Emission Factors for Residential Energy Consumption", August 2000, AGA.

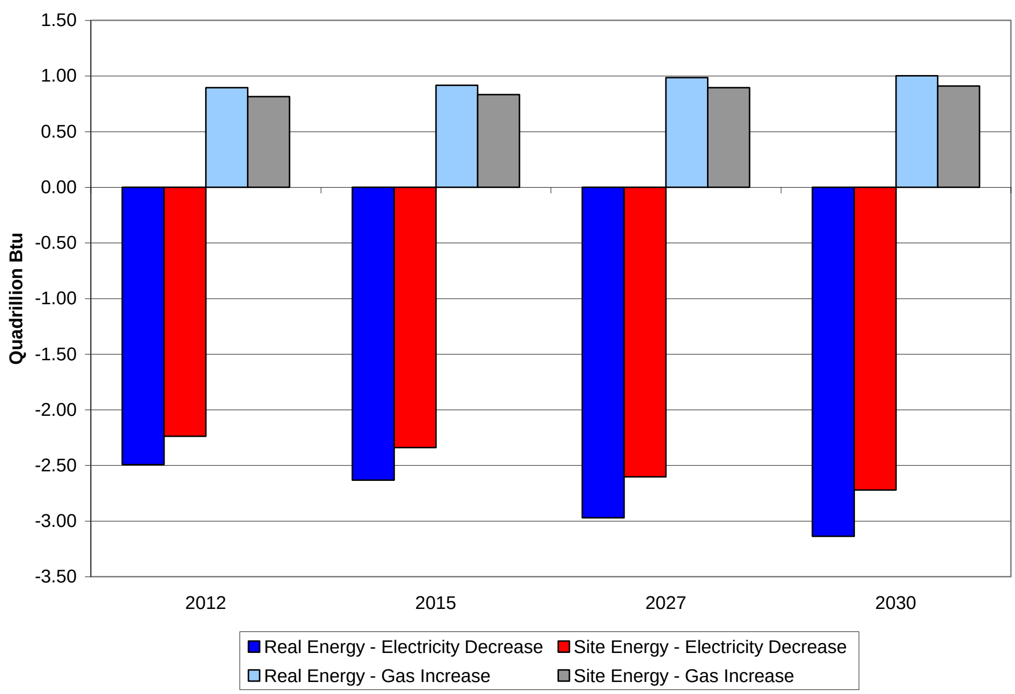
Figure 5.10: Efficiency of Energy Delivered to the Home

Energy Type	Extraction	Processing	Transportation	Conversion	Distribution	Cumulative Efficiency	Source Energy Conversion Factor
Natural Gas	96.8%	97.6%	97.3%	100.0%	98.4%	90.5%	1.1
Oil	96.8%	90.2%	98.4%	100.0%	99.8%	85.7%	1.2
Electricity							
Coal-Based	99.4%	90.0%	97.5%	33.4%	92.0%	26.8%	3.7
Oil-Based	96.8%	90.2%	98.4%	32.5%	92.0%	25.7%	3.9
Natural Gas-Based	96.8%	97.6%	97.3%	31.8%	92.0%	26.9%	3.7

Source: "Source Energy and Emission Factors for Residential Energy Consumption", August 2000, AGA.

Figure 5.11 shows a side by side comparison of the natural gas increase and electricity decrease from shifting 7% of the total electric load for R&C applications to natural gas. The forecasts use the Reference Case assumptions previously described and include the additional approximate 10% needed to account for energy losses associated with the extraction, processing, transportation and distribution of electric energy. The efficiency losses in the conversion of natural gas and coal to electricity are accounted for in the assumed efficiency expressed as heat rate of the generators dispatched to meet load. From Figure 5.11, the reduction in real energy consumption begins at 2.5 quadrillion Btu in 2012 and increases to nearly 3 quadrillion Btu by 2027 and 2030 because 152 GW of new coal generation is assumed to be built in the Reference Case, coal generation on the margin in the electric sector increases through time and constitutes nearly 70% of the electric energy saved by 2030.

Figure 5.11: Impact on Energy Consumption with Increased Direct Use of Gas

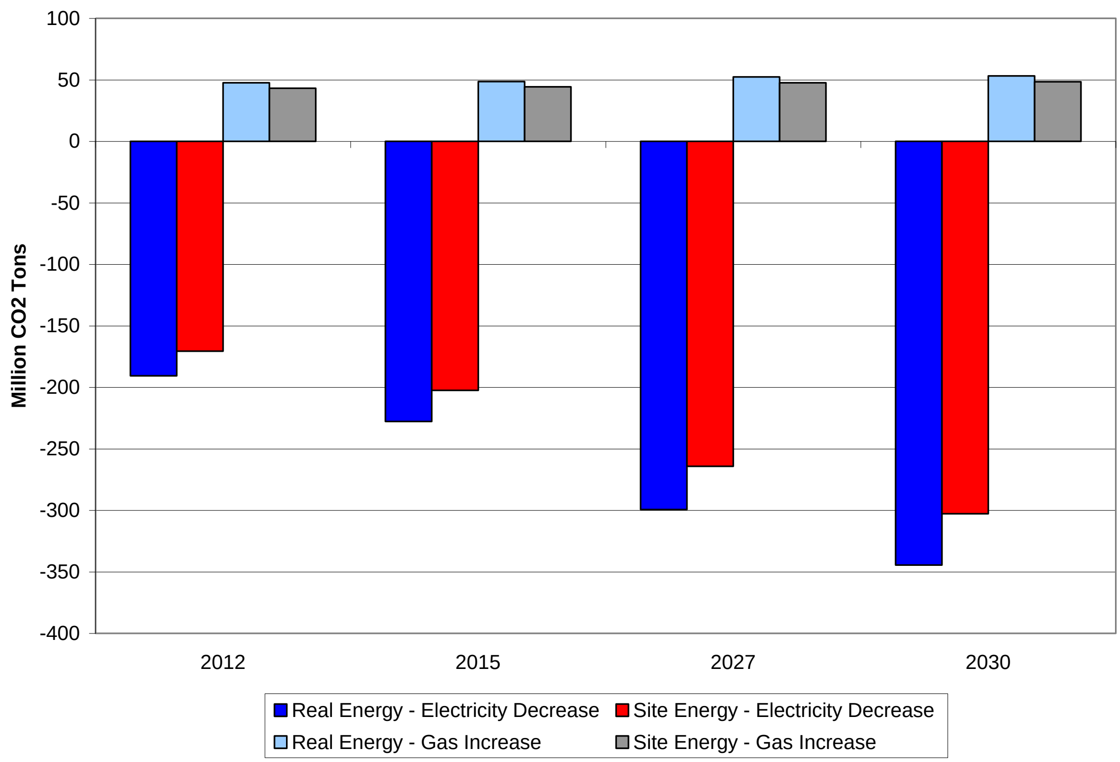


Source: EIA, B&V Analysis

The impacts on the CO_2 emissions are shown corresponding to the real energy increase in natural gas demand and decrease in electricity demand. As shown in Figure 5.12, the corresponding increase in CO_2 emissions for real energy is 53 million tons of CO_2 a year in 2030 for the increase in gas demand impact; while the reduction due to reduced electricity demand is over 250 million tons. [28]

In the reference case, the significant amounts of coal on the margin drive the results of larger CO_2 reductions than would normally be associated with increased savings in gas used to generate electricity.

Figure 5.12: Impact on Emissions with Increased Direct Use of Natural Gas



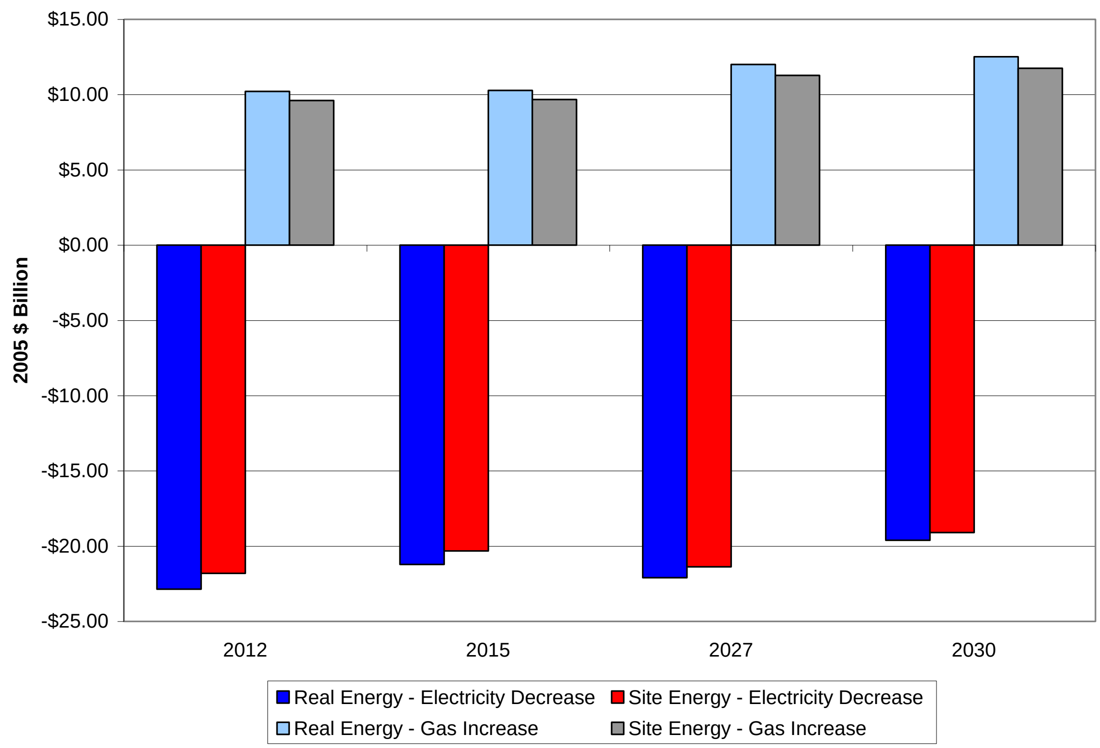
Source: EIA, B&V Analysis

[28] Assumes an emissions coefficient of 117.98 pounds CO_2 per Million Btu of natural gas based on emissions coefficients from EIA (http://www.eia.doe.gov/oiaf/1605/coefficients.html). Assumes 2204.6 pounds per ton of CO_2.

The increase in energy costs from increased gas demand can be seen below. The additional costs are small when compared to the savings from a decrease in electricity demand. The cost of the primary fuel use (coal and gas) saved by reduced electricity generation as a result of increased direct gas use is shown in Figure 5.13. From Figure 5.13 the trend is initially downward and then upward in the value of reduced fuel use from almost $23 billion in 2012 to $22 billion in 2015 and over $25 billion in 2030 for real energy. This trend in the value of fuel saved is directly a function of the offsetting impacts of an increasing proportion of electric fuel savings from lower priced coal through time and growth in the amount of energy assumed to switch from electricity to natural gas.

In the Reference Case, B&V estimates that approximately 24 GW of new coal generating capacity and 29 GW of new gas fueled generating capacity could be saved by shifting 50% of switchable R&C loads to direct gas use.

Figure 5.13: Impact on Energy Costs with Increased Direct Use of Natural Gas



Source: EIA, B&V Analysis

5.4.1.2 Impact of Increased Gas Infrastructure and Decreased Electric Infrastructure Requirements

Additional Gas Connection Costs

In addition to increased natural gas costs associated with the increased use of natural gas for R&C applications, consumers will undoubtedly need to pay for additional gas connections to enable the increased use. Estimates of the gas connection costs associated with the greater direct gas use were based on AEO 2007 forecasts of the number of households in the U.S. as well as an assumed percentage of 39% of households that do not currently have a gas connection.[29] The number of households in the U.S. is projected to be 124 million by 2012 increasing to 147 million by 2030. The assumptions used for increased gas use for R&C applications was applied to the 39% of the 2012 households that do not have access to gas.

In addition to the assumptions regarding households needing connections, an estimated $1,078 per connection was applied to estimate the costs associated with new gas connections. The estimate of $1,078 per connection ($2005) was based on data collected by AGF weighted by Census region. This did not include retrofit costs within the home, since we anticipate that customers will make retrofit decisions when appliances wear out and a portion of the increased gas usage will be with new homes where there is no retrofit costs. Finally, the annual investments in new gas connections were assumed to be amortized by the supplying LDC using a 14.5% amortization factor that accounts for depreciation, interest, return, insurance and taxes for property financed over 20 years.

Based on the assumptions described above, estimates of the additional natural gas connection costs range from $3.5 billion in 2012 to $4.2 billion in 2030.

Avoided Electric Generation Capacity Costs

The direct use of gas at the R&C level avoids overall electric consumption and the need for additional electric capacity. B&V's model of the US electric system was used to forecast the avoided capacity requirements which were then estimated to produce a forecast of avoided electric capacity costs. In the Reference Case for the electric industry, both coal and gas fueled capacity construction was avoided. As discussed earlier in this report, the avoided cost of gas generation capacity in $2005 is $790/kW. The avoided cost of coal was estimated at $2,380/kW ($2005).

[29] Residential Natural Gas Market Survey 2005, AGA and American Housing Survey, U.S. Census Bureau

Avoided capacity is forecast to range from 63 to 80 GW[30] in 2030, depending on the scenario, and avoided investment costs are forecast to range from $49 billion to $122 billion. The highest investment savings occur in the Reference Case with the avoidance of coal fueled capacity. Application of a 14.5% amortization factor to the gas capacity investment and a 13.2% amortization factor to the avoided coal generation investment yielded a range of annual avoided generation capacity costs of $7.2 to $16.5 billion in 2030. Figure 5.14 shows the net forecast of increased natural gas connection costs and avoided electric generating capacity costs.

