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Abstract

This report presents the California Energy Commission staff's final assessment of California's natural gas market. It covers natural gas demand, supply, infrastructure, price, and possible alternative outcomes based on differing assumptions. The report is based upon the staff's preliminary and revised assessments issued in June and August 2007, the comments received at the June, July, and August 2007 public workshops held on these reports and the related Scenarios Project, and additional updated information.

California natural gas demand growth for the electricity generation sector is growing at 2.4 percent, but when combined with natural gas growth in the other sectors, overall annual natural gas growth is 1.3 percent over the next decade. U.S. natural gas growth over the same period is 2.1 percent.

U.S. marketable natural gas production remains relatively flat in the future, rising in some years and dropping in others. Staff projects that liquefied natural gas (LNG) imports into North America increase up to 14 billion cubic feet per day by 2017. Regasified LNG imports from Mexico into San Diego begin in 2008. This LNG displaces domestic production from the Southwest.

During the 2007-2017 forecast periods, all major pipeline systems serving California, except the Kern River pipeline, operate at usage rates between 60 and 70 percent. The interstate North Baja pipeline reverses and expands to allow the flow of regasified LNG from the Costa Azul LNG terminal in Baja California. The intrastate pipeline Line 300 expands to accommodate the increased demand for natural gas in the Pacific Gas and Electric system.

Under the current assessment, prices may fall early in the forecast period and then rise to slightly above $7 per thousand cubic feet in real 2006 dollars by 2017. More supply options during the period could increase natural gas-on-gas competition. Basis spreads between Henry Hub (Louisiana) and other hubs increase during the forecast period because the majority of LNG imports come into the Gulf Coast, close to Henry Hub. California natural gas prices could be higher than Henry Hub prices.

Forecasts require that choices be made about assumptions and inputs for demand, supply, infrastructure, and prices during the forecast period. These assumptions and inputs about the future, however, are inherently uncertain and may not materialize, thereby changing the outcomes described in this report. To address these possibilities, alternative assumptions and outcomes that could reasonably occur are evaluated.

Keywords: natural gas, liquefied natural gas LNG, supply, demand, infrastructure, price, production, pipelines, regasification.

EXECUTIVE SUMMARY

Introduction

California Energy Commission staff used the World Gas Trade Model/North American Regional Gas model to forecast natural gas prices for the *Revised Natural Gas Market Assessment*; but in a departure from previous years, the model results are presented as a “reference case” that recognizes that modeling results do not properly address the uncertainty of key variables. A preliminary reference case was published May 2007 and was the subject of a June 7 workshop at the Energy Commission. A revised reference case was published in August 2007 and reflected comments received at this and other workshops. In addition, two supplemental sensitivity cases were run: one assuming a liquefied natural gas (LNG) terminal in Southern California, and one assuming dry hydro conditions. This final reference case includes minor modifications to the revised reference case. For all cases, staff presents its estimates of natural gas demand, supply, price, and infrastructure effects. The reference case is supplemented by a qualitative discussion of alternative assumptions and outcomes. The results of the alternative scenarios are also presented.

A report on the development of worldwide LNG trade under different scenarios was developed with the preliminary reference case. The findings of that study, *The Outlook for Trade in Liquefied Natural Gas Projections to the Year 2020,*[1] and public comments received are reflected in this document.

Major findings of the report are presented below. These findings do not differ from those presented in the previous version of the report.

Natural gas prices are approximately $0.50 to $1.00 per MMBtu higher than the initial reference case originally presented June 7, 2007. The model still economically sequences LNG over domestic resources and pipeline imports, and staff’s constraint of LNG imports require higher production of domestic resources to balance the North American natural gas market. Increasing domestic production requires higher natural gas prices. Limiting LNG deliveries changes North American natural gas flows such that the basis differentials to California do not swing from negative to positive as radically as in the June 7 case. Therefore, California continues to experience natural gas border prices that are slightly lower than the Henry Hub price forecast.

Demand

- North American natural gas demand is projected to increase at an annual rate of 2.3 percent over the next decade. The demand is expected to expand from 71,657 million cubic feet (MMcf) per day in 2007 to 89,720 MMcf per day in 2017.

[1] CEC-200-2007-017, August 2007

- The anticipated North American demand growth rates of the United States, Canada, and Mexico are forecast to be 2.1 percent, 2.5 percent, and 4.6 percent, respectively.
- North America's gas demand is dominated by the United States. Over the next decade, the United States will account for 82 percent of the gas consumed, followed by Canada at 13 percent and Mexico at 5 percent.
- In the North American natural gas market, gas demand from the United States' electric power sector is the fastest growing sector. The power generation sector is expected to increase at an annual rate of 5.6 percent. The total increase for other end-use sectors is basically flat.
- California's natural gas demand is forecast to increase at a much slower rate than either the North American or the U. S. natural gas market. California's natural gas demand for the electric power sector is expected to increase by 2.4 percent over the next decade, while overall gas demand in all sectors is forecast to increase slightly higher than 1 percent annually. Some contributing factors to this slower growth in overall demand are:
    - Increased use of renewable energy.
    - Slower growth rate in electric generating capacity.
    - More fuel-efficient natural gas power plants.
    - Flat growth in the industrial sector.
    - Improved efficiency requirements for buildings and appliances through standards.
    - New demand-side management programs.

Supply

- North America's marketable natural gas production is projected to increase slightly during the forecast period. The slightly rising production trend from the preliminary version of the report is due to a reduction in the amount of LNG imported into North America. Staff restricted the flow to 14 billion cubic feet (Bcf) per day in 2017, down from the previous economically derived flow of 24 Bcf per day. Removing 10 Bcf per day of LNG imports consequently raises prices to increase additional domestic exploration by enough to meet all demand.
- Natural gas from Arctic Canada and from Alaska's North Slope is assumed to be unavailable during the forecast period of 2007-2017.
- U.S. marketable natural gas production is estimated to increase slightly in the future, rising in some years and dropping in others. The change from the previously declining production trend in the June forecast results from the decrease in amount of LNG imports and increase in Canadian oil sands use of natural gas between the preliminary report and this revised version.

- The forecast estimates that North America's natural gas supplies would be augmented by LNG imports, increasing by 266 percent, from 3,945 MMcf per day in 2007 to 14,442 MMcf per day in 2017.
- The amount of gas produced in the Southwest, entering California at Blythe, gradually decreases during the forecast period as natural gas imported from Mexico (Costa Azul Facility) displaces domestic production from the Southwest.
- Importation of LNG is expected from Mexico into San Diego through the Transportadora De Gas Natural De Baja California (TGN) pipeline beginning in 2008. Gas imported from Costa Azul via the TGN to San Diego and the Baja Norte to Ehrenberg is projected to grow from zero to more than 400 MMcf per day by 2017.
- The Energy Information Administration (EIA) has revised downward its North American natural gas production estimates for 2002-2007.
- U.S. production has been relatively flat for the last several years, even though natural gas prices and the number of natural gas wells drilled annually have both increased.

Infrastructure

- During the forecast period, all major pipeline systems serving California, except the Kern River pipeline, operate at average annual usage rates between 60 and 70 percent. However, during the winter months they operate at higher rates.
- Kern River's capacity usage first hovers around 80 percent, then exceeds 90 percent in the middle and end of the forecast horizon.
- LNG entering California could displace natural gas from the Southwest. As a result, flows along the El Paso South system lose market share to LNG supplies from Baja, Mexico.
- Two pipelines affecting California, one interstate and one intrastate, could expand. The interstate pipeline, North Baja westbound, now delivers conventional natural gas to its end users in Baja Mexico. However, after Costa Azul begins operation, this pipeline will reverse and deliver regasified LNG at Blythe/Ehrenberg. As a result, North Baja will expand to accommodate the flow of regasified LNG. The intrastate pipeline, Line 300, receives natural gas from the Southwest and the Rocky Mountains, delivering into the Pacific Gas and Electric (PG&E) utility system. The economics of additional LNG becoming available at the California border result in the model expanding PG&E Line 300. This expansion accommodates the increased natural gas demand in the PG&E system.

Price

- The model projects relatively stable prices early in the forecast period of 2007 to 2017, rising thereafter to approximately to $7 per thousand cubic feet (Mcf) by 2017.
- More available supply options could increase gas-on-gas competition over the next 10 years.
- Basis spreads between Henry Hub (Louisiana) and other hubs increase during the forecast period. This implies that the Henry Hub price is not rising in lockstep with other North American hubs and remains low because the majority of expected imported LNG coming into the Gulf Coast is close to Henry Hub.
- Some of the basis spreads that traditionally were negative become positive. The discount that California has enjoyed relative to Henry Hub becomes a premium.

Alternative Cases

- Two approaches were used to acknowledge the uncertainty of forecasting natural gas demand when developing low and high case demand assumptions — one quantitative and one qualitative.
- The quantitative approach uses the distribution of recorded demand growth to create a range around the expected demand case. This analysis demonstrates that a reasonable high case could be 1.5 to 2.0 trillion cubic feet (Tcf) higher than staff's reference case. A reasonable low case could be 1.5 to 2.0 Tcf lower than staff's case.
- The qualitative approach identifies specific factors that each can contribute to higher versus lower demand.
- A heuristic tool was developed to create a snapshot of natural gas supply that can be used to assess supply/demand balance.
- The high supply case assumes that production per well remains constant. It illustrates the number of wells that must be drilled such that no "gap" is required to be met with LNG.
- The low supply case assumes that production per well declines and that the number of wells drilled is capped at the 2006 number of approximately 30,000 wells. It also assumes that Canadian supply falls off somewhat more quickly. In this case, the imbalance grows to nearly 10 Tcf by 2017.
- There is a relationship between oil and natural gas prices, but it is difficult to characterize and it is not constant.