Figure 5.14: Avoided Capacity Costs – Billion $2005

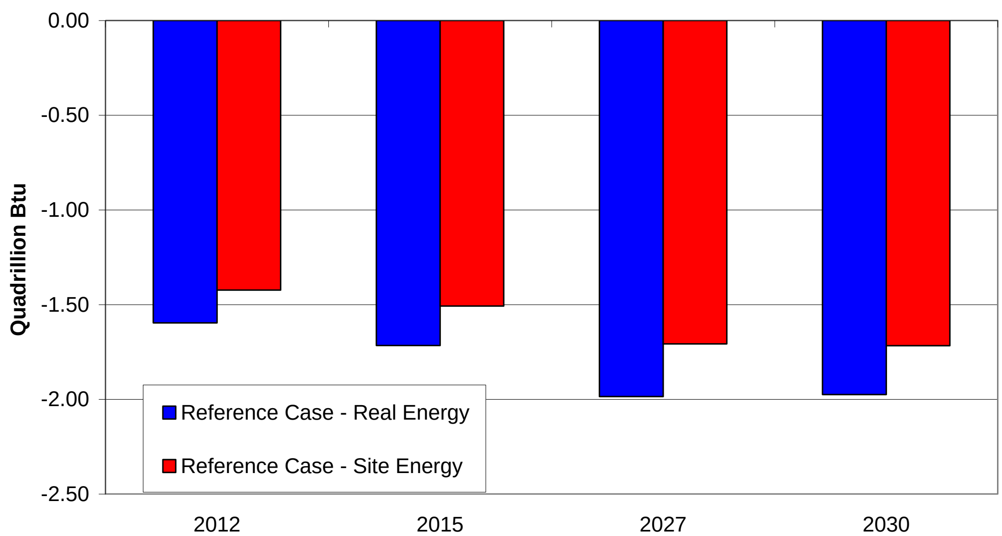
	2012	2015	2027	2030
Reference Case	$7.31	$8.09	$11.71	$12.33
Gas Supply Lower/Low Tech/High CO2	$3.41	$3.64	$4.75	$5.03
Gas Supply Lower/High Tech/High CO2	$1.86	$2.00	$2.76	$3.04
Gas Supply Higher/Low Tech/Low CO2	$2.51	$2.69	$3.60	$3.89
Gas Supply Higher/High Tech/Low CO2	$1.86	$2.00	$2.76	$3.04

[30] The estimate of avoided electric generating capacity in GW was based on simplified assumptions of the demand for switchable uses at the time of peak demand for supplying electric utilities. A detailed analysis of residential and commercial electric load patterns by end use coincident with electric system peaks would be required to better estimate the avoided generation capacity. Such a detailed analysis should be included in subsequent investigations.

5.4.1.3 Net Impact from Increased Direct Use of Natural Gas for R&C Applications

The net impact on energy consumption from the increase in natural gas demand for direct use in R&C applications and the corresponding decrease in electricity demand is shown in Figure 5.15.

Figure 5.15: Decrease in Energy Consumption – Real & Site Energy

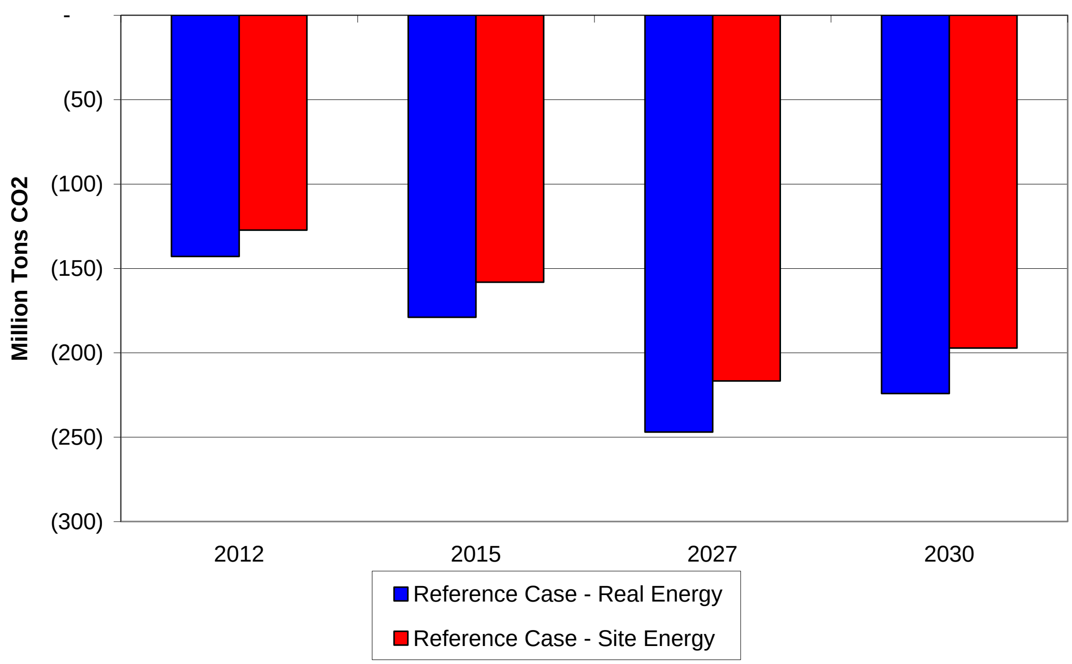


Source: EIA, B&V Analysis

Since the conversion of primary energy into electricity is relatively inefficient, the decrease in electricity demand produces a larger decrease in primary energy consumption than the increase in gas demand that is created by its increased direct use for R&C applications. The net site energy consumption in the Reference Case analysis is reduced by about 1.75 quadrillion Btu in 2030 with a real energy decrease in consumption of about 2 quadrillion Btu which are 11% and 13%, respectively, of R&C and power generation natural gas consumption.

The net impact on emissions in the Reference Case assumptions is shown in Figure 5.16. CO_2 emissions are lowered by over 200 million tons in 2030 driven by the decrease in energy consumption caused by decrease in electricity demand. Further, the decrease in electricity demand causes a drop in the level of coal fired generation with its accompanying significant decrease in CO_2 emissions.

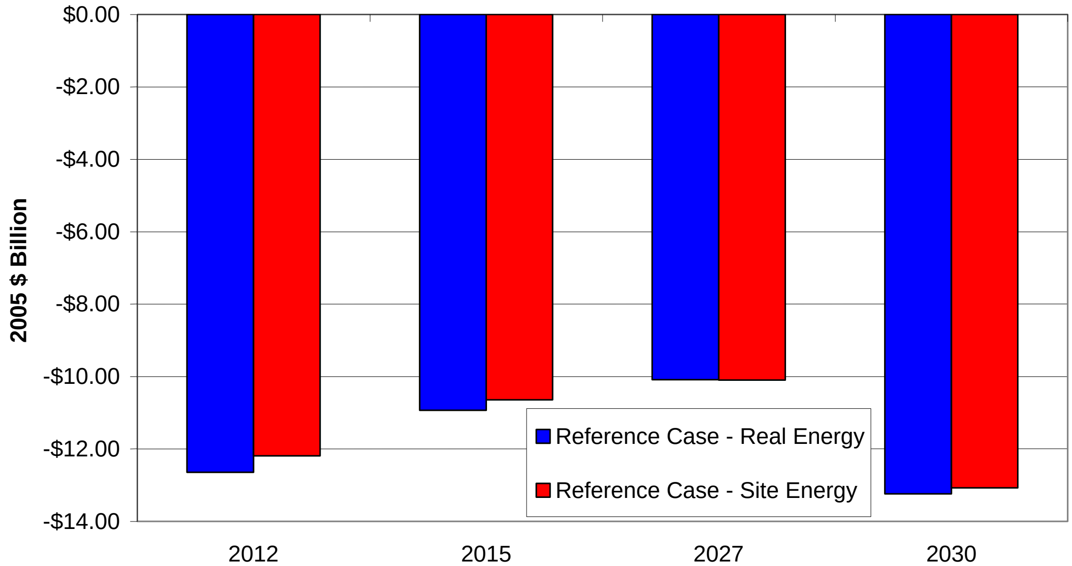
Figure 5.16: Decrease in Emissions – Real & Site Energy



Source: EIA, B&V Analysis

The net impact on the total energy cost in the United States is shown in Figure 5.17. Both site energy and real energy impacts are added to the annual infrastructure cost impacts to indicate a reduction in total energy costs of about $13 billion in 2030. Because primary energy savings become increasingly coal fueled between 2012 and 2027, the net cost of increased gas use for R&C applications minus the avoided cost of generation fuel, which is largely coal, results in a reduction in net energy cost savings for the years 2015 and 2027. By 2030, however, the increase in the cost of coal in the AEO 2007 forecast reduces the proportion of coal fueled generator additions and increases the net savings in the cost of primary energy. As will be shown in subsequent sections, the lack of growth in coal fueled generation in the CO_2 constrained scenarios results in the avoidance of primarily gas for electric generation and no dip in the value of total energy savings.

Figure 5.17: Decrease in Energy Costs – Real & Site Energy and Infrastructure Costs



Source: EIA, B&V Analysis

5.4.2 Scenario Analysis

5.4.2.1 Natural Gas Supply Lower Environment

This scenario captures a natural gas supply environment driven by low supply of natural gas and high CO_2 emissions restrictions. Lower supply, driven by lower LNG imports or reduced production levels than in the Reference Case, creates a tighter supply environment for natural gas. On the demand side, high restrictions on CO_2 emissions create increased demand for natural gas to meet electric demand growth and to replace coal-fired electricity generation. The combination of lower supply and high demand creates a high priced and volatile market for natural gas. Two technology scenarios are modeled within this natural gas supply lower environment – 2006 (low) Technology and High Technology. These two assumptions indicate higher consumption of electricity for switchable R&C applications and lower consumption of electricity for switchable R&C applications, respectively, due to differences in the efficiencies of the applications.

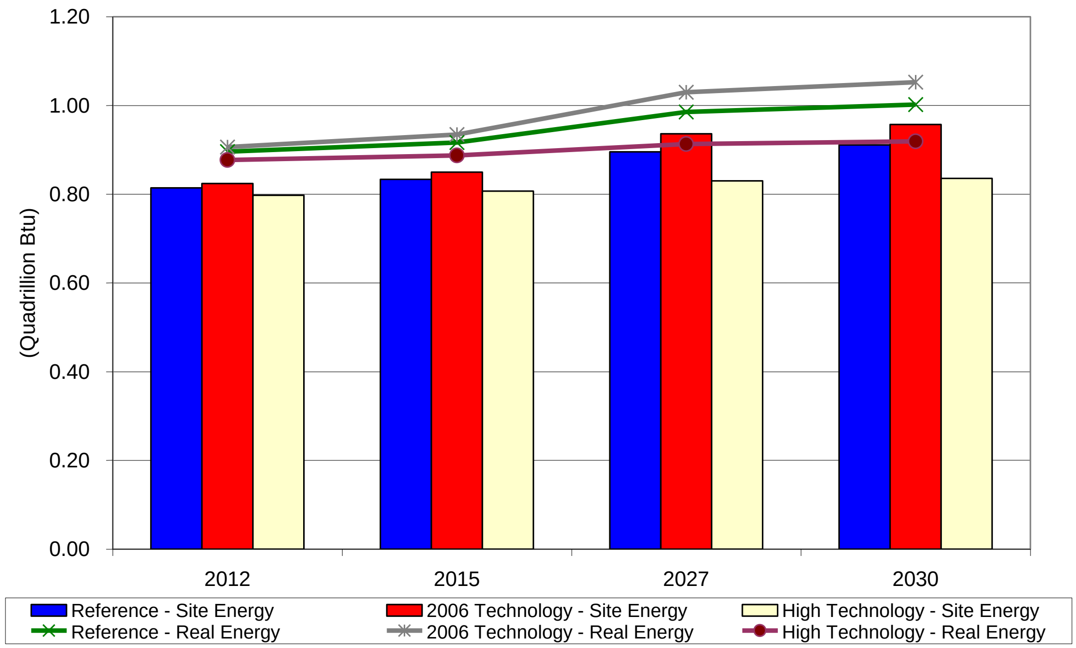
5.4.2.2 Natural Gas Supply Higher Environment

This scenario captures a natural gas environment driven by high supply of natural gas and low CO_2 emissions restrictions. Natural gas supply driven by greater LNG imports or increased production is higher than in the Reference Case creating a higher supply environment for natural gas. On the demand side, low restrictions on CO_2 emissions create decreased demand for natural gas as cheaper coal-fired electric generation plants are built. The combination of higher supply and low demand creates a low priced market for natural gas. Two technology scenarios are modeled within this natural gas supply environment – 2006 Technology and High Technology. These two assumptions indicate higher consumption of electricity for switchable R&C applications and lower consumption of electricity for switchable R&C applications, respectively, due to differences in the efficiencies of the applications.

5.4.2.3 Impact of Increased Gas Demand

The increase in gas demand in the site energy technology scenarios ranges from 0.84 to 0.91 quadrillion Btu in 2030. The corresponding real energy increase in gas demand ranges from 0.92 to 1 quadrillion Btu as shown in Figure 5.18.

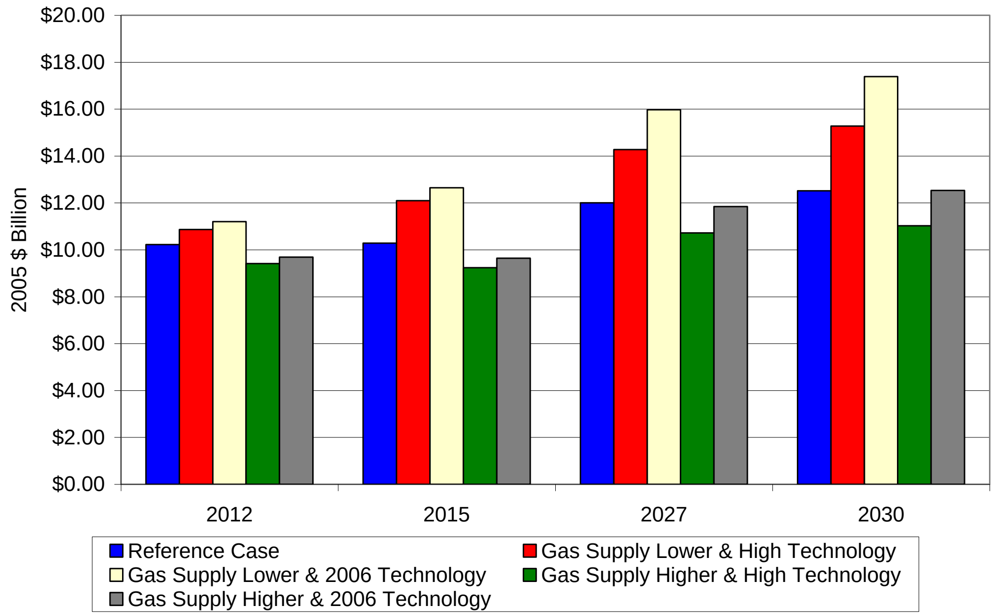
Figure 5.18: Increase in Gas Demand for Switchable R&C Applications



Source: EIA, B&V Analysis

The increase in energy cost associated with increased gas demand for direct use in R&C applications is shown in Figure 5.19. The expected increase in energy cost ranges from $11 to $17.4 billion in 2030.

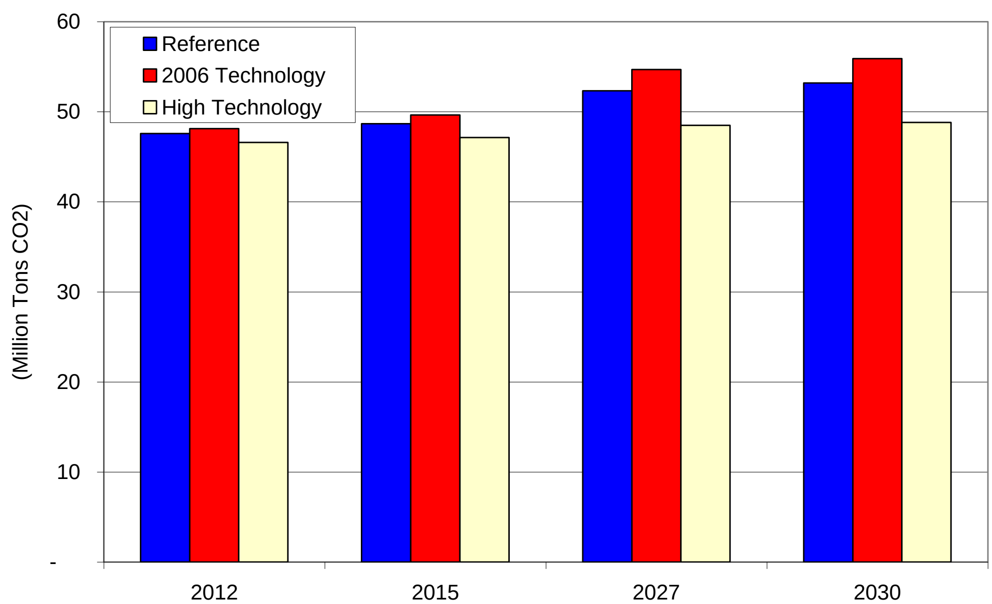
Figure 5.19: Increase in Energy Costs from Increased Gas Demand – Real Energy and Infrastructure



Source: EIA, B&V Analysis

Increase in emissions corresponding to the real energy increase in gas demand assuming the increase in direct gas use ranges from 49 to 53 million tons of CO_2 per year in 2030 as shown in Figure 5.20.

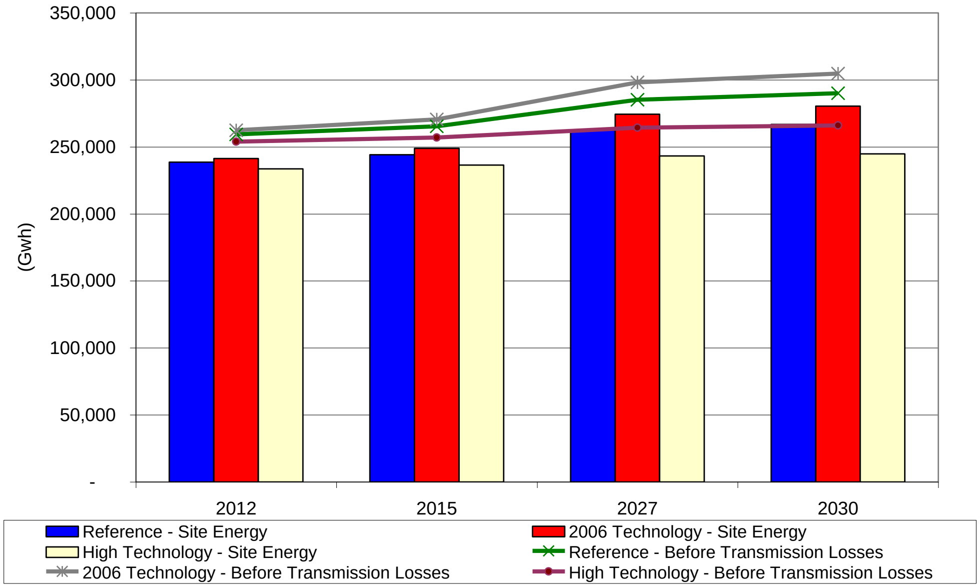
Figure 5.20: Increase in Emissions from Increased Gas Demand – Technology Scenarios



Source: EIA, B&V Analysis

Decrease in electricity consumption ranges from 245,000 to 280,000 GWh of delivered energy or 266,000 to 305,000 GWh of electricity before transmission losses in 2030 as shown in Figure 5.21.

Figure 5.21: Decrease in Electricity Consumption for Switchable R&C Applications

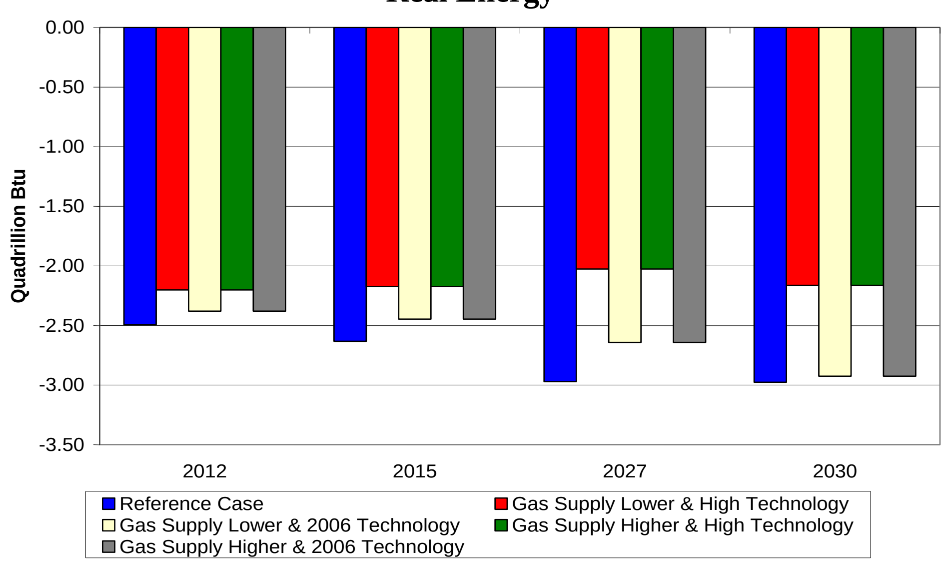


Source: EIA, B&V Analysis

5.4.2.4 Impact of Decrease in Electricity Demand

The decrease in electric demand under each of the five scenarios results in a range in real primary energy savings of from 2.2 to 2.9 quadrillion Btu in 2030 as shown in Figure 5.22. For all but the Reference Case, this primary energy savings is natural gas.

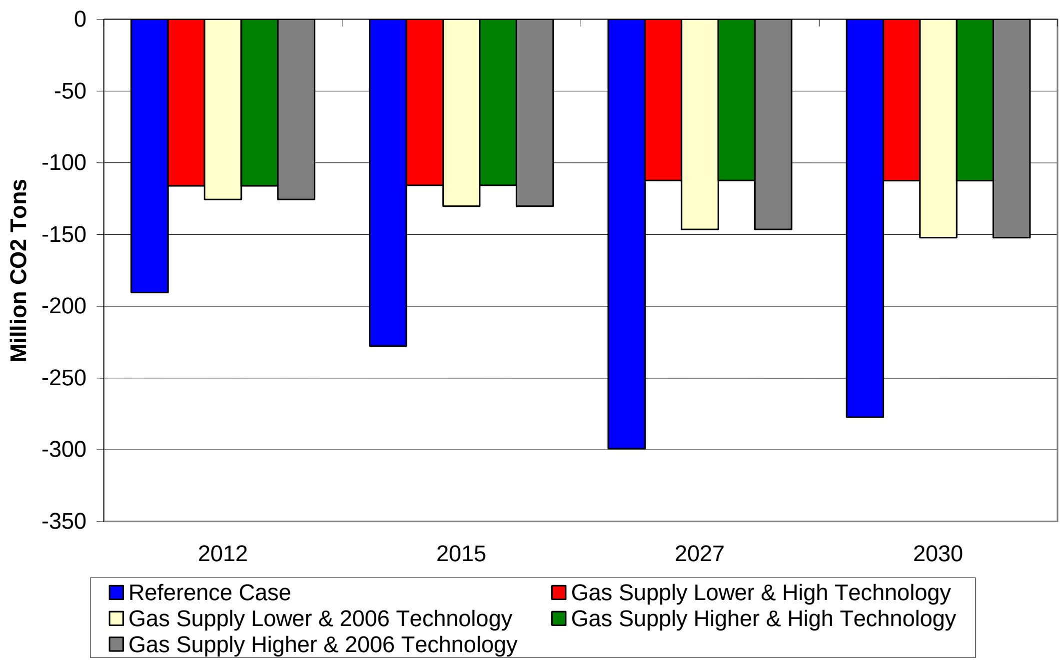
Figure 5.22: Electric Generation Impact of Decrease in Electricity Demand – Real Energy



Source: EIA, B&V Analysis

Corresponding forecasts of CO_2 reductions resulting from reduced electric consumption are shown in Figure 5.23. As is the case with primary energy savings, reduced CO_2 emissions are associated with reduced gas use for electric generation except in the Reference Case where they result largely from decreased coal consumption, especially in the latter part of the forecast period. The range in reduced CO_2 emissions is from 120 to 278 million tons in 2030.

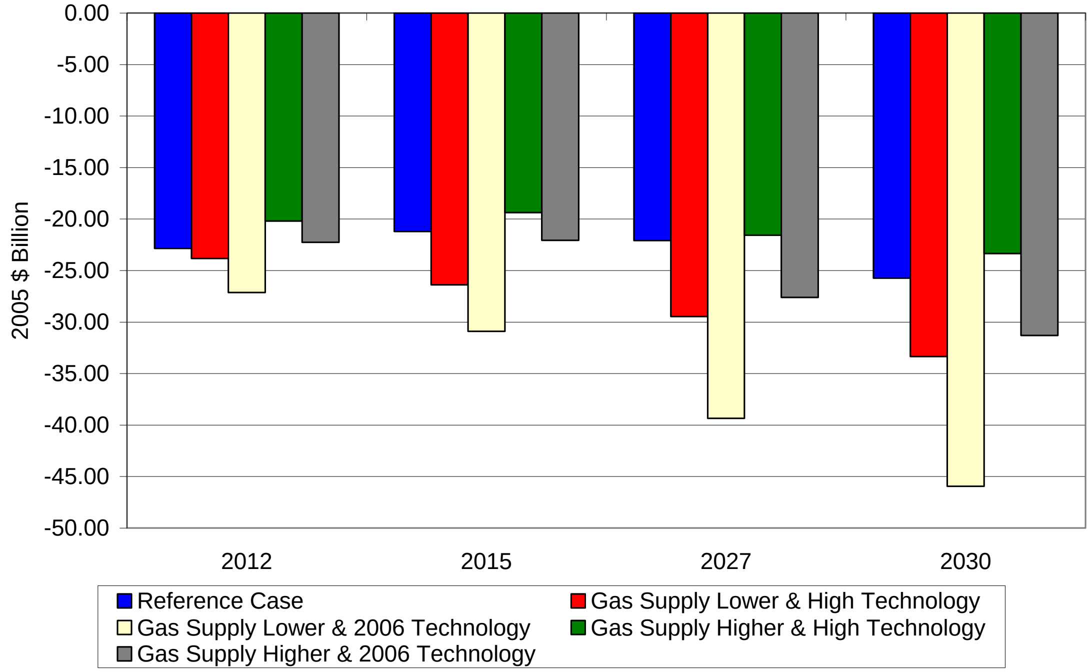
Figure 5.23: CO_2 Emissions Impact of Decrease in Electricity Demand – Real Energy



Source: EIA, B&V Analysis

The impact on the cost of primary energy saved as a result of decreased electric generation is shown in Figure 5.24. The value of the avoided primary energy is maximized in the –Gas Supply Lower & 2006 Technology – High CO_2 scenario as a result of the high cost of gas being applied to higher gas savings under the 2006 Technology scenario. The range in the value of primary energy savings from reduced electricity use is from $23 billion to almost $46 billion in 2030.

Figure 5.24: Energy Cost Impact of Decrease in Electricity Demand – Real Energy and Infrastructure Costs

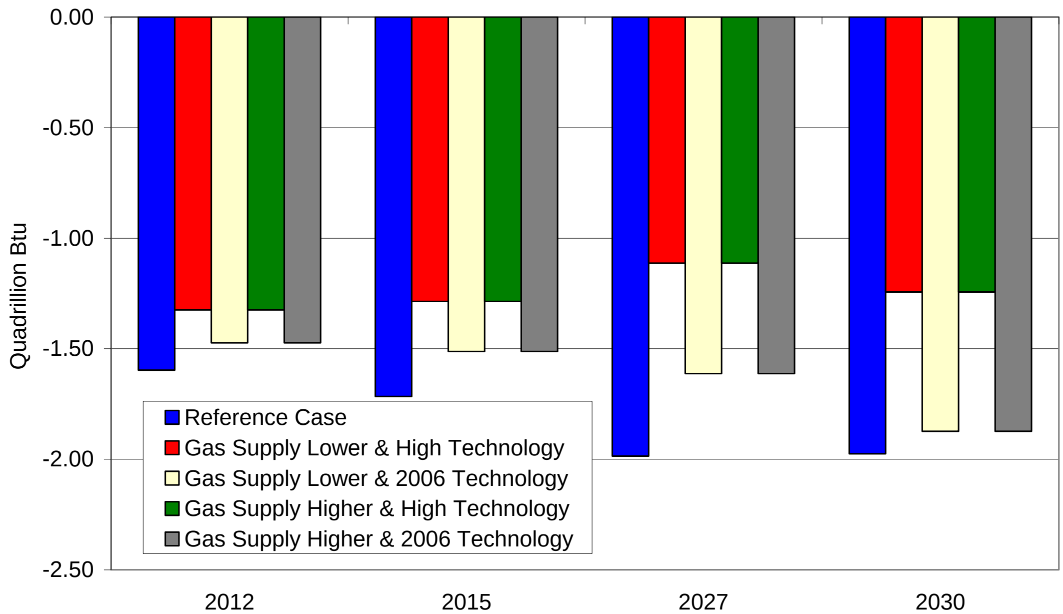


Source: EIA, B&V Analysis

5.4.2.5 Net Impact from Increased Direct Use of Natural Gas for R&C Applications in the Five Scenarios Analyzed

The net impact on energy consumption from the increased direct use of natural gas for R&C applications instead of for power generations is shown in Figure 5.25. As the analysis indicates, there is a net drop in the total energy consumption in the United States that ranges from 1.25 quadrillion Btu to almost 2 quadrillion Btu in 2030. The greater efficiency of natural gas when compared to electricity is the contributing factor that drives the expected savings in energy.