CHAPTER 1: INTRODUCTION

Background

The outcome of staff's natural gas modeling, conducted for the *2005 Integrated Energy Policy Report* (*2005 IEPR*), was a single point forecast that incorporated the following expected trends in supply, demand, infrastructure, and price:

- Natural gas production from the "lower 48" states was expected to increase by 1.6 percent per year.
- Proposed LNG facilities on the East and West Coasts delivered natural gas to California.
- Imports from other states and from Canada largely met steadily increasing demand growth.
- Increasing natural gas prices reflected the ongoing combined effects of the energy crisis of 2001 and the devastating hurricanes of 2005.
- High prices from the above events were expected to be temporary.
- Short-term natural gas prices were expected to be volatile.

The equilibrium models used deterministically by the California Energy Commission (Energy Commission) and others cannot adequately capture all events — foreseen and unforeseen — that could ultimately affect California's natural gas situation. For example, the effect of both high or low temperature and variations in either rainfall or the annual snowpack could well increase the demand for additional natural gas-fired generation. Greenhouse gas (GHG) emission reduction policies could also affect whether either coal or natural gas is used to meet U.S. electricity demand. Future liquefied natural gas (LNG) supply could be affected by construction and expansion of LNG terminals, geopolitical issues, and supply diversions. Such uncertainties led to the *2005 IEPR* recommendation that staff further investigate alternative forecasting methods in the *2007 IEPR* cycle to better assess natural gas prices.

Approach for the 2007 Assessment

The approach for staff's 2007 *Natural Gas Market Assessment (2007 Assessment)* is very different from that of previous assessments. The increase in liquefied natural gas (LNG) has created a world gas market. This required staff to supplement its use of the North American Regional Gas (NARG) with a World Gas Trade Model (WGTM), Appendix F provides a brief description of the model. The energy commission staff has used the NARG model since 1989. NARG is a regional model contained within the WGTM. Energy Commission staff has used the North American Regional Gas (NARG) model to forecast the natural gas market. This natural gas market outlook includes forecasts of natural gas supply, consumption, infrastructure changes and prices. Though staff continues to use NARG for the *2007 Assessment*, it is explicitly offered as a "reference case" in recognition that modeling results do not properly address the uncertainty of key variables. Staff did not have the sufficient time to perform the appropriate stochastic analysis. Therefore, staff supplemented the reference case with a qualitative discussion of alternative assumptions and outcomes that could reasonably occur around the reference case.

This report discusses the Energy Commission staff's final assessment of California's natural gas demand, supply, infrastructure, and prices for the forecast period 2007-2017. This final assessment reflects public comments from the June 7, and August 16, 2007 workshops on the preliminary and revised natural gas assessment reports, and the July 9, 2007, workshop on the scenario assessment of California's electricity system. The scenario analysis evaluates alternative resource plans predicated upon large penetrations of preferred resources to gain insight into how selected performance measures — reliability, cost, and environmental impacts (such as GHG emissions and water use) — could change across resource cases. Different assumptions result in a range of natural gas prices.

This natural gas assessment report is one of several Energy Commission efforts relating to natural gas. Ongoing work by the Energy Commission's Public Interest Energy Research (PIER) Program is evaluating the role and opportunities for natural gas storage. The results of this PIER work will be incorporated into future natural gas assessments prepared by staff.

Global developments limiting access to LNG supplies could affect the ability of LNG to meet the projected gap between natural gas supply and demand. For this reason, the Energy Commission requested that LNG expert James Jensen prepared a report on the development of worldwide LNG trade under differing scenarios. His results are incorporated in this revised natural gas assessment and provided in full in a separately published report, *The Outlook for Trade in Liquefied Natural Gas Projections to the Year 2020*.[2]

The preliminary reference case that formed the basis of the June 2007 draft staff report contained many assumptions about future conditions that affect natural gas. The final reference case includes the following revisions to assumptions:

- North American LNG regasification capacity was limited to 14 billion cubic feet (Bcf) per day, a lowering of 10 Bcf per day from the preliminary reference case to reflect existing regasification projects and those projects under construction now or for which expansions have been approved.
- Pipeline flows from Baja into San Diego (Otay Mesa) were restricted to match the current physical capability of the San Diego Gas & Electric (SDG&E) system to accept natural gas from the Baja LNG terminal.

[2] CEC-200-2007-017, August 2007

- Continued expansion in the Alberta oil sands to extract petroleum from these sands has resulted in increasing natural gas consumption for this sector.
- The quantity of natural gas produced within California was reduced to better reflect current production capability.
- Power generation demand projections for the Western Electricity Coordinating Council (WECC) were updated with numbers provided by the Energy Commission's Electricity Analysis Office.
- Residential, commercial, and industrial demand projections were updated with numbers provided by the Energy Commission's Demand Analysis Office.

In addition, staff has prepared four sensitivity cases to test alternatives relative to the reference case. The cases are as follows:

- A simulation of dry hydro conditions.
- A 1 Bcf per day LNG terminal in Southern California, operational in 2011.
- A 1 Bcf per day LNG terminal in Southern California, operational in 2011 and expanding in 2015 to 2 Bcf per day.
- A 1 Bcf per day LNG terminal in Southern California, operational in 2011, and a 1 Bcf per day LNG terminal in the Pacific Northwest, operational in 2015.

Staff divided the discussion of the natural gas market into the following chapters:

- **Chapter 2: Natural Gas Demand** on projected end-use consumption.
- **Chapter 3: Natural Gas Supply** on domestic production and the importation of LNG.
- **Chapter 4: Natural Gas Infrastructure** on the pipeline network that links supply to demand.
- **Chapter 5: Natural Gas Prices** on prices changes and basis differentials.
- **Chapter 6: Alternatives Cases** on alternative natural gas market outlooks.

Technical data in support of these chapters are presented in Appendices.

CHAPTER 2: NATURAL GAS DEMAND

Introduction

This chapter discusses North American demand for natural gas, changing trends in the natural gas market, and the implications that demand for natural gas throughout North America will have on the California market. The chapter also covers the California Energy Commission staff's outlook for natural gas demand over the forecast period of 2007 to 2017. The outlook contains projections of natural gas consumption by end use for North America, the Western states and California over the next decade. The major end use sectors analyzed in the forecast are residential, commercial, industrial, and power generation.

Information on the North American natural gas market is included to establish a baseline for analysis and evaluation of the natural gas market. The assessment of California's natural gas demand in the current outlook includes the effect of the state's natural gas policies for energy efficiency standards (buildings and appliance standards and utility programs) and renewables programs that will be implemented over the forecast horizon.

Major Findings

- North American natural gas demand is projected to increase at an annual rate of 2.3 percent over the next decade. The demand is expected to expand from 71,657 MMcf per day in 2007 to 89,720 MMcf per day in 2017.
- The anticipated North American growth rates of the United States, Canada, and Mexico are forecast to be 2.1 percent, 2.5 percent, and 4.6 percent, respectively.
- North America's natural gas demand is dominated by the United States. Over the next decade, the United States accounts for 82 percent of the natural gas consumed, followed by Canada at 13 percent and Mexico at 5 percent.
- In the North American natural gas market, natural gas demand from the United States' electric power sector is the fastest growing sector. The power generation sector is expected to increase at an annual rate of 5.6 percent. The total increase for other end-use sectors is basically flat.
- California's natural gas demand is forecast to increase at a much slower rate than either the North American or the U. S. natural gas market. California's natural gas demand for the electric power sector is expected to increase by 2.4 percent over the next decade, while overall natural gas demand in all sectors is projected to increase 1.3 percent annually. Some contributing factors to this slower growth in overall demand are:

- Increased use of renewable energy
- Slower growth rate in electric generating capacity
- More fuel-efficient natural gas power plants
- Flat growth in the industrial sector
- Improved efficiency requirements for buildings and appliances standards
- Demand-side management programs

North American Natural Gas Demand

The evaluation of the North American natural gas market includes the United States (lower 48 states), Canada, and Mexico. The North American natural gas market consumed approximately 74 billion cubic feet (Bcf) of natural gas in 2006. This amount represents roughly 26 percent of the world natural gas consumption. The United States is the major consumer of natural gas in the North American market, accounting for 82 percent of the natural gas consumed, followed by Canada at 13 percent and Mexico at 5 percent.