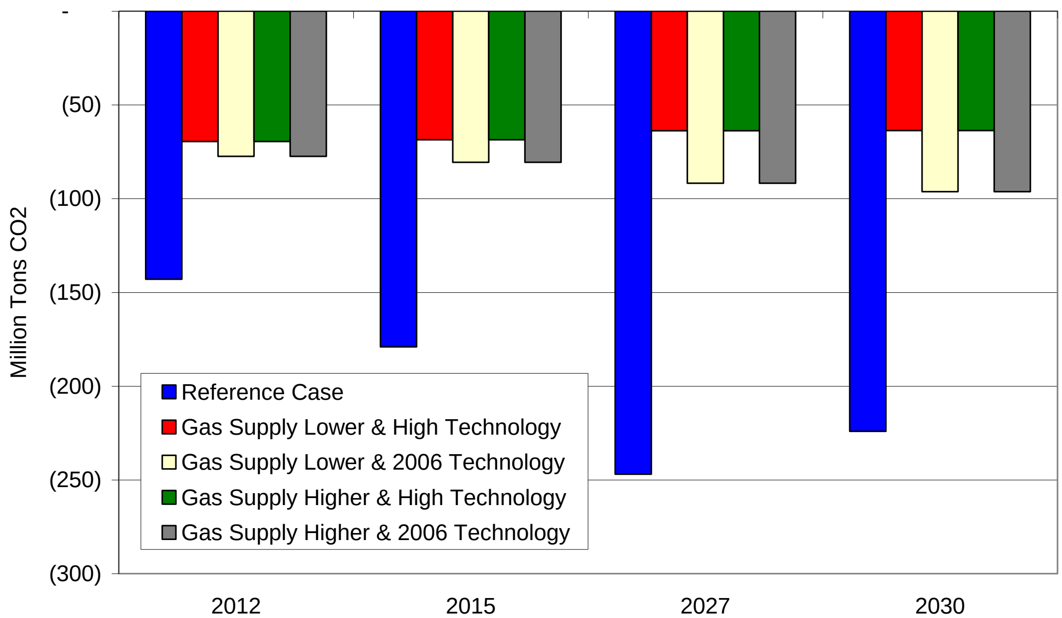
Figure 5.25: Decrease in Energy Consumption – Real Energy



Source: EIA, B&V Analysis

The net impact on CO_2 emissions from the increased direct use of natural gas for R&C applications is shown in Figure 5.26. In all the scenarios considered, there is a net decrease in the total CO_2 emissions from the increased use of natural gas for R&C applications rather than for power generation. The Reference Case shows the largest decrease in emissions of almost 200 million tons of CO_2 driven by a decrease in coal fired generation. The decrease in CO_2 emissions in the other scenarios ranges from about 60 to almost 100 million tons of CO_2.

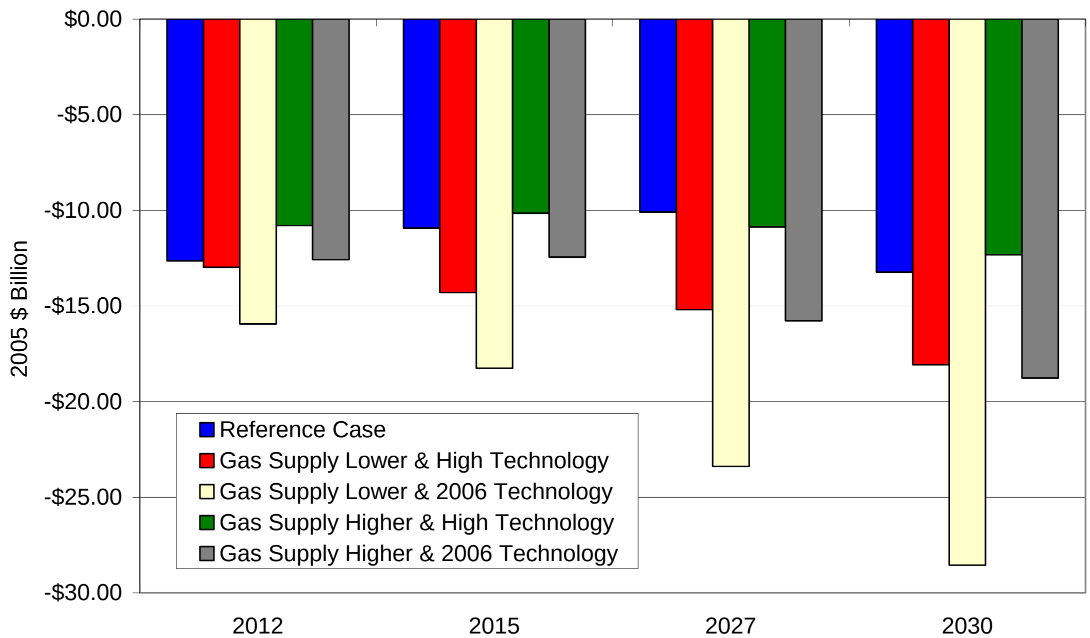
Figure 5.26: Decrease in Emissions – Real Energy



Source: EIA, B&V Analysis

The net impact on the total energy costs for the United States is shown in Figure 5.27. In all the scenarios considered, there is a net decrease in the total energy costs by 2030. The savings in energy costs range from $12 billion to almost $29 billion in 2030. The more constrained the natural gas market, the greater the savings from shifting from electricity to direct gas use for R&C applications.

Figure 5.27: Decrease in Energy Costs – Real Energy and Infrastructure Costs



Source: EIA, B&V Analysis

5.5 Summary of Analysis

5.5.1 Impact on Energy Consumption & Energy Cost

The increased direct use of natural gas for R&C applications rather than from power generation is expected to decrease the total energy consumption in the United States. Within the scenarios considered, when assuming 7% of the total electric load served by electric R&C applications is now served by the direct use of natural gas, the analysis indicates that the energy savings can range from 1.25-2.00 quadrillion Btu per year in 2030.

Reference scenario – In the absence of restrictions on CO_2 emissions, there is a greater proportion of coal fired plants in the electric generation mix. Coal is on the margin in this scenario and gets displaced when the increased direct use of gas for R&C applications decreases electricity demand. Although the consumption of natural gas use is increased on a net basis in the outer years, the net impact on overall energy consumption and energy cost is negative taking both natural gas and coal into account.

Carbon constrained scenarios – With restrictions on the total level of CO_2 emissions, natural gas is on the margin and gets displaced when the increased direct use of gas for R&C applications decreases electricity demand. Greater direct use of natural gas applications decreases gas consumption as well as energy costs in a market where natural gas supply is lower as well as more expensive.

In the natural gas supply lower environment where CO_2 restrictions match the levels proposed by Lieberman-Warner, the value of the reduction in energy costs is significant and in the range of $18 to almost $29 billion dollars in the year 2030.

Figures 5.28, 5.29, and 5.30 show a summary of the decrease in energy consumption, energy cost and CO_2 emissions in the scenarios considered.

Figure 5.28: Summary Analysis Results for Energy Consumption, 2030

	Site Energy			**Real Energy**		
	Energy Consumption (quadrillion Btu)			*Energy Consumption (quadrillion Btu)*		
	Gas	Electricity	Net Impact	Gas	Electricity	Net Impact
Scenario 1: Baseline Case	0.9	-2.6	-1.7	1.0	-3.0	-2.0
Scenario 2: Gas Supply Lower						
Scenario 2a: Gas Supply Lower & High Technology	0.8	-2.0	-1.2	0.9	-2.2	-1.2
Scenario 2b: Gas Supply Lower & 2006 Technology	1.0	-2.7	-1.7	1.1	-2.9	-1.9
Scenario 3: Gas Supply Higher						
Scenario 3a: Gas Supply Higher & High Technology	0.8	-2.0	-1.2	0.9	-2.2	-1.2
Scenario 3b: Gas Supply Higher & 2006 Technology	1.0	-2.7	-1.7	1.1	-2.9	-1.9

Source: EIA, B&V Analysis

Figure 5.29: Summary Analysis Results for Energy Costs, 2030

	Site Energy – Energy Cost (2005$)			Real Energy – Energy Cost (2005$)		
	Gas	Electricity	Net Impact	Gas	Electricity	Net Impact
Scenario 1: Baseline Case	11.8	-24.8	-13.1	12.5	-25.8	-13.2
Scenario 2: Gas Supply Lower						
Scenario 2a: Gas Supply Lower & High Technology	14.3	-31.2	-17.0	15.3	-33.3	-18.1
Scenario 2b: Gas Supply Lower & 2006 Technology	16.2	-43.0	-26.8	17.4	-45.9	-28.6
Scenario 3: Gas Supply Higher						
Scenario 3a: Gas Supply Higher & High Technology	10.4	-22.0	-11.6	11.0	-23.3	-12.3
Scenario 3b: Gas Supply Higher & 2006 Technology	11.8	-29.4	-17.7	12.5	-31.3	-18.8

Source: EIA, B&V Analysis

Figure 5.30: Summary Analysis Results for Carbon Emissions, 2030

	Site Energy – Carbon Emissions (million tons)			Real Energy – Carbon Emissions (million tons)		
	Gas	Electricity	Net Impact	Gas	Electricity	Net Impact
Scenario 1: Baseline Case	48.4	-245.6	-197.2	53.2	-277.3	-224.1
Scenario 2: Gas Supply Lower						
Scenario 2a: Gas Supply Lower & High Technology	44.4	-103.3	-58.9	48.8	-112.5	-63.7
Scenario 2b: Gas Supply Lower & 2006 Technology	50.8	-139.7	-88.9	55.9	-152.2	-96.3
Scenario 3: Gas Supply Higher						
Scenario 3a: Gas Supply Higher & High Technology	44.4	-103.3	-58.9	48.8	-112.5	-63.7
Scenario 3b: Gas Supply Higher & 2006 Technology	50.8	-139.7	-88.9	55.9	-152.2	-96.3

Source: EIA, B&V Analysis

5.5.2 Impact on CO_2 Emissions

The decrease in energy consumption also drives a decrease in the CO_2 emissions over time in all the scenarios considered. The greatest reduction in CO_2 emissions from a greater use of natural gas to serve R&C applications is in the Reference Case that assumes no restrictions on CO_2 emissions and hence a greater proportion of coal fired plants in the electric generation mix. When the electricity demand is decreased, the amount of coal fired generation is first decreased with a resulting net decrease in CO_2 emissions of almost 200 million tons in 2030. The CO_2 emissions constrained scenarios also show a decrease in CO_2 emissions from switching to greater direct use of gas in R&C applications.

Appendix A

Net Impact Analysis

Analysis of Net Impact of Increased Direct Use of Natural Gas for R&C Applications

Reference Case

		2012	2015	2027	2030
Energy Consumption					
Increase in Gas Demand for R&C Applications					
	Site Energy	0.81	0.83	0.90	0.91
	Real Energy	0.90	0.92	0.99	1.00
Change in Energy for Electric Generation					
Change in Coal Consumption					
	Site Energy	-0.99	-1.48	-2.38	-2.02
	Real Energy	-1.13	-1.70	-2.73	-2.32
Change in Gas Consumption					
	Site Energy	-1.25	-0.86	-0.22	-0.60
	Real Energy	-1.36	-0.94	-0.24	-0.66
Change in Energy for Electric Generation					
	Site Energy	-2.24	-2.34	-2.60	-2.63
	Real Energy	-2.49	-2.63	-2.97	-2.98
Net Impact on Energy Consumption					
Change in Gas Consumption					
	Site Energy	**-0.43**	**-0.03**	**0.67**	**0.31**
	Real Energy	**-0.46**	**-0.02**	**0.74**	**0.35**
Change in Energy Consumption					
	Site Energy	**-1.42**	**-1.51**	**-1.71**	**-1.72**
	Real Energy	**-1.60**	**-1.72**	**-1.99**	**-1.98**
Emissions (million tons CO2)					
Increased Gas Demand for R&C					
	Site Energy	43	44	48	48
	Real Energy	48	49	52	53
Change in Energy for Electric Generation	Site Energy	-171	-203	-264	-246
Real Energy Adjustment for Coal		-14	-21	-34	-29
Real Energy Adjustment for Gas		-6	-4	-1	-3
Change in Energy for Electric Generation	Real Energy	-191	-228	-299	-277
Net Change in Emissions					
	Site Energy	**(127)**	**(158)**	**(217)**	**(197)**
	Real Energy	**(143)**	**(179)**	**(247)**	**(224)**
Energy Cost					
Average Delivered Price ($/MMBtu)	Gas	7.51	7.28	8.06	8.33
	Coal	1.64	1.60	1.59	1.63
Change in Energy Cost (2005 $ billions)	**Site Energy**	**-$12.19**	**-$10.64**	**-$10.10**	**-$13.07**
	Real Energy	**-$12.64**	**-$10.93**	**-$10.09**	**-$13.24**

Analysis of Net Impact of Increased Direct Use of Natural Gas for R&C Applications

Gas Supply Lower & High Technology

		2012	2015	2027	2030
Energy Consumption					
Increase in Gas Demand for R&C Applications					
	Site Energy	0.80	0.81	0.83	0.84
	Real Energy	0.88	0.89	0.91	0.92
Change in Energy for Electric Generation					
Change in Coal Consumption					
	Site Energy	0.00	0.00	0.00	0.00
	Real Energy	0.00	0.00	0.00	0.00
Change in Gas Consumption					
	Site Energy	-2.02	-2.00	-1.86	-1.99
	Real Energy	-2.20	-2.17	-2.03	-2.16
Change in Energy for Electric Generation					
	Site Energy	-2.02	-2.00	-1.86	-1.99
	Real Energy	-2.20	-2.17	-2.03	-2.16
Net Impact on Energy Consumption					
Change in Gas Consumption					
	Site Energy	**-1.23**	**-1.19**	**-1.03**	**-1.15**
	Real Energy	**-1.32**	**-1.29**	**-1.11**	**-1.24**
Change in Energy Consumption					
	Site Energy	**-1.23**	**-1.19**	**-1.03**	**-1.15**
	Real Energy	**-1.32**	**-1.29**	**-1.11**	**-1.24**
Emissions (million tons CO2)					
Increased Gas Demand for R&C					
	Site Energy	42	43	44	44
	Real Energy	47	47	48	49
Change in Energy for Electric Generation	Site Energy	-107	-106	-104	-103
Real Energy Adjustment for Coal		0	0	0	0
Real Energy Adjustment for Gas		-9	-9	-9	-9
Change in Energy for Electric Generation	Real Energy	-116	-116	-112	-113
Net Change in Emissions					
	Site Energy	**(64)**	**(64)**	**(60)**	**(59)**
	Real Energy	**(70)**	**(69)**	**(64)**	**(64)**
Energy Cost					
Average Delivered Price ($/MMBtu)	Gas	8.40	9.56	11.17	12.08
	Coal				
Change in Energy Cost (2005 $ billions)	**Site Energy**	**-$12.16**	**-$13.40**	**-$14.30**	**-$16.97**
	Real Energy	**-$12.98**	**-$14.30**	**-$15.20**	**-$18.07**

Analysis of Net Impact of Increased Direct Use of Natural Gas for R&C Applications

Gas Supply Lower & 2006 Technology

		2012	2015	2027	2030
Energy Consumption					
Increase in Gas Demand for R&C Applications					
	Site Energy	0.82	0.85	0.94	0.96
	Real Energy	0.91	0.93	1.03	1.05
Change in Energy for Electric Generation					
Change in Coal Consumption					
	Site Energy	0.00	0.00	0.00	0.00
	Real Energy	0.00	0.00	0.00	0.00
Change in Gas Consumption					
	Site Energy	-2.19	-2.25	-2.43	-2.69
	Real Energy	-2.38	-2.45	-2.64	-2.93
Change in Energy for Electric Generation					
	Site Energy	-2.19	-2.25	-2.43	-2.69
	Real Energy	-2.38	-2.45	-2.64	-2.93
Net Impact on Energy Consumption					
Change in Gas Consumption					
	Site Energy	**-1.36**	**-1.40**	**-1.49**	**-1.73**
	Real Energy	**-1.47**	**-1.51**	**-1.61**	**-1.87**
Change in Energy Consumption					
	Site Energy	**-1.36**	**-1.40**	**-1.49**	**-1.73**
	Real Energy	**-1.47**	**-1.51**	**-1.61**	**-1.87**
Emissions (million tons CO2)					
Increased Gas Demand for R&C					
	Site Energy	44	45	50	51
	Real Energy	48	50	55	56
Change in Energy for Electric Generation	Site Energy	-115	-120	-135	-140
Real Energy Adjustment for Coal		0	0	0	0
Real Energy Adjustment for Gas		-10	-10	-11	-13
Change in Energy for Electric Generation	Real Energy	-126	-130	-146	-152
Net Change in Emissions					
	Site Energy	**(72)**	**(75)**	**(85)**	**(89)**
	Real Energy	**(77)**	**(81)**	**(92)**	**(96)**
Energy Cost					
Average Delivered Price ($/MMBtu)	Gas	8.51	9.66	11.56	12.56
	Coal				
Change in Energy Cost (2005 $ billions)	**Site Energy**	**-$15.01**	**-$17.17**	**-$22.00**	**-$26.79**
	Real Energy	**-$15.94**	**-$18.25**	**-$23.39**	**-$28.56**

Analysis of Net Impact of Increased Direct Use of Natural Gas for R&C Applications

Gas Supply Higher & High Technology

		2012	2015	2027	2030
Energy Consumption					
Increase in Gas Demand for R&C Applications					
	Site Energy	0.80	0.81	0.83	0.84
	Real Energy	0.88	0.89	0.91	0.92
Change in Energy for Electric Generation					
Change in Coal Consumption					
	Site Energy	0.00	0.00	0.00	0.00
	Real Energy	0.00	0.00	0.00	0.00
Change in Gas Consumption					
	Site Energy	-2.02	-2.00	-1.86	-1.99
	Real Energy	-2.20	-2.17	-2.03	-2.16
Change in Energy for Electric Generation					
	Site Energy	-2.02	-2.00	-1.86	-1.99
	Real Energy	-2.20	-2.17	-2.03	-2.16
Net Impact on Energy Consumption					
Change in Gas Consumption					
	Site Energy	**-1.23**	**-1.19**	**-1.03**	**-1.15**
	Real Energy	**-1.32**	**-1.29**	**-1.11**	**-1.24**
Change in Energy Consumption					
	Site Energy	**-1.23**	**-1.19**	**-1.03**	**-1.15**
	Real Energy	**-1.32**	**-1.29**	**-1.11**	**-1.24**
Emissions (million tons CO2)					
Increased Gas Demand for R&C					
	Site Energy	42	43	44	44
	Real Energy	47	47	48	49
Change in Energy for Electric Generation	Site Energy	-107	-106	-104	-103
Real Energy Adjustment for Coal		0	0	0	0
Real Energy Adjustment for Gas		-9	-9	-9	-9
Change in Energy for Electric Generation	Real Energy	-116	-116	-112	-113
Net Change in Emissions					
	Site Energy	**(64)**	**(64)**	**(60)**	**(59)**
	Real Energy	**(70)**	**(69)**	**(64)**	**(64)**
Energy Cost					
Average Delivered Price ($/MMBtu)	Gas	6.75	6.33	7.28	7.46
	Coal				
Change in Energy Cost (2005 $ billions)	**Site Energy**	**-$10.13**	**-$9.55**	**-$10.28**	**-$11.64**
	Real Energy	**-$10.80**	**-$10.15**	**-$10.87**	**-$12.32**

Analysis of Net Impact of Increased Direct Use of Natural Gas for R&C Applications

Gas Supply Higher & 2006 Technology

		2012	2015	2027	2030
Energy Consumption					
Increase in Gas Demand for R&C Applications					
	Site Energy	0.82	0.85	0.94	0.96
	Real Energy	0.91	0.93	1.03	1.05
Change in Energy for Electric Generation					
Change in Coal Consumption					
	Site Energy	0.00	0.00	0.00	0.00
	Real Energy	0.00	0.00	0.00	0.00
Change in Gas Consumption					
	Site Energy	-2.19	-2.25	-2.43	-2.69
	Real Energy	-2.38	-2.45	-2.64	-2.93
Change in Energy for Electric Generation					
	Site Energy	-2.19	-2.25	-2.43	-2.69
	Real Energy	-2.38	-2.45	-2.64	-2.93
Net Impact on Energy Consumption					
Change in Gas Consumption					
	Site Energy	**-1.36**	**-1.40**	**-1.49**	**-1.73**
	Real Energy	**-1.47**	**-1.51**	**-1.61**	**-1.87**
Change in Energy Consumption					
	Site Energy	**-1.36**	**-1.40**	**-1.49**	**-1.73**
	Real Energy	**-1.47**	**-1.51**	**-1.61**	**-1.87**
Emissions (million tons CO2)					
Increased Gas Demand for R&C					
	Site Energy	44	45	50	51
	Real Energy	48	50	55	56
Change in Energy for Electric Generation	Site Energy	-115	-120	-135	-140
Real Energy Adjustment for Coal		0	0	0	0
Real Energy Adjustment for Gas		-10	-10	-11	-13
Change in Energy for Electric Generation	Real Energy	-126	-130	-146	-152
Net Change in Emissions					
	Site Energy	**(72)**	**(75)**	**(85)**	**(89)**
	Real Energy	**(77)**	**(81)**	**(92)**	**(96)**
Energy Cost					
Average Delivered Price ($/MMBtu)	Gas	6.83	6.45	7.55	7.94
	Coal				
Change in Energy Cost (2005 $ billions)	**Site Energy**	**-$11.83**	**-$11.72**	**-$14.87**	**-$17.66**
	Real Energy	**-$12.58**	**-$12.44**	**-$15.78**	**-$18.77**

Appendix B

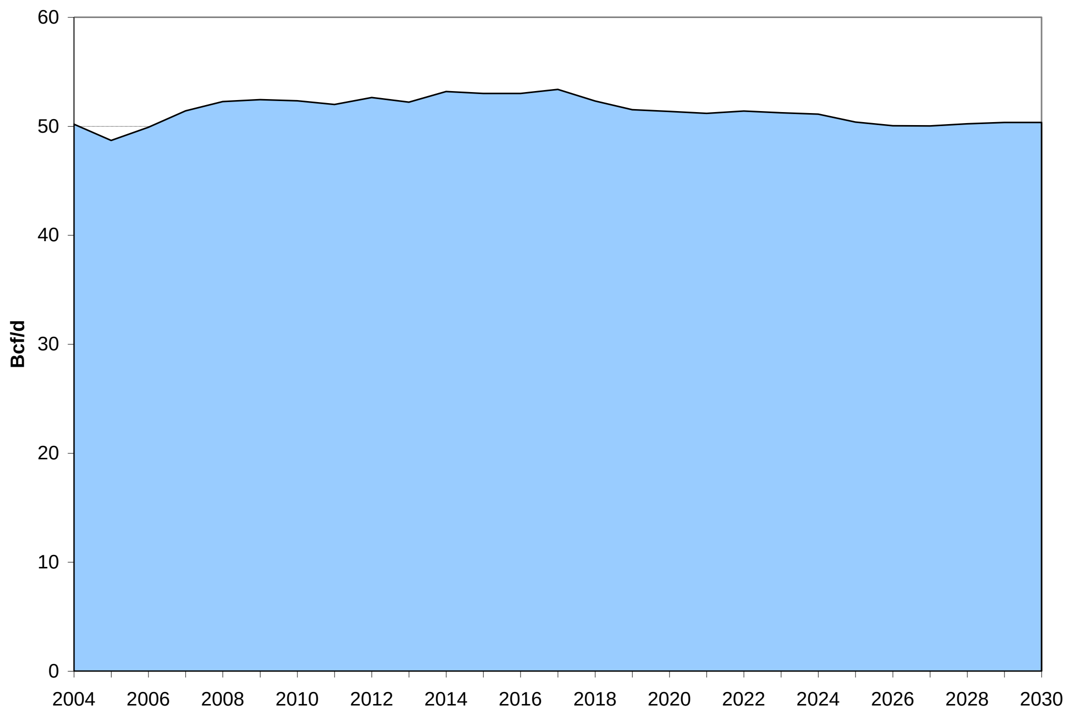
Overview of Natural Gas Supply

As the natural gas market has become increasingly volatile since 2000, natural gas prices have climbed and greater focus has been placed on the competitiveness of the different applications where natural gas is used. This section provides an overview of natural gas supply in North America as a means to provide a background for the study.

U.S. Total Production

Natural gas production in the lower 48, including both onshore and offshore production, is expected to peak in 2017 at 53.4 Bcf/day as shown in Figure B.1. Within the lower 48 production, about 50% of projected U.S. natural gas production will be from unconventional sources in 2030. From this projection, the outlook of supply for the U.S. greatly depends on the ability to develop new unconventional gas sources.

Figure B.1: Lower 48 Total Production

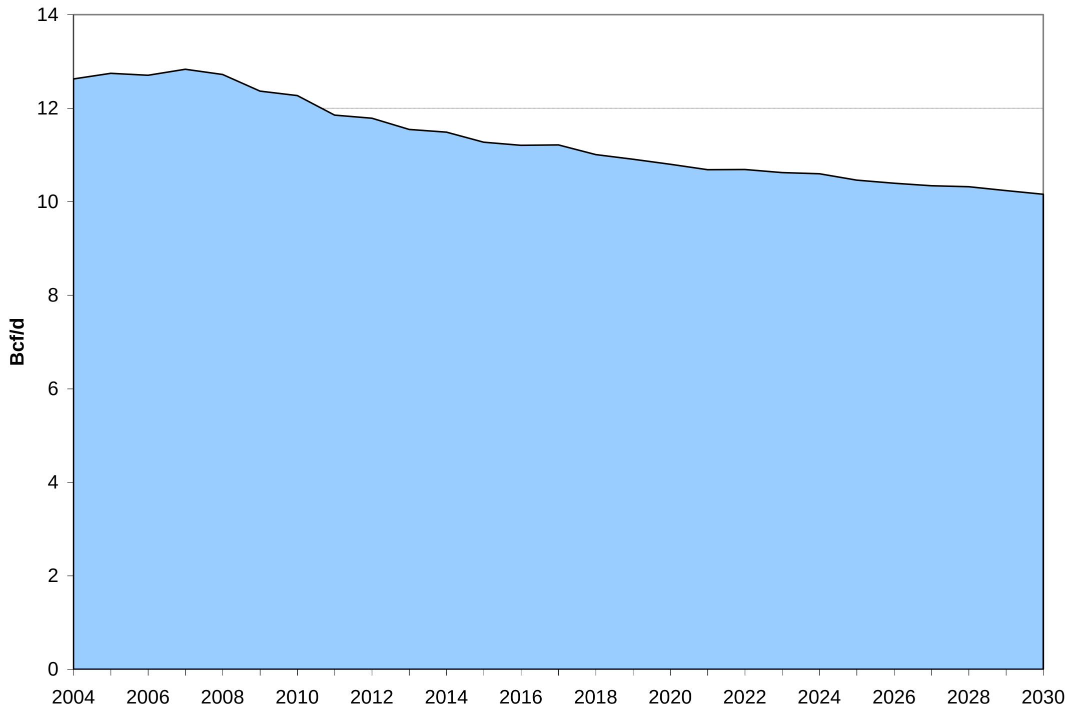


Source: EIA, AEO 2007

Gulf Coast Region

Gulf Coast natural gas production is projected to decline steadily going forward. Peak production is forecasted to be 12.8 Bcf/day in 2007 with a decrease thereafter to 10.2 Bcf/day in 2030 as shown in Figure B.2. Even though about half of all onshore undiscovered gas resources are located in the Gulf Coast region and Alaska, many of these resources are not economically or environmentally viable to extract at the current or projected natural gas prices. Although the Gulf Coast production is projected to be lower than Rockies production by 2008, the Gulf Coast region has more developed infrastructure and thus fewer constraints on take away capacity than the Rockies region.

Figure B.2: Gulf Coast Production

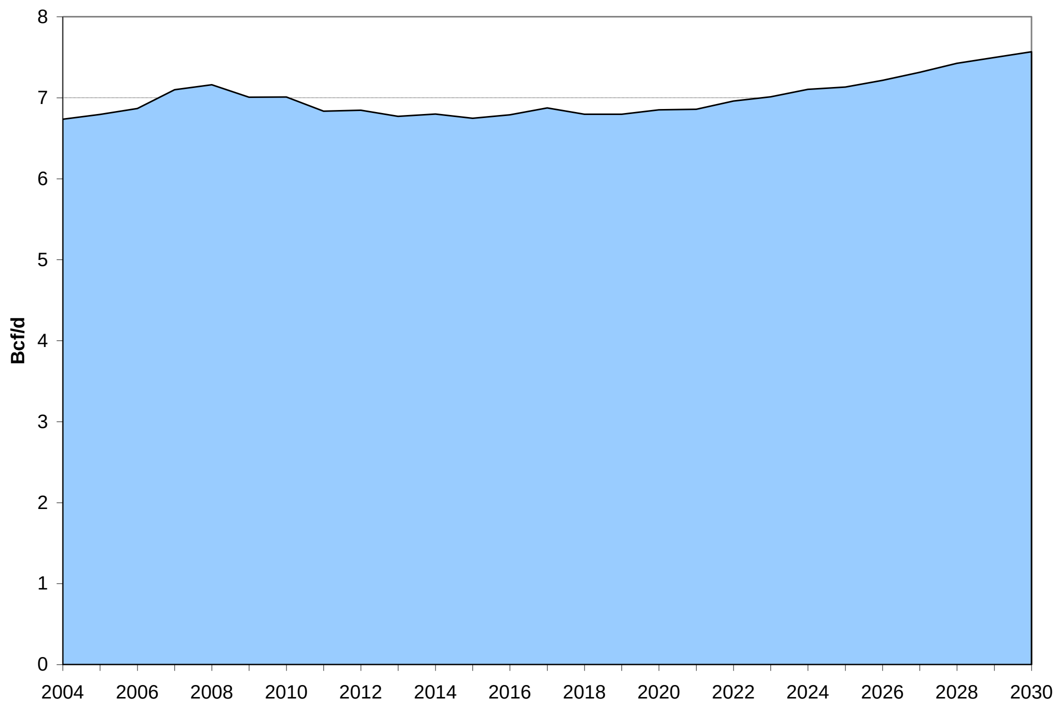


Source: EIA, AEO 2007

Midcontinent Region

Production for the Midcontinent region is projected to increase as seen in Figure B.3. Most of the growth in this region depends on the strength of non-conventional shale gas plays. The Fayetteville and the Woodford gas shale in the Arkoma basin have both been successful shale gas plays.