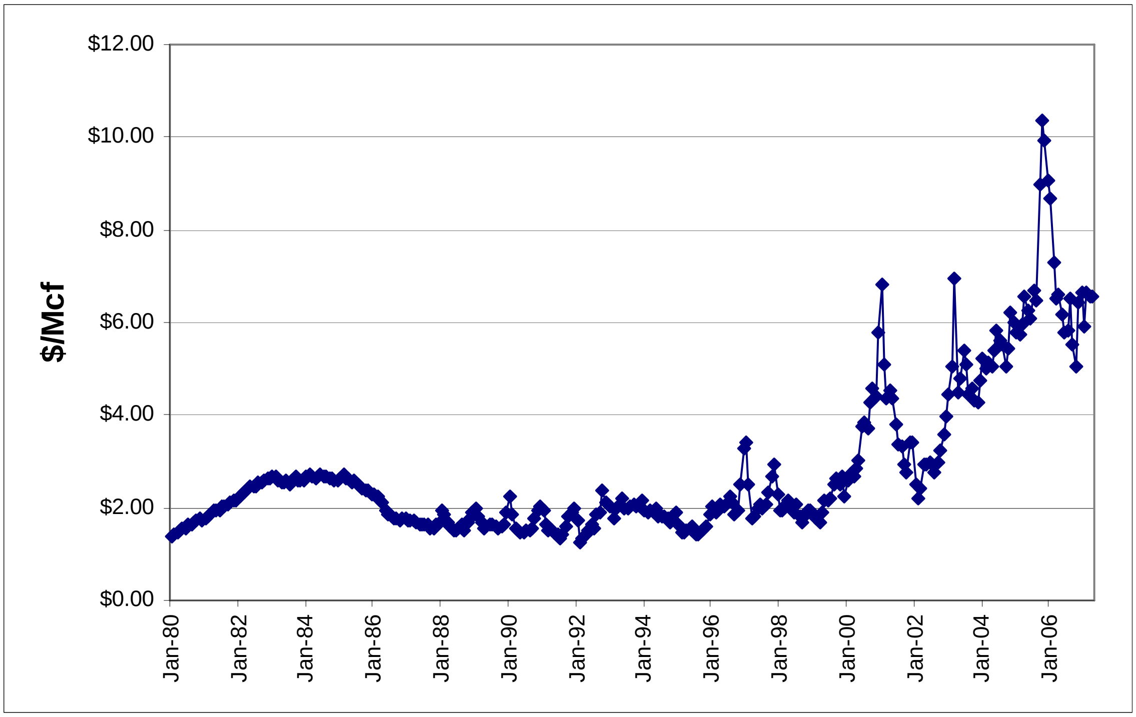
The primary factors influencing the consumption of natural gas are:

- Natural gas price
- Economic growth
  - Gross domestic product
  - Industrial production
- Weather
  - Heating degree days
- Population
- Price of petroleum
- Energy policies
  - Renewable energy mandate
  - Energy efficiency standards for buildings and appliances
  - Demand-side management programs

United States

Natural gas prices were fairly stable during the 1990s but have increased significantly and become more volatile since 2000 (see **Figure 1**). In 2006 dollars, the wellhead price in the United States increased at an annual rate of 2 percent in the 1990s and 12.4 percent annual rate since 2000.

Figure 1: U. S. Natural Gas Wellhead Price in 2006 Dollars



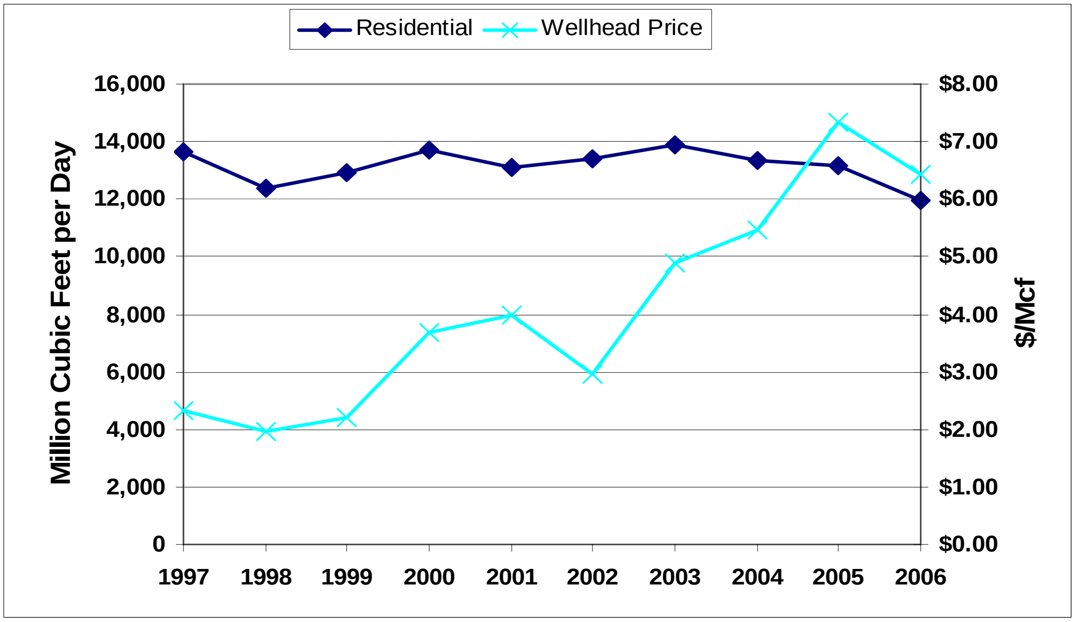
Source: Energy Information Administration

The impact of rising natural gas prices on consumption varies across end-use sectors. The consumption of natural gas in the residential and commercial end-use sectors does not appear to be price sensitive. As shown in **Figures 2 and 3**, residential and commercial end-use consumption have remained fairly constant, albeit with a small decline, over the past decade even though natural gas prices and use of natural gas appliances have increased significantly in the state since 2000. This would normally cause an increase in gas demand which has not occurred. The flat to slight decline in natural gas consumption in the residential sector can probably be attributed more to increased efficiency of natural gas appliances and the response of the residential sector to demand-reduction programs.

This apparent lack of demand response to increasing natural gas prices has been attributed to the following hypotheses: (1) household expenditure for energy is not a significant portion of disposable income; (2) population growth has resulted in an overall increase in natural gas use; (3) increasing economic activity keeps demand high; and (4) the inability of the sectors to switch to alternate fuel sources.

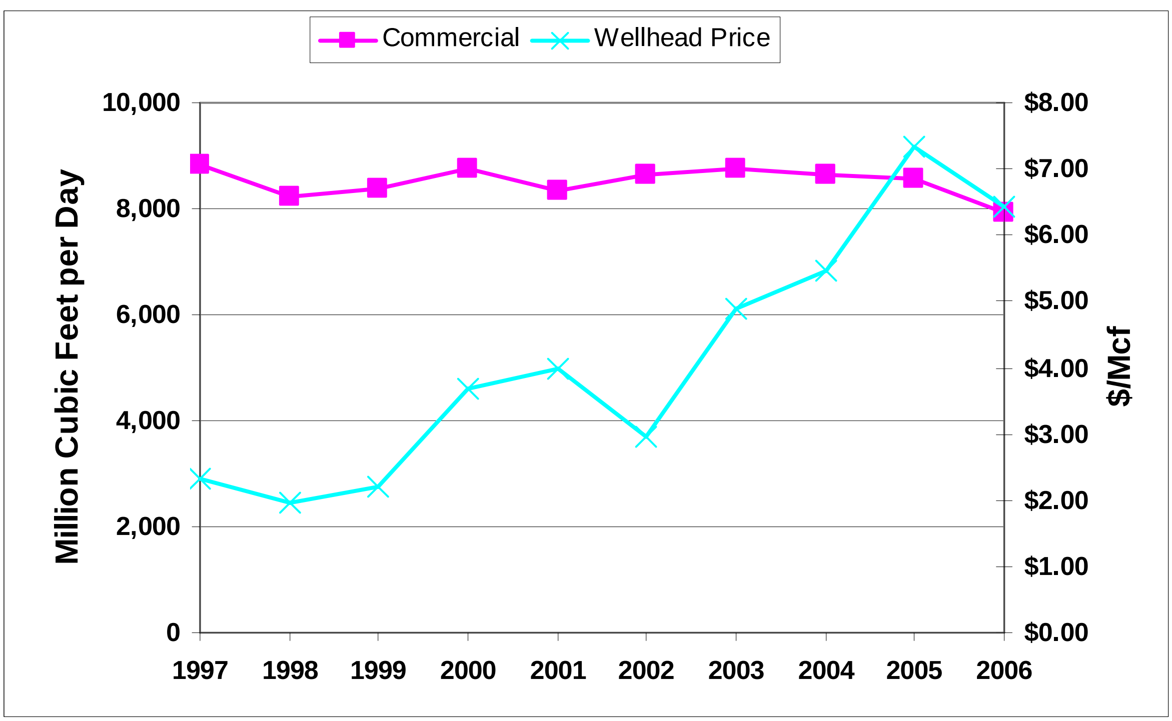
Natural gas price increases have had the greatest impact on consumption in the industrial sector. Over the past decade, the industrial sector natural gas consumption declined at an annual average rate of 2.7 percent (see **Figure 4**). The impact of higher natural gas prices has been most evident in the energy-intensive industries. Many of these industries have relocated to regions of the world where natural gas prices are below domestic prices or have lost out to competitors that have access to cheaper natural gas supplies.