Figure B.3: Midcontinent Production

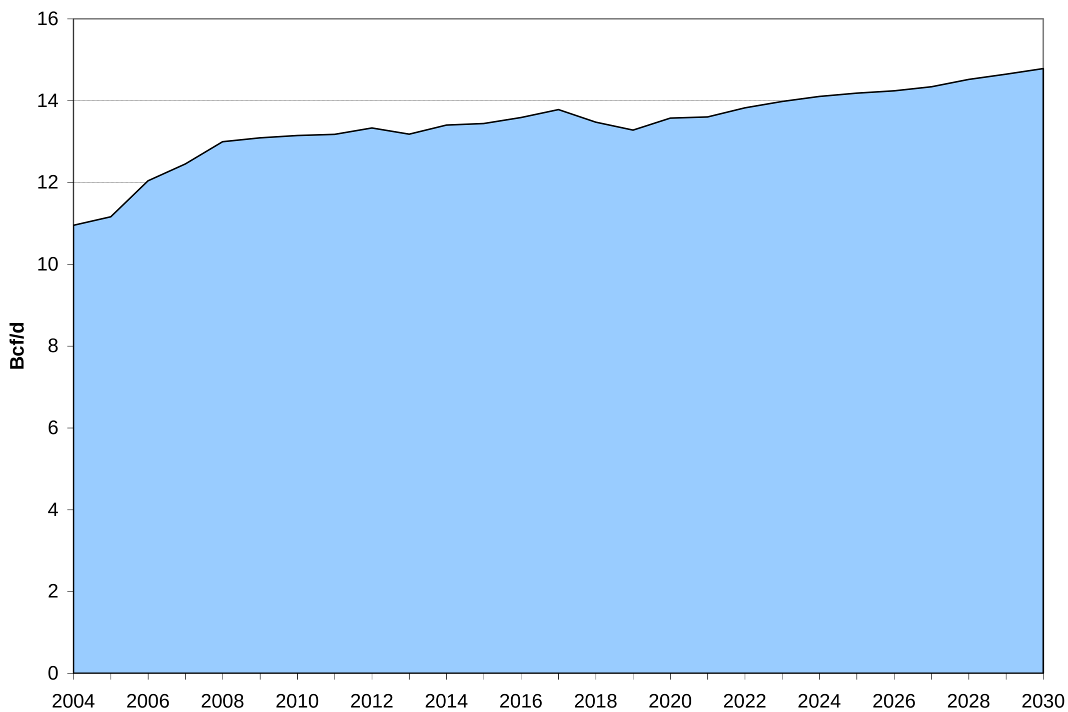


Source: EIA, AEO 2007

Rocky Mountain Region

Natural gas production in the Rockies region averaged 12.4 Bcf/day in 2006, an increase of 10% from 2004 as shown in Figure B.4. Technology advancements to extract gas from unconventional sources, such as coal bed methane and tight gas sands have contributed to the increased growth. Currently there are constraints in the Rockies region due to take away capacity; however, these positive growth trends are expected to continue in the near to midterm. When the proposed Rockies Express Pipeline ("REX") is placed in service, Rockies production is expected to grow and compete with the Gulf of Mexico production for a share of the Northeast market. Growth will predominately occur in the Jonah and Pinedale basins.

Figure B.4: Rocky Mountain Production

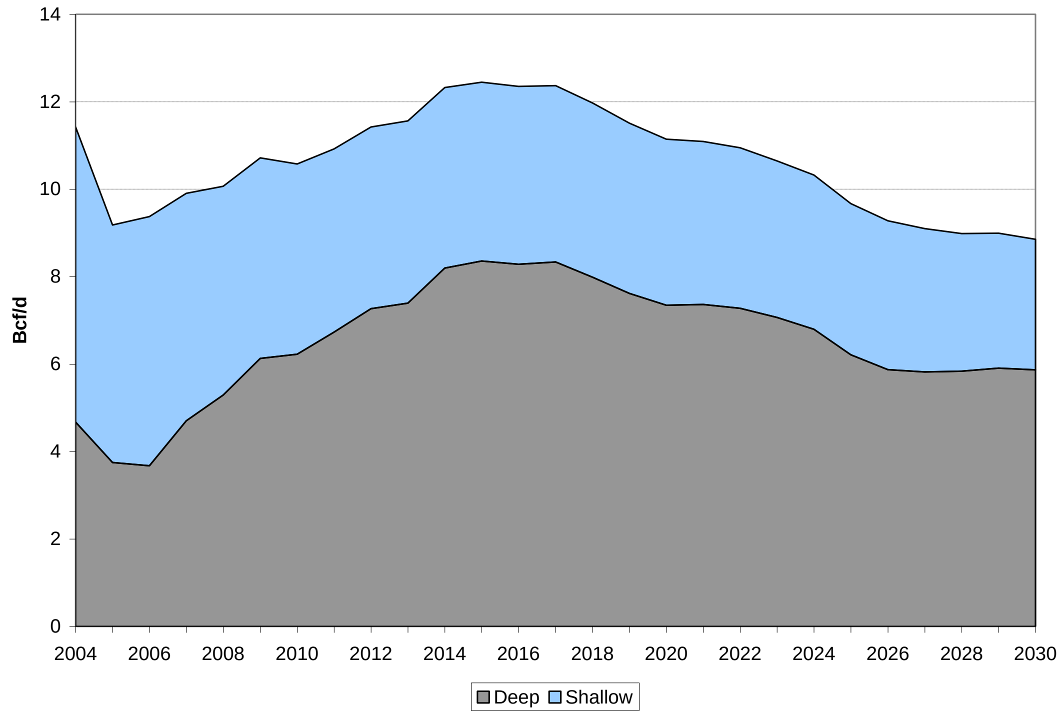


Source: EIA, AEO 2007

U.S. Offshore Gulf Region

A large volume of natural gas resources in this region remain in deep waters as shown in Figure B.5. Offshore deep water production is projected to peak in 2015 with 8.4 Bcf/day while offshore shallow water production is projected to decline steadily until 2030. This decline in production can be attributed to rising production costs. Total offshore production is expected to peak in 2015 at 12.5 Bcf/day. The offshore Gulf region along with Alaska and Atlantic Coast regions are estimated to contain more than one third of all undiscovered gas resources.

Figure B.5: Lower 48 Offshore Gulf Production



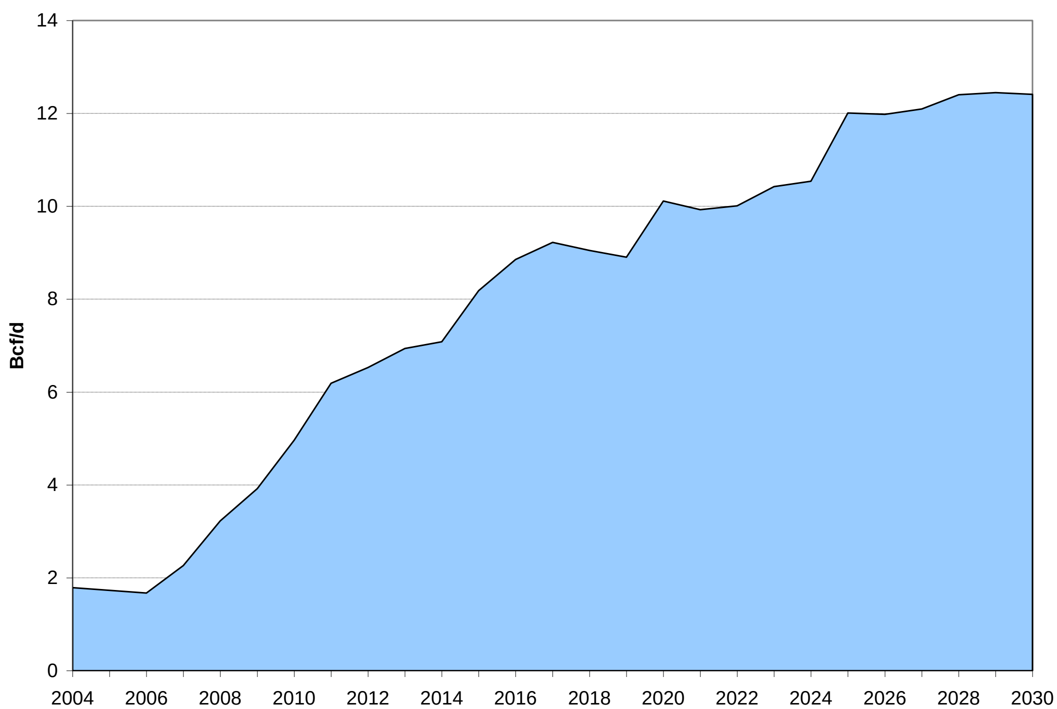
Source: EIA, AEO 2007

LNG Import Supply

Several LNG regasification terminal projects have been approved and are under construction in North America with many of these projects concentrated in the Gulf of Mexico region. Only a small number of the originally proposed LNG terminals are expected to become operational due to increased site restrictions and constraints on liquefaction capacity. Worldwide demand for natural gas is projected to increase especially in the growing economies in Asia and the U.S. is expected to participate in an increasingly competitive market for natural gas.

Figure B.6 shows that LNG imports are projected to increase significantly over the next twenty years as a means to bridge the gap between projected demand and domestic supplies.

Figure B.6: LNG Imports



Source: EIA, AEO 2007

With the exception primarily of the Rockies and other unconventional plays, the supply of natural gas in the U.S. is projected to decline with an overall expectation of a flat trend in the domestic supply of natural gas in the U.S. Increased reliance on LNG is projected as imports increase to keep up with growth in the demand for natural gas. Since the U.S. will be competing with countries that have very aggressive demand projections for natural gas, it is likely that the price of natural gas will continue to be sustained at the current high levels.

Appendix C

Forecasted Electric Generation and Emissions

Figure C.1: Forecast Electric Generation by Fuel Type – Reference Case

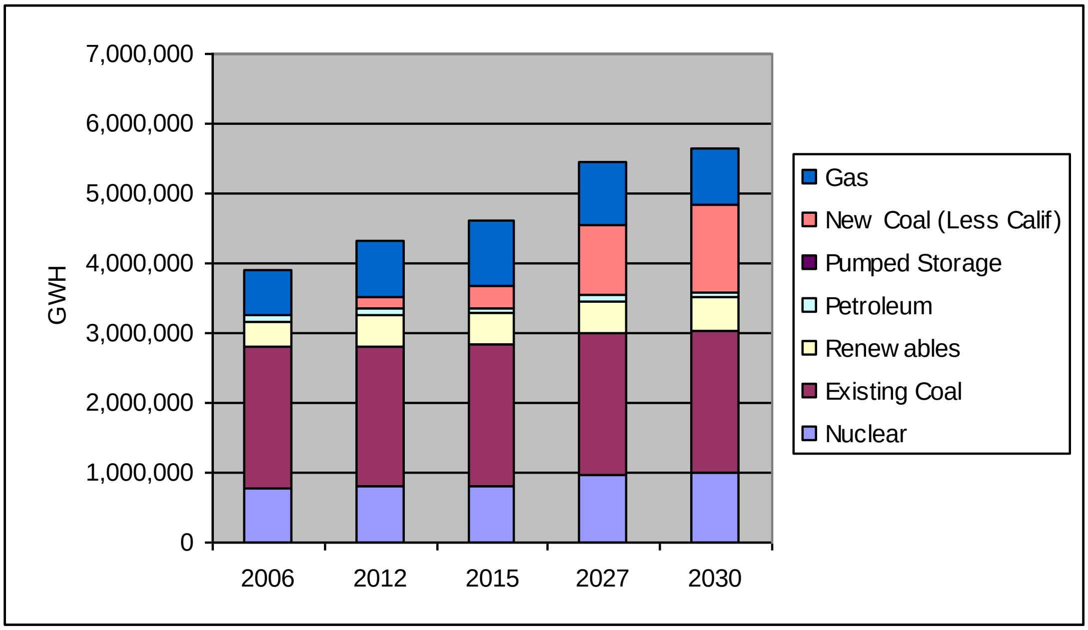


Figure C.2: Forecast CO_2 Emissions and Natural Gas Consumption for Electric Generation – Reference Case

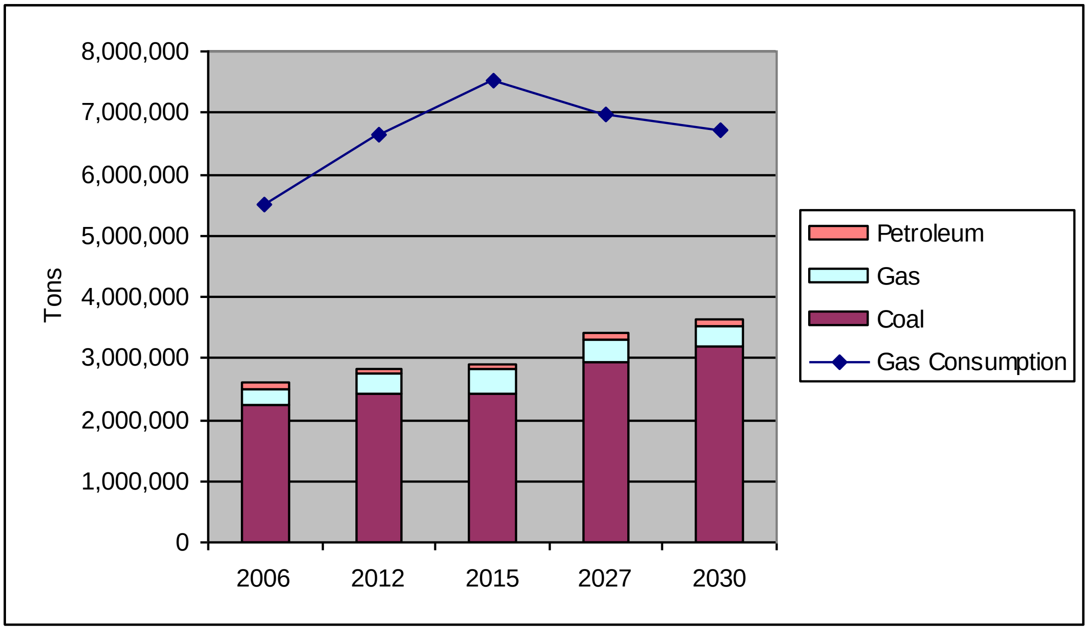


Figure C.3: Forecast Electric Generation by Fuel Type – Gas Supply Lower, High Technology, High CO_2 Control