Figure 2: U. S. Residential Consumption vs. Natural Gas Price in 2006 Dollars



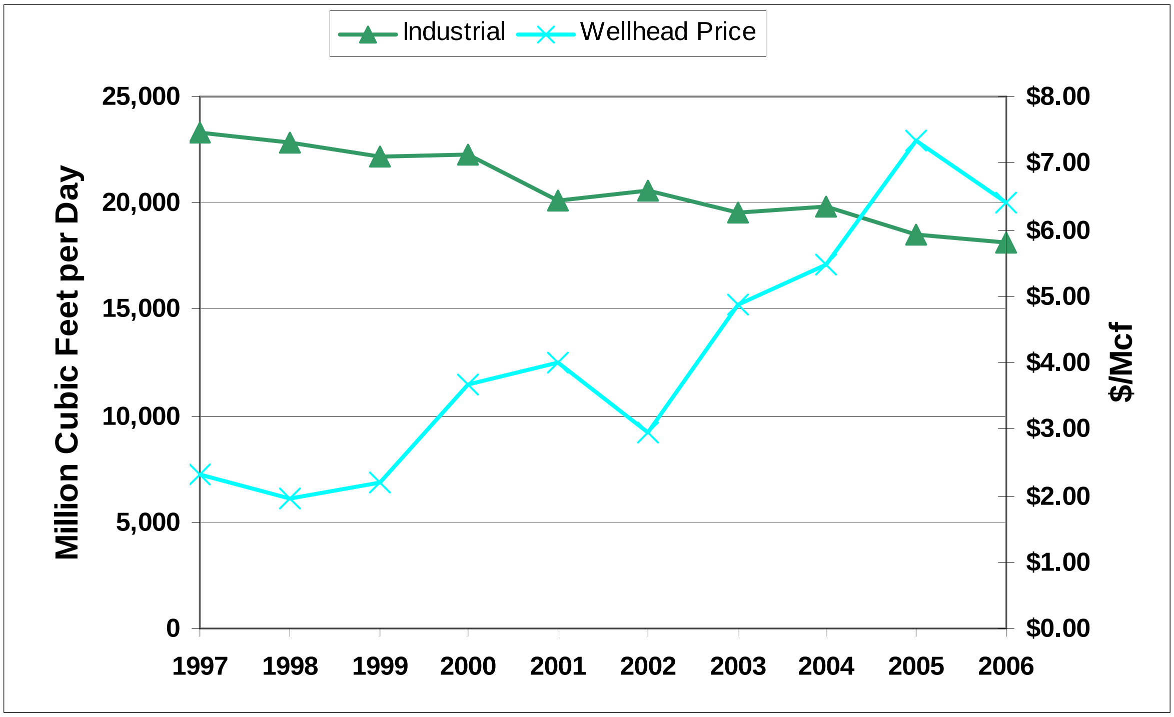
Source: Energy Information Administration

Figure 3: U. S. Commercial Consumption vs. Natural Gas Price in 2006 Dollars



Source: Energy Information Administration

Figure 4: U. S. Industrial Consumption vs. Natural Gas Price in 2006 Dollars



Source: Energy Information Administration

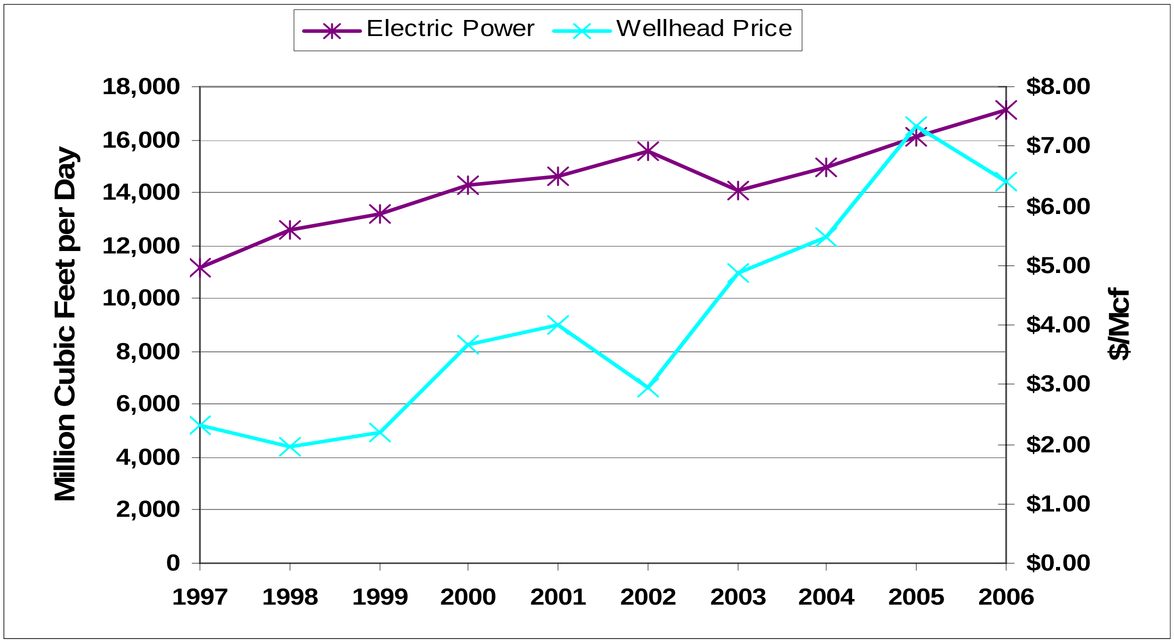
The one end-use sector with increasing natural gas use is the electric power sector (**Figure 5**). Natural gas demand increased more than 50 percent since 1997 in this sector, with an annual growth rate of over 4 percent during the last decade. This growth is caused by movement of the industry to natural gas-fired electric generation.

Canada

Natural gas demand in Canada has followed the trend set in the United States in the residential and commercial sectors. Canadian residential and commercial sector natural gas consumption increased by less than 1 percent in the past decade (**Figure 6**).

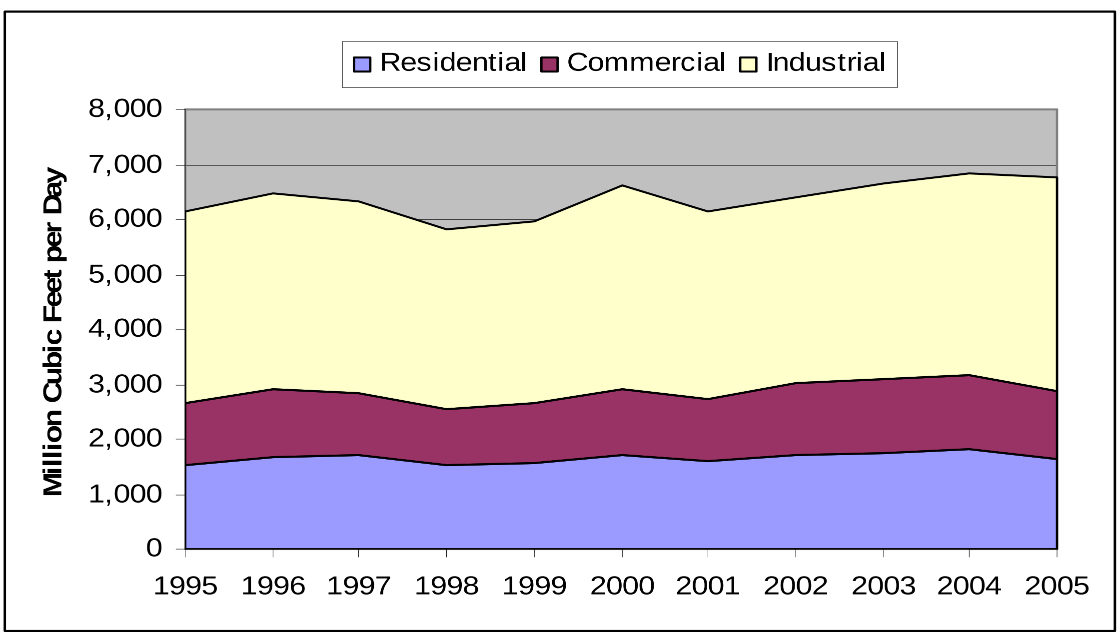
The industrial sector in Canada includes the normal industrial end users such as pulp and paper, mining and metalworking, fertilizer and cement producers, petrochemical, oil refining, bitumen mining, and the electric power sector. The higher natural gas prices have caused some erosion in natural gas demand in the combined industrial and power sectors, but this has been more than offset by an increase in natural gas demand by oil sands operations in western Canada.

Figure 5: U. S. Electric Power Consumption vs. Natural Gas Price in 2006 Dollars



Source: Energy Information Administration

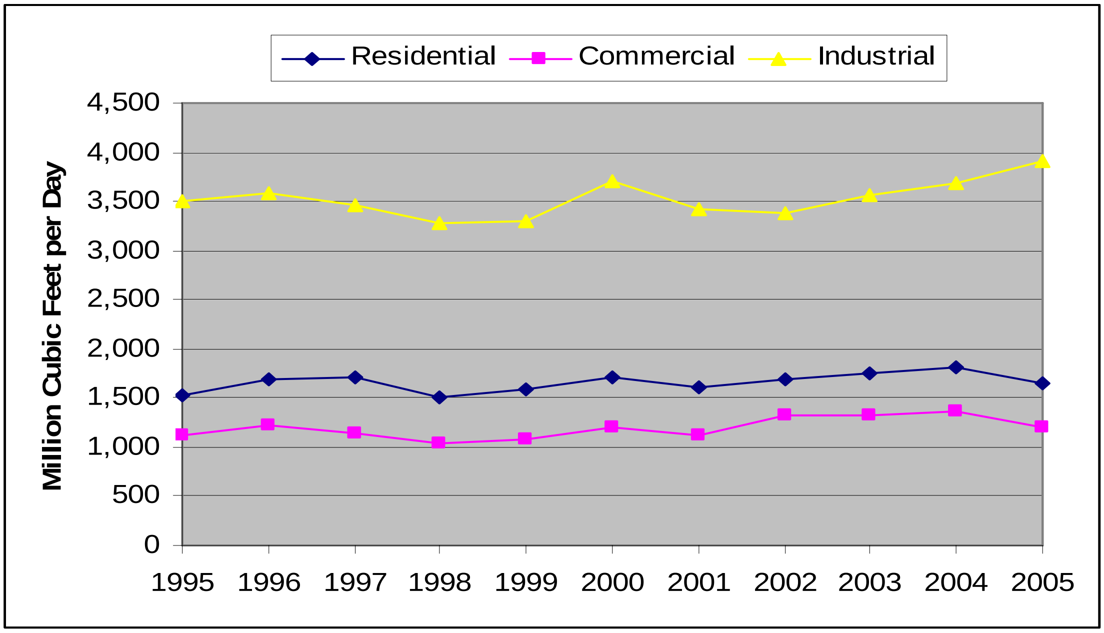
Figure 6: End-Use Consumption in Canada



Source: Natural Resources Canada, National Gas Division

Figure 7 shows the more robust growth that occurred in the industrial sector over the last decade as compared to the residential and commercial sectors. This increase in industrial growth comes primarily from oil sands operations for both mining and in situ bitumen recovery. Natural gas use for oil sands operations has increased approximately 90 percent since 2000. This growth, despite high natural gas prices, is because crude oil prices remained in the $70-per-barrel range, allowing continued expansion of oil sands operations.

Figure 7: Sector Consumption in Canada



Source: Natural Resources Canada, National Gas Division

North American Natural Gas Demand Forecast

The forecast for North America natural gas demand indicates that the demand for natural gas could increase over the next decade at an annual rate of 2.3 percent (see **Table 1**).

The United States could experience the slowest growth rate in demand, increasing at an annual rate of 2.1 percent between 2007 and 2017. Natural gas consumption for the United States for the major end-use sectors is forecast to increase from 58,780 million cubic feet (MMcf) per day to 72,112 MMcf per day.

Table 1: North American Natural Gas Consumption

	2007		2017		Gas Consumption
	MMcf per day	Population (Millions)	MMcf per day	Population (Millions)	Annual Rate of Growth, %
United States	58,780	301.1	72,112	337.6	2.1
California	5,897	37.5	6,718	42.6	1.3
Canada	8,980	33.4	11,504	37.4	2.5
Mexico	3,897	108.7	6,105	121.9	4.6
Total	71,657	443.2	89,721	496.9	2.3

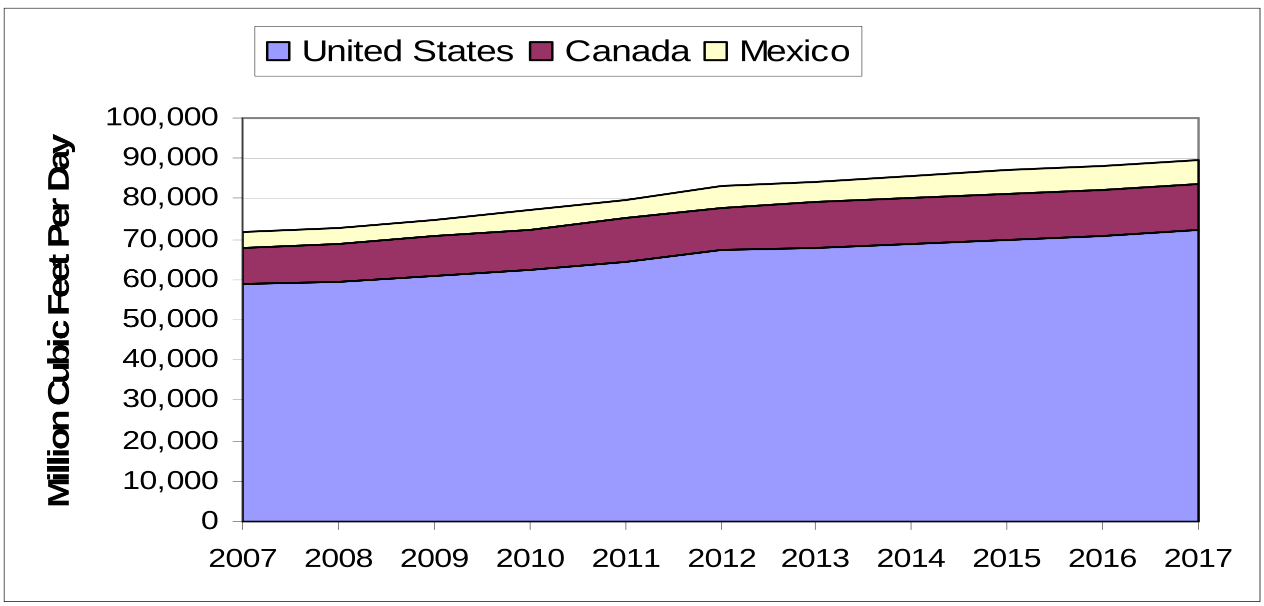
Source: California Energy Commission Staff, 2007

* Natural gas demand numbers for Mexico were developed by the National Petroleum Council and used in its 2003 report, *Balanced Natural Gas Policy: Fueling the Demand of a Growing Economy.*

* California data is included in the U. S. totals.

As seen in **Figure 8**, although the United States is forecast to have the slowest growth rate over the next decade, it will still be the dominant consumer of natural gas. The forecast indicates that the United States will continue to consume more than 80 percent of the natural gas in the North America market.

Figure 8: North American Natural Gas Demand (MMcf per day)



Source: California Energy Commission Staff, 2007

Canada's natural gas consumption is forecast to increase at an annual rate of 2.5 percent during the time horizon. Canada's natural gas consumption is expected to go from 8,980 MMcf per day in 2007 to 11,504 MMcf per day in 2017.

Mexico's annual natural gas consumption in 2007 accounts for 4.2 percent of North America's natural gas consumption. The use of natural gas in the Mexican economy is anticipated to show the largest increase, growing at an annual rate of 4.6 percent. Although Mexico is expected to have the greatest annual increase in growth, it will still only account for slightly over 5 percent of the market by 2017.

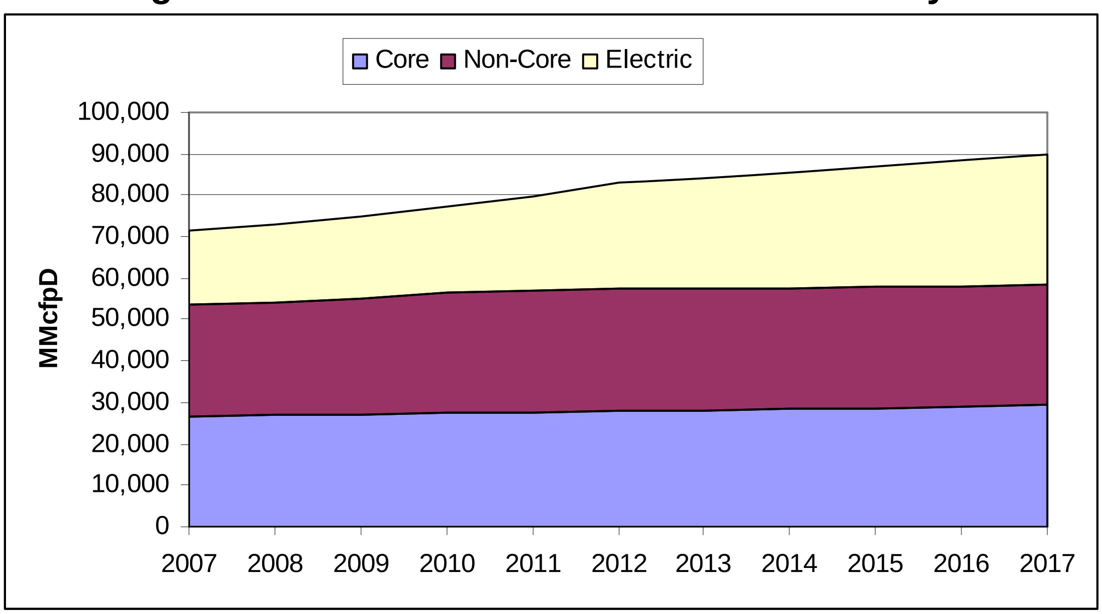
North American End-Use Sectors

To analyze the North American natural gas market, staff separated consumption into several end-use sectors. These sectors are somewhat independent of one another, with the influence of the various demand parameters differing across the sectors. The residential and commercial end-use sectors are both within the "core" sector, reflecting the fact that the consumer is not able to switch fuels.

The industrial sector, referred to as "non-core," is divided into chemical and non-chemical sectors. Some of the end users in the industrial sector have the ability to switch fuels. Other major end-user groups in the industrial sector that play a significant role in the regional demand for natural gas have been evaluated separately from the industrial sector. These end-user groups cover the natural gas demand associated with extraction of petroleum from the Alberta's oil sands and California's thermally enhanced oil recovery (TEOR).

As shown in **Figure 9**, the forecast indicates that the electric power sector is the fasting growing end use.

Figure 9: North American End-Use Forecast by Sector



Source: California Energy Commission Staff, 2007

As seen in **Table 2**, the core and non-core sectors, which include residential, commercial, and industrial users, exhibit very little growth over the forecast period. Demand growth in the residential and commercial sectors increases less than

1 percent annually. The growth in natural gas consumption in the North American market is forecast to come from the electric power sector. This sector is forecast to increase its annual natural gas consumption by more than 5 percent.