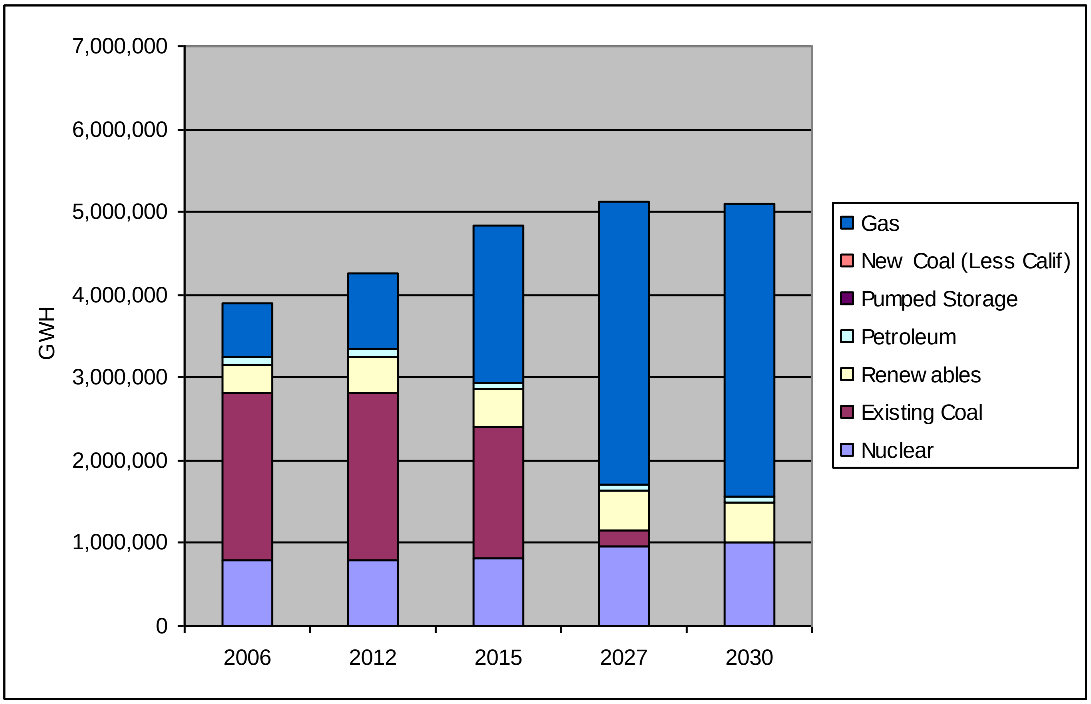


Figure C.4: Forecast CO_2 Emissions and Natural Gas Consumption for Electric Generation – Gas Supply Lower, High Technology, High CO_2 Control

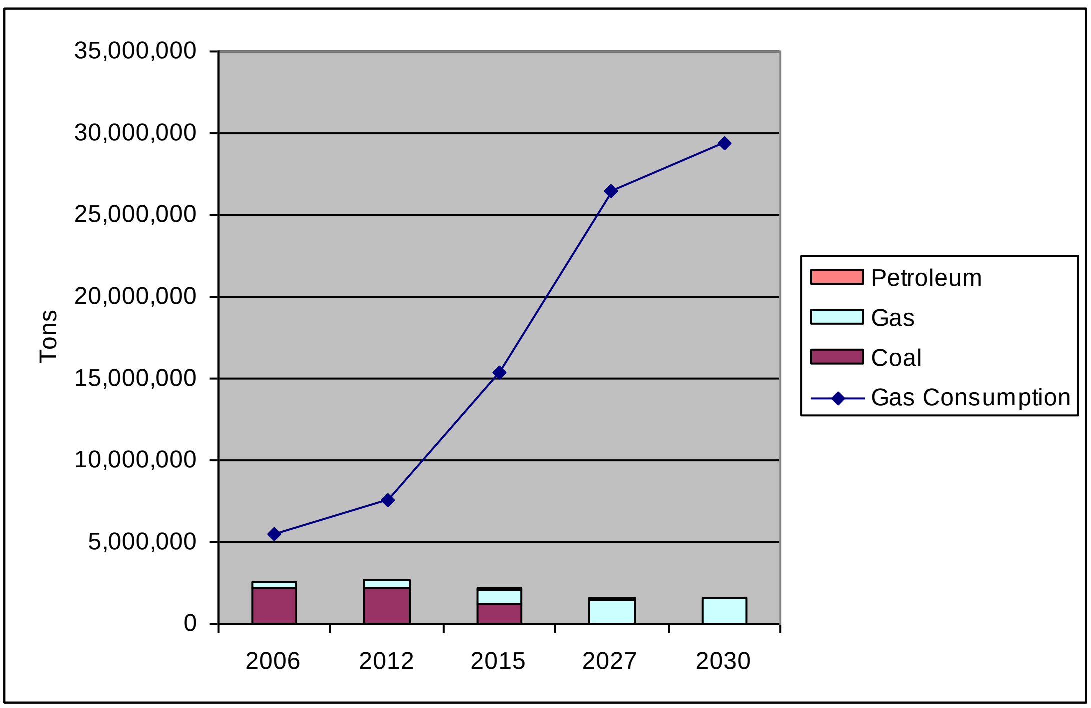


Figure C.5: Forecast Electric Generation by Fuel Type – Gas Supply Lower, 2006 Technology, High CO_2 Control

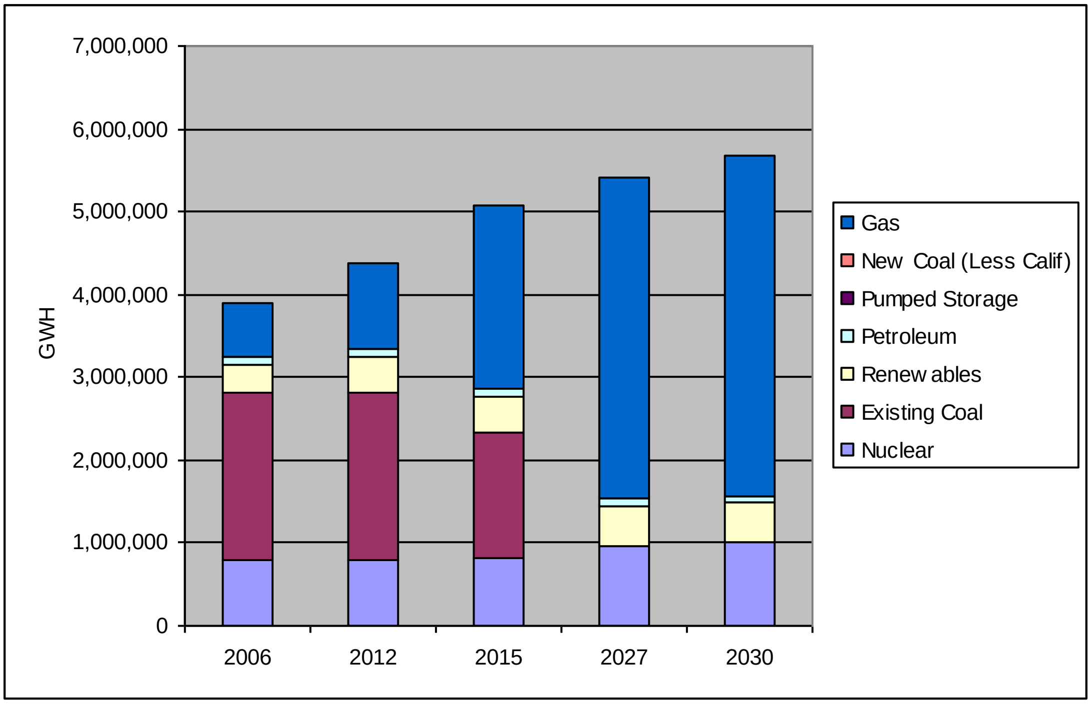


Figure C.6: Forecast CO_2 Emissions and Natural Gas Consumption for Electric Generation – Gas Supply Lower, 2006 Technology, High CO_2 Control

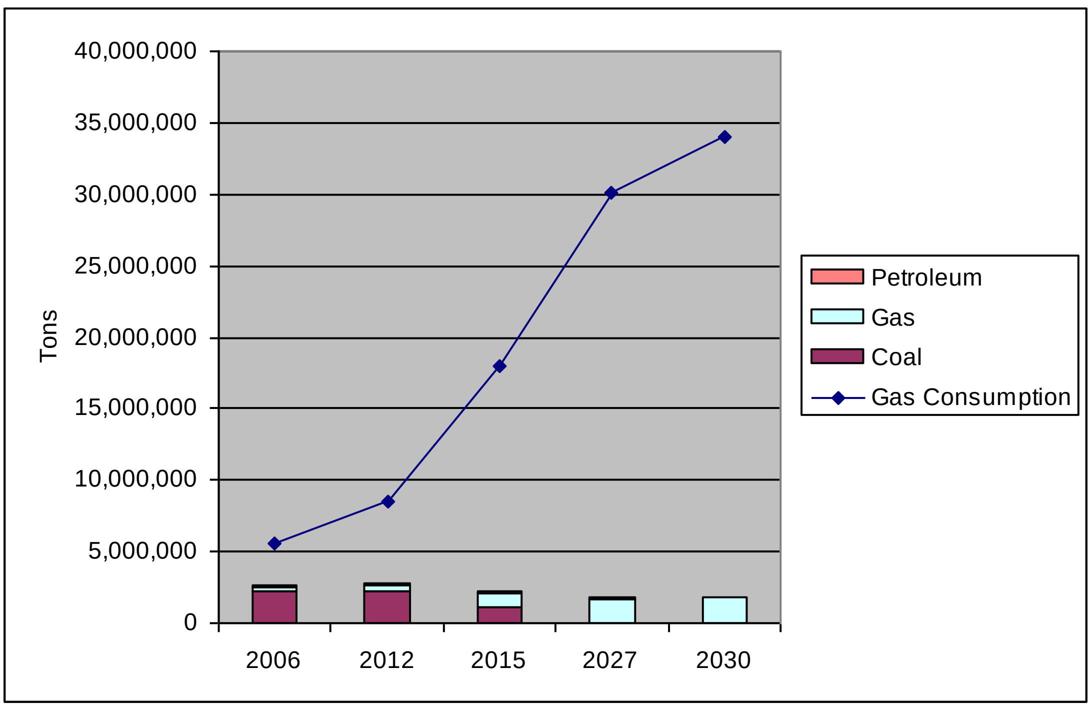


Figure C.7: Forecast Electric Generation by Fuel Type – Gas Supply Higher, High Technology, Low CO_2 Control

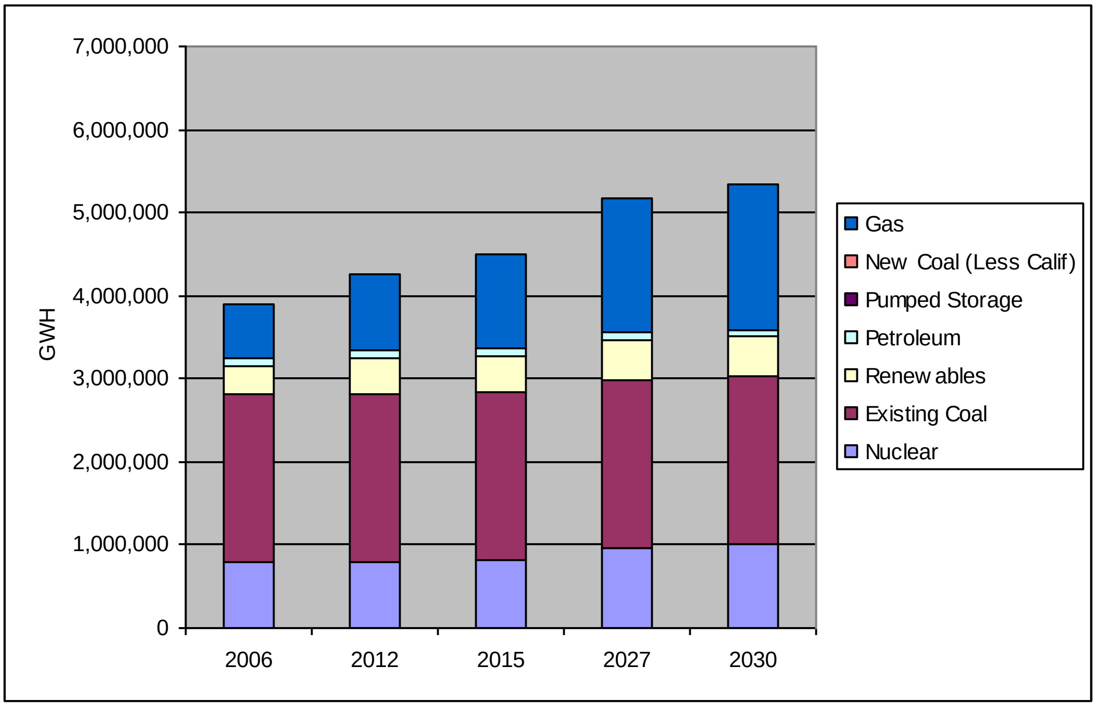


Figure C.8: Forecast CO_2 Emissions and Natural Gas Consumption for Electric Generation – Gas Supply Higher, High Technology, Low CO_2 Control

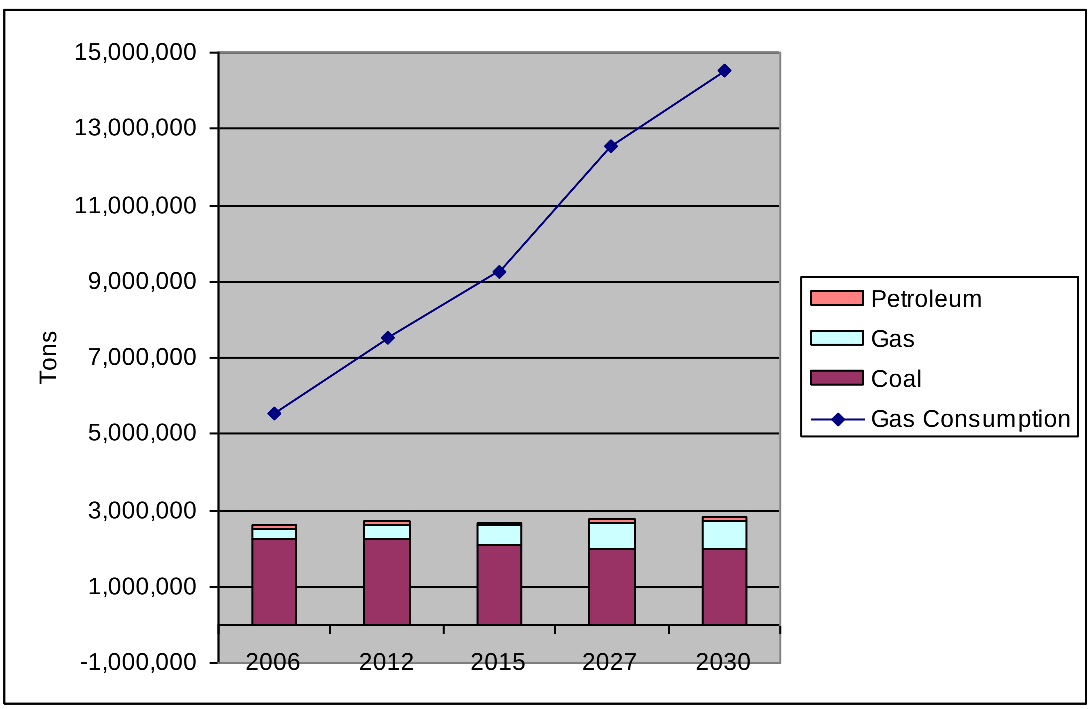


Figure C.9: Forecast Electric Generation by Fuel Type – Gas Supply Higher, 2006 Technology, Low CO_2 Control