Table 2: North American Forecast of Sector Natural Gas Demand (MMcf per day)

Sectors	2007	2017	Annual Rate of Change, Percent
Core	26,775	29,259	0.8
Non-Core	26,688	29,058	0.9
Electric Power	18,194	31,404	5.6
Total	71,657	89,721	2.3

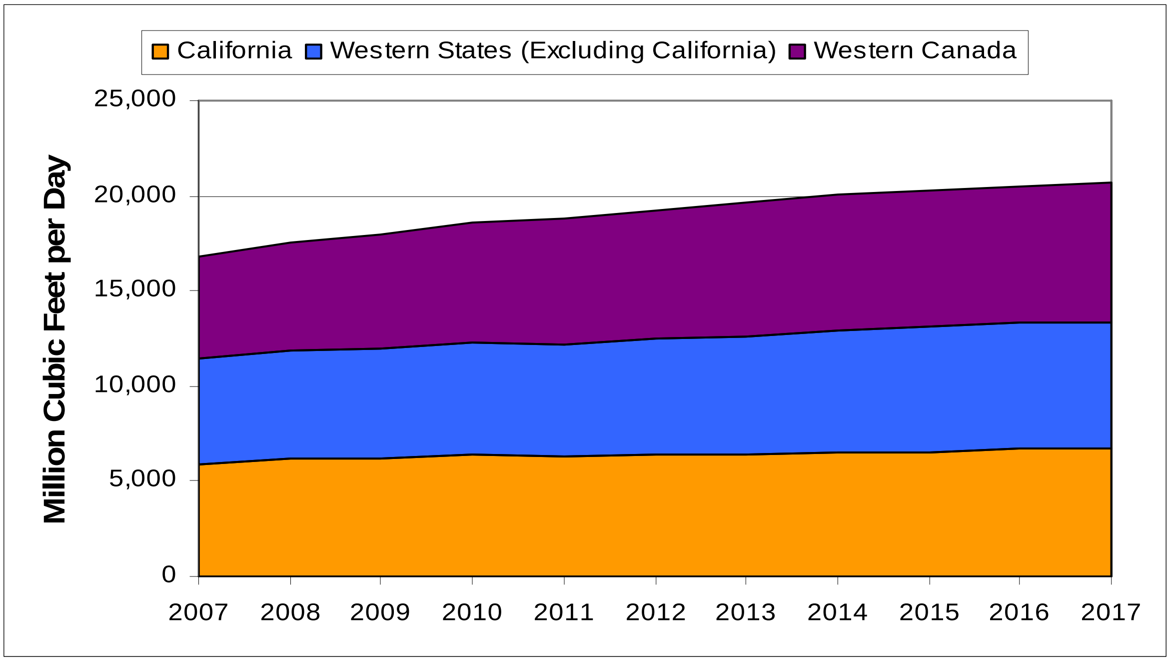
Source: California Energy Commission Staff 2007

Natural Gas Demand Forecast – Western United States, Canada, and California

Natural gas demand in the western United States and Canada is forecast to increase at an annual rate of 2 percent over the next decade. **Figure 10** shows natural gas demand for California, the western states excluding California, and Canada. Total natural gas demand in California is forecast to increase at a rate of 1.3 percent annually. Western Canada and the western states excluding California are forecast to have a higher increase in natural gas consumption. Western Canada is forecast to increase at an annual rate of 3 percent, while the western states excluding California will increase by 2 percent annually.

It is important to analyze the demand for natural gas in the western United States and Canada because the demand expected in the western states and provinces directly influences natural gas prices and the ability of California to obtain its needed gas supplies. The western U.S. region includes Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. The western Canadian provinces are Alberta, British Columbia, and Saskatchewan.

Figure 10: Natural Gas Demand in the Western United States and Canada (MMcf per day)



Source: California Energy Commission Staff 2007

Residential Natural Gas Demand

Outside California, the residential natural gas demand in the U.S. western states and Canadian provinces was based on the following parameters: price of natural gas, gross domestic product, heating degree days, population, and a lag factor to account for capital turnover. Among these parameters, hearing degree days has the greatest impact.

The natural gas forecast for residential demand in California was developed by the Energy Commission's Demand Analysis Office (see *California Energy Demand 2008-2018 Staff Draft Forecast*).

Residential natural gas demand in the West is projected to increase from 3,365 MMcf per day in 2007 to 3,706 MMcf per day in 2017 (**Table 3**). The growth in residential natural gas demand is less that 1 percent for the western United States and Canada. Canada has the lowest growth rate at 0.73 percent annually while the western states, excluding California, have the highest at 1.09 percent annually. The primary factor contributing to the differences across the various regions is population growth.

Western Canada

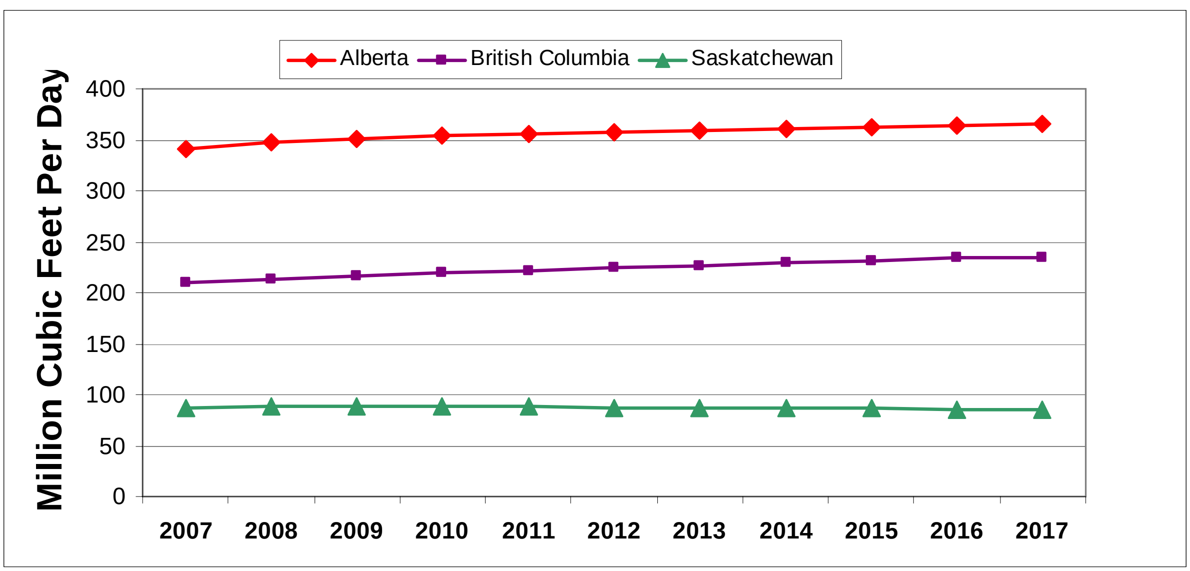
Figure 11 indicates that Alberta will continue to dominate the residential market in western Canada. Alberta accounts for approximately 54 percent of the residential natural gas consumption in the region, followed by British Columbia at 32 percent and Saskatchewan at 14 percent. Over the forecast period, Alberta's residential demand will increase at a rate less than 1 percent. British Columbia shows a faster growth in residential consumption with demand increasing by 1.2 percent annually. Saskatchewan residential consumption will remain flat.

Table 3: Residential Natural Gas Demand in the Western United States and Canada (MMcf per day)

	2007	2017	Annual Rate of Growth, Percent
Western United States and Canada	3,365	3,706	0.97
Western Canada	638	686	0.73
Western United States, Excluding California	1,345	1,499	1.09
California	1,382	1,521	0.96

Source: California Energy Commission Staff, 2007

Figure 11: Western Canada Residential Natural Gas Consumption



Source: California Energy Commission Staff, 2007

Western States Excluding California

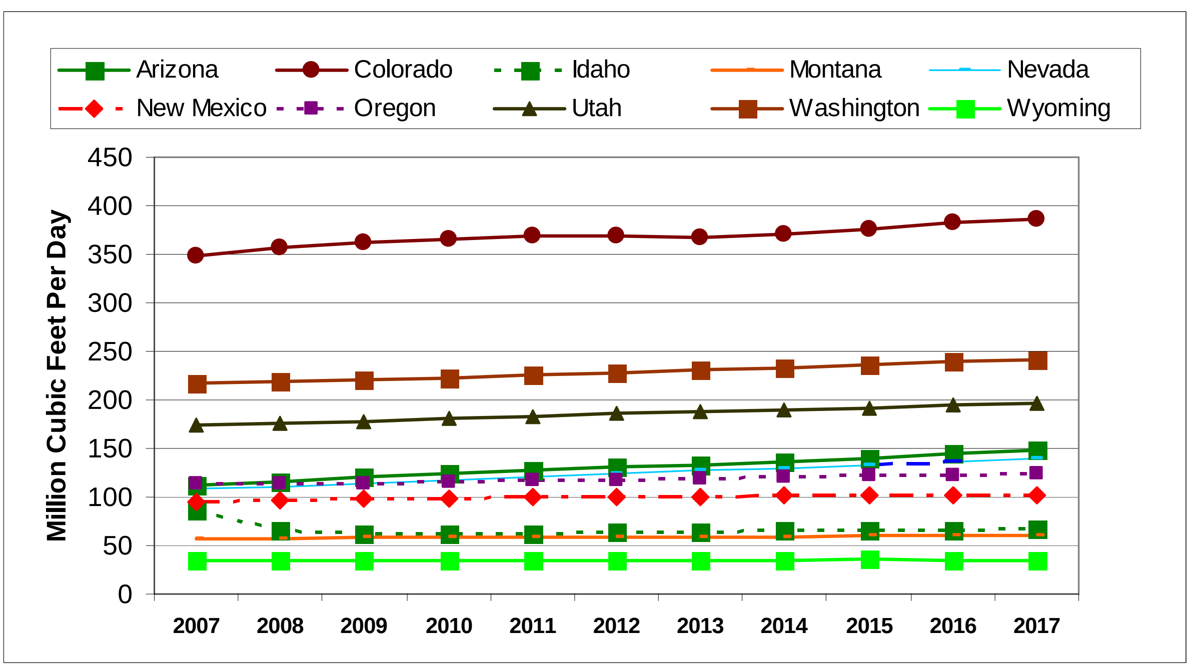
The growth in residential consumption in the western states is being driven by the increase in population, especially in Arizona and Nevada, followed by Utah and Washington. These states are forecast to have residential natural gas consumption increases greater than 1 percent annually (see **Figure 12**). Arizona's growth rate is forecasted at 2.8 percent, followed by Nevada at 2.6 percent, Utah at 1.2 percent, and Washington at 1 percent. **Figure 13** compares residential demand for the western states (with and without California) and Canada for each year of the forecast.