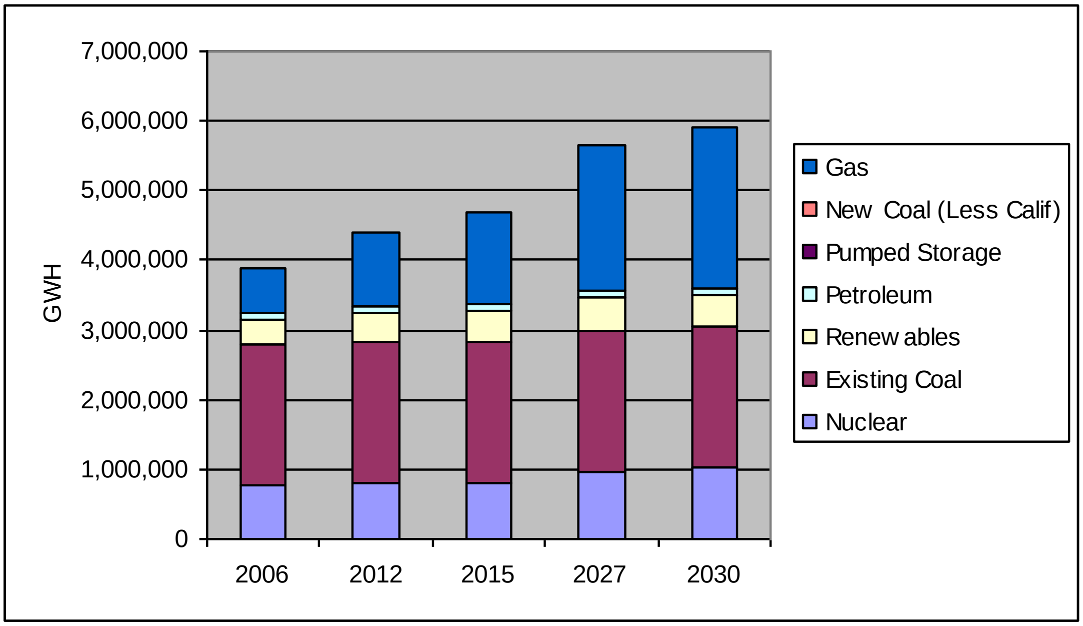
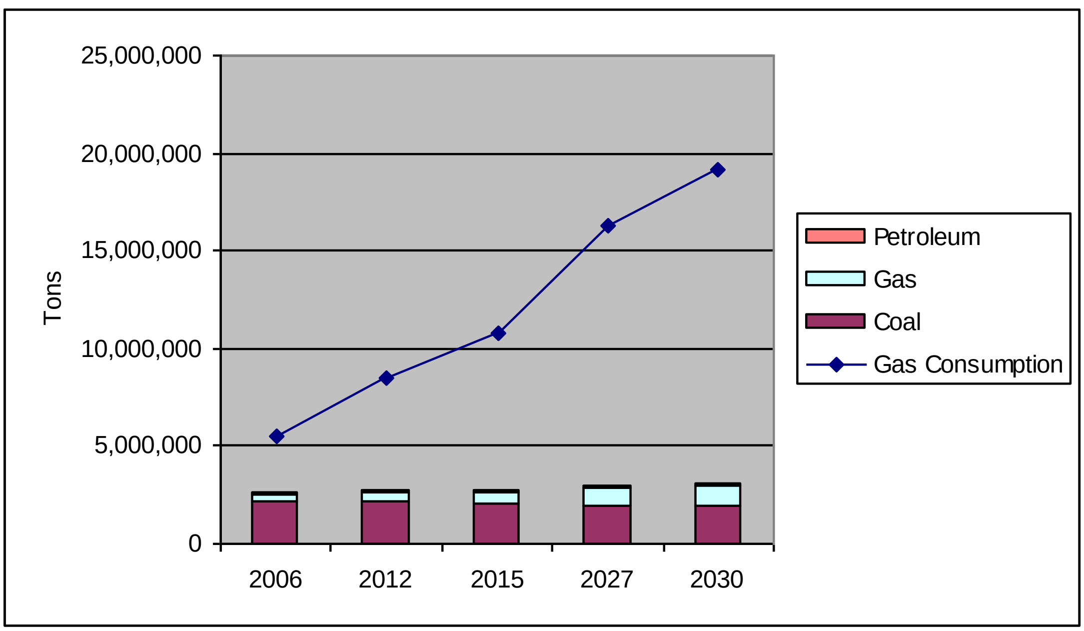
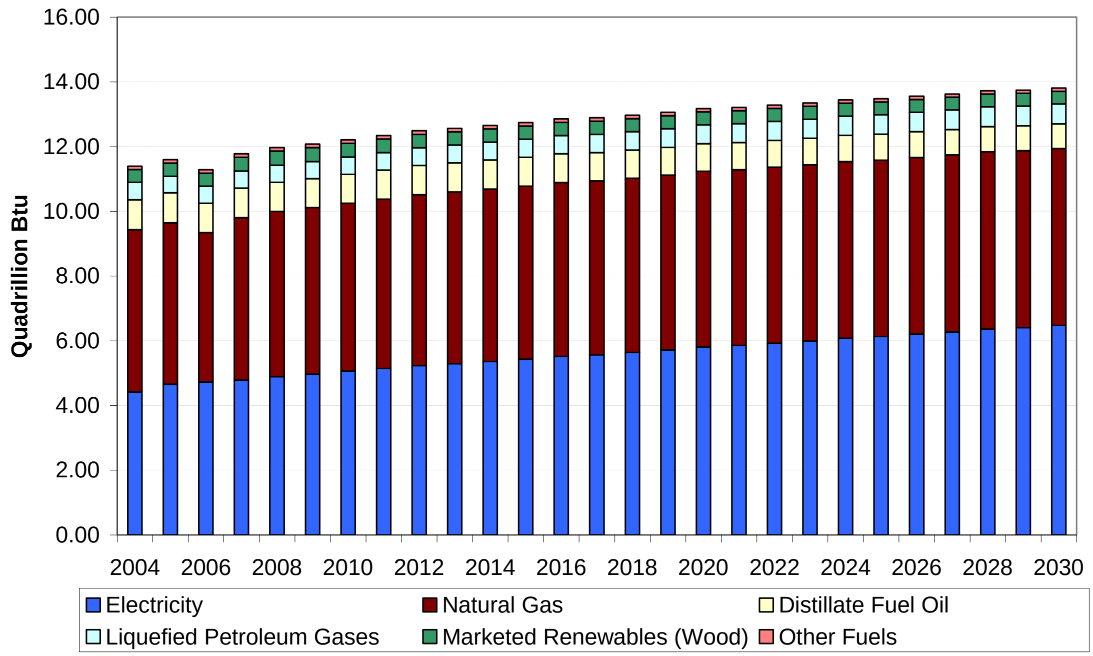


Figure C.10: Forecast CO_2 Emissions and Natural Gas Consumption for Electric Generation – Gas Supply Higher, 2006 Technology, Low CO_2 Control



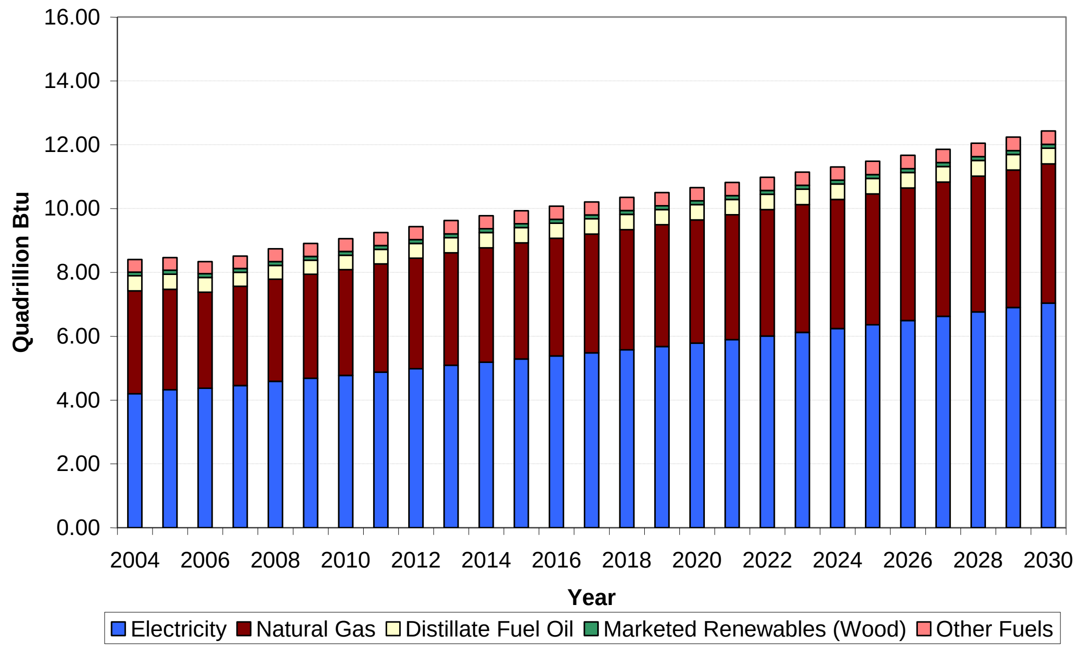
Appendix D
Forecasted R&C Natural Gas and Electric Consumption

Figure D.1: Total Residential Consumption by Fuel Type



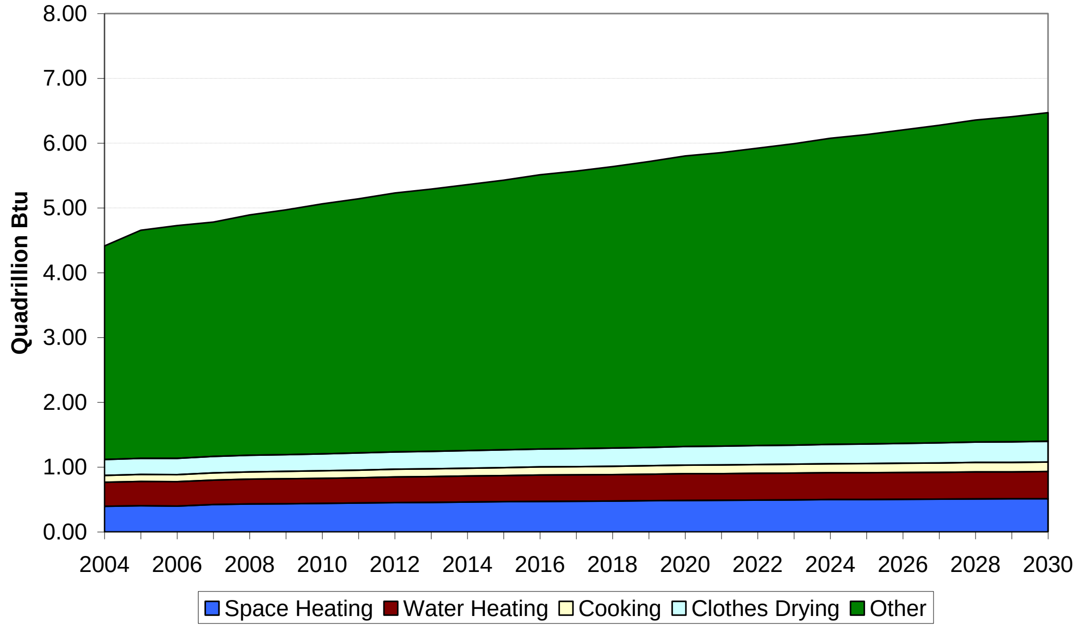
Source: EIA, AEO 2007

Figure D.2: Total Commercial Consumption by Fuel Type



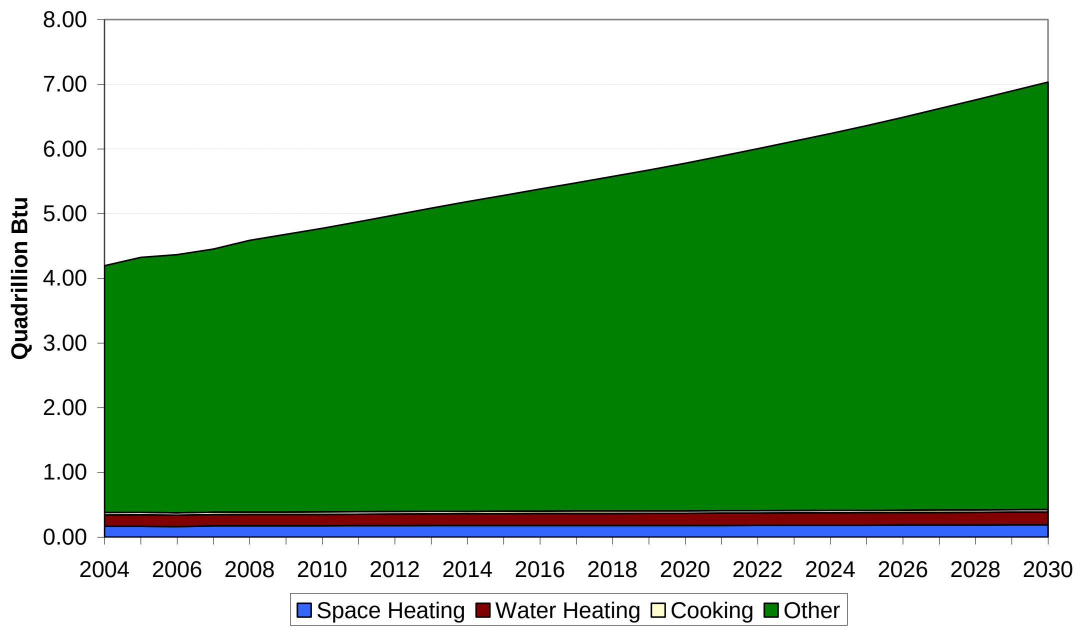
Source: EIA, AEO 2007

Figure D.3: Residential Consumption of Electricity by Application



Source: EIA, AEO 2007

Figure D.4: Commercial Consumption of Electricity by Application



Source: EIA, AEO 2007