California

California's residential natural gas consumption is composed of space heating, water heating, and cooking. It is forecast to grow from 1,382 MMcf per day in 2007 to 1,521 MMcf per day in 2017. This represents a forecast growth rate that is slightly less that 1 percent. As shown in **Figure 13**, California will continue to dominate the residential market in the West because of the size of its residential market. The increase in residential natural gas demand in California accounts for slightly less than 50 percent of the increase in natural gas consumed by this sector in the west over the forecast period.

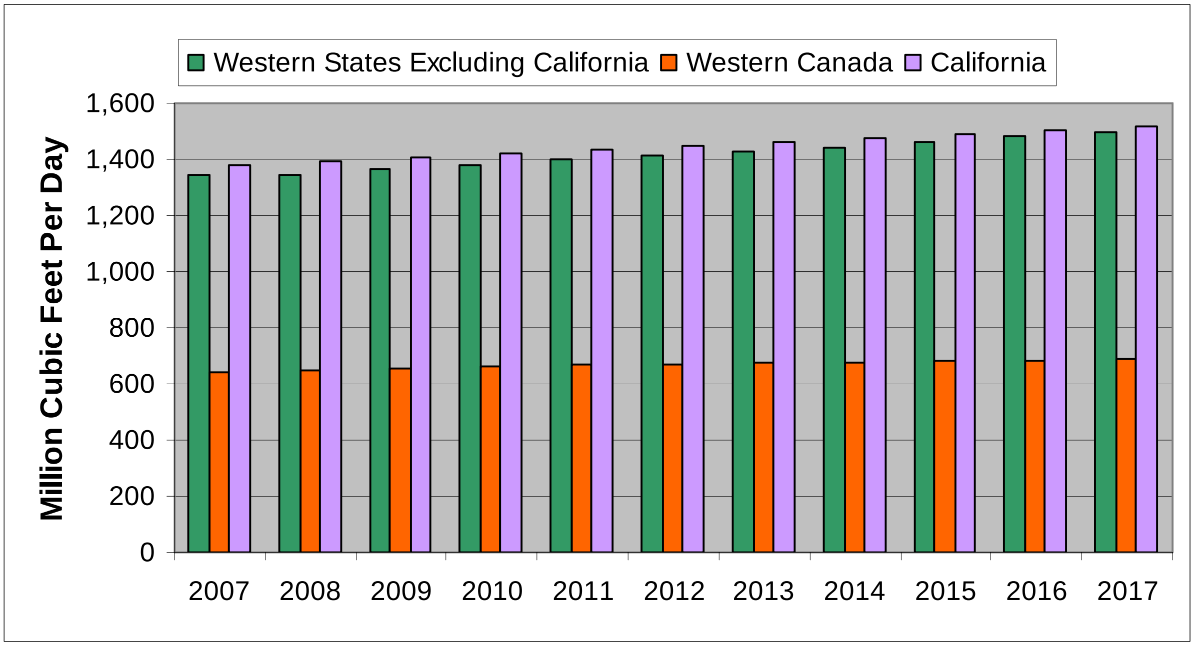
The state has three major utility service areas: Northern California served by PG&E, the Los Angeles Basin and Southern California served by Southern California Gas (SoCalGas), and the San Diego area served by SDG&E.

Figure 12: Residential Demand Western States Excluding California



Source: California Energy Commission Staff, 2007

Figure 13: Residential Demand in the Western United States and Canada



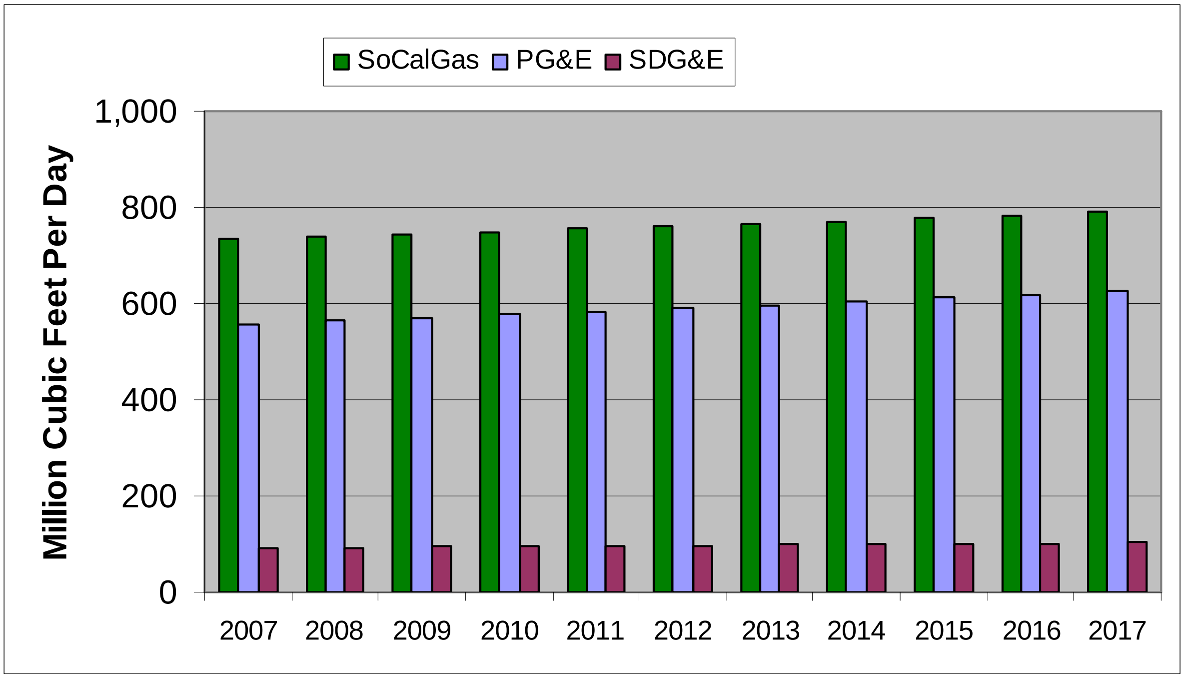
Source: California Energy Commission Staff, 2007

Over the forecast period, as seen in **Figure 14**, residential sector natural gas consumption forecast in the PG&E and SDG&E service territories will increase at a rate slightly above 1 percent. PG&E residential natural gas demand will increase from 558 MMcf per day in 2007 to 626 MMcf per day in 2017. SDG&E residential natural gas demand increases from a 2007 level of 92 MMcf per day to 104 MMcf per day in 2017. SoCalGas has the largest residential base, but the forecast indicates that it will experience the slowest growth in residential demand. SoCalGas demand is forecast to increase from 733 MMcf per day to 791 MMcf per day over the forecast period.

Commercial Natural Gas Demand

Commercial natural gas demand in the western United States and Canada, excluding California, was determined using the same parameters that were used to estimate residential demand: price of natural gas, gross domestic product, heating degree days, population, and a lag factor to account for capital turnover. Energy Commission staff developed the commercial demand for California (see *California Energy Demand 2008-2018 Staff Draft Forecast*).

Figure 14: Residential Demand in the California



Source: California Energy Commission staff, 2007

Commercial natural gas demand in the West is forecast to increase at a rate faster than the residential sector. Commercial natural gas demand is projected to increase from 2,232 MMcf per day to 2,577 MMcf per day by 2017 (see **Table 4**). Western Canada's commercial growth in natural gas demand is forecast to increase by more than 1 percent annually over the next decade. The western states, excluding California, will experience a slightly higher growth rate in commercial natural gas use at an annual rate of 1.9 percent compared to western Canada's growth of 1.4 percent annually.

Table 4: Commercial Natural Gas Demand in the Western United States and Canada (MMcf per day)

	2007	2017	Annual Rate of Growth, Percent
Western United States and Canada	2,232	2,577	1.45
Western Canada	794	910	1.38
Western United States Excluding California	842	1019	1.93
California	596	648	0.83

Source: California Energy Commission Staff, 2007

Western Canada

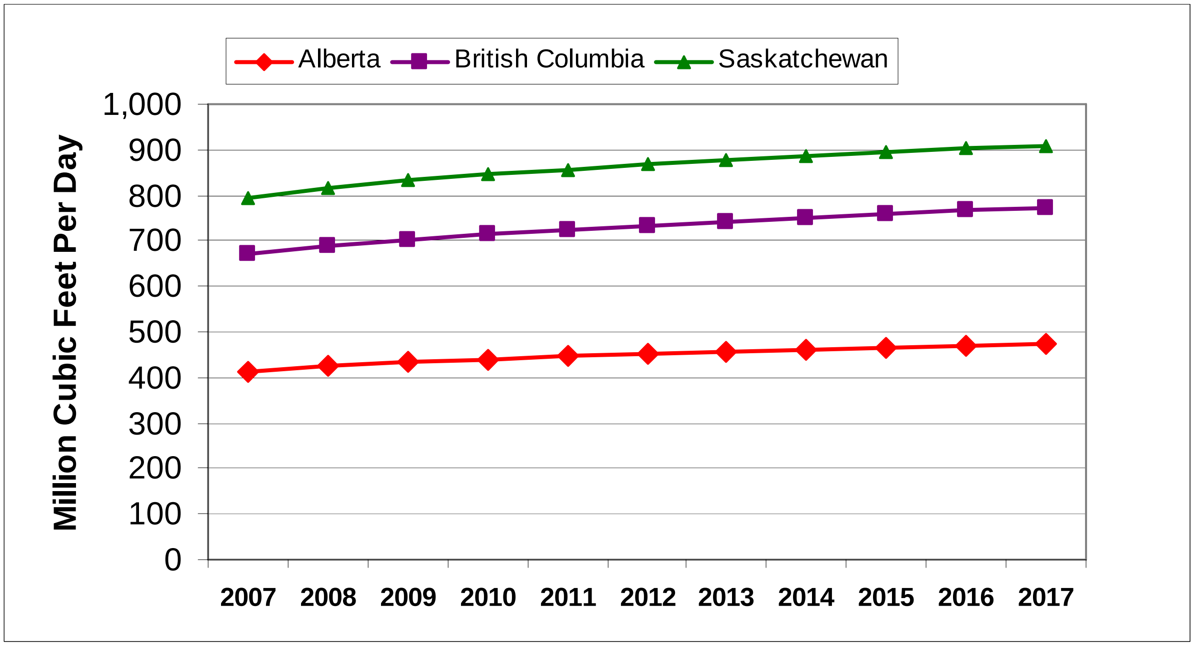
Figure 15 indicates that Alberta continues to dominate the western Canadian natural gas market. Alberta accounts for approximately 52 percent of the commercial natural gas consumption in the region, followed by British Columbia at 33 percent and Saskatchewan at 15 percent. Over the next decade, Alberta's commercial natural gas demand is forecast to increase at a rate of 1.4 percent annually. British Columbia has a slightly faster growth rate for commercial consumption at 1.5 percent annually. Saskatchewan commercial consumption increases at a slower rate of 1.12 percent annually.

Western States Excluding California

Figure 16 shows commercial demand in the western states, excluding California. The demand in commercial consumption in the western states is being driven by population growth and the rate of turn-over in capital stock. As shown in **Table 4**, commercial demand increases in the western states, excluding California, at an annual rate of just under 2 percent, increasing from 842 MMcf per day in 2007 to 1,019 MMcf per day in 2017.

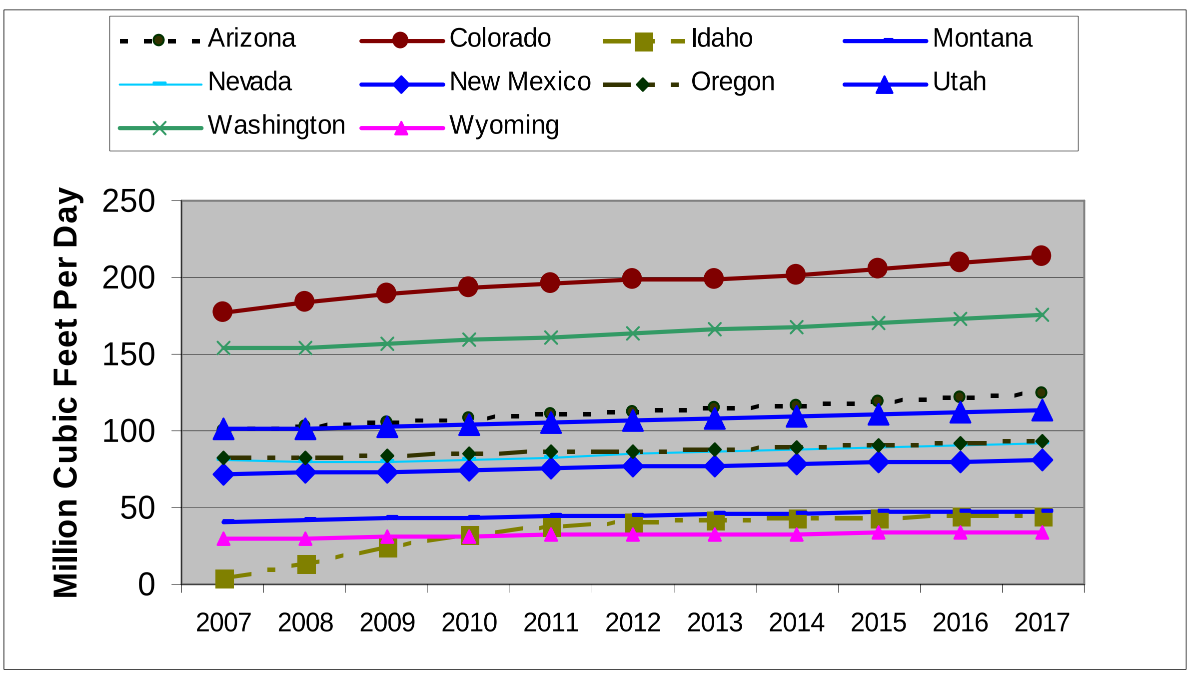
Arizona's commercial sector has the highest growth rate at 2.2 percent annually. In all of the western states outside California, the natural gas consumed in the commercial sector increases at an annual rate of 1 to 2 percent.

Figure 15: Western Canada Commercial Natural Gas Consumption



Source: California Energy Commission Staff, 2007

Figure 16: Commercial Demand in the Western States Excluding California



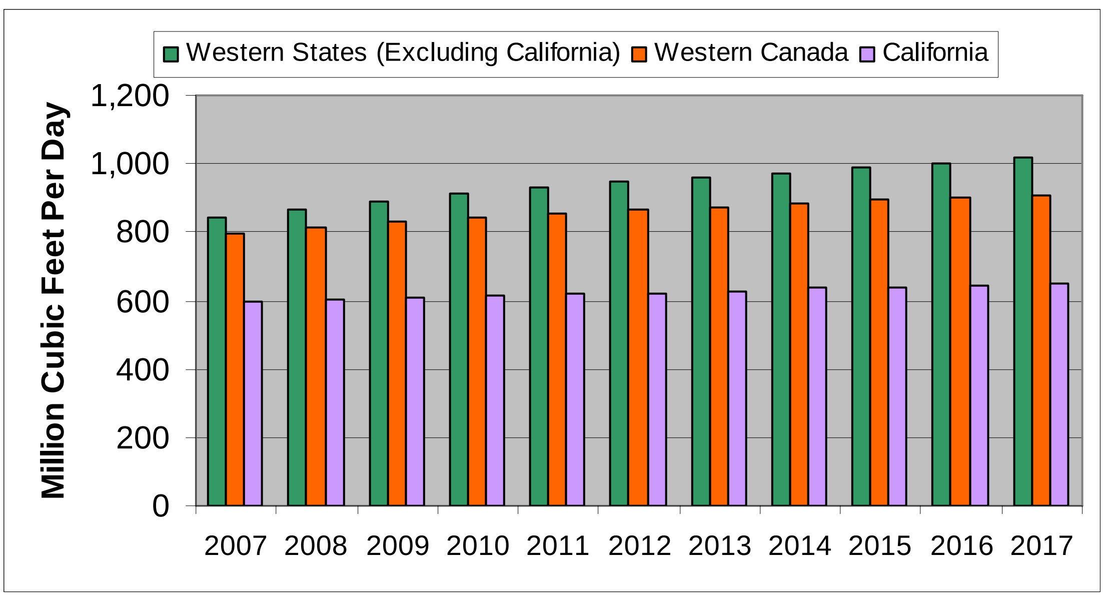
Source: California Energy Commission Staff, 2007

California

California's commercial natural gas consumption is based on the energy consumption associated with the commercial facility building type. Commercial establishments have been grouped into the following classifications: small office, large office, restaurant, retail, grocery, warehouse, refrigerated warehouse, school, college, hospital, hotel, and miscellaneous. The various commercial establishments will have a different energy use per square foot of floor space. California's commercial natural gas demand is forecast to increase from 596 MMcf per day to 648 MMcf per day by 2017. This represents an annual growth rate of 0.8 percent. California is the only western state in which commercial natural gas consumption is forecast to increase at a rate less that 1 percent annually.

California commercial natural gas demand is approximately 26 percent of the western United States and Canada (**Figure 17**) total. Western Canada consumes 39 percent while the western states outside California account for 35 percent of the commercial natural gas consumed.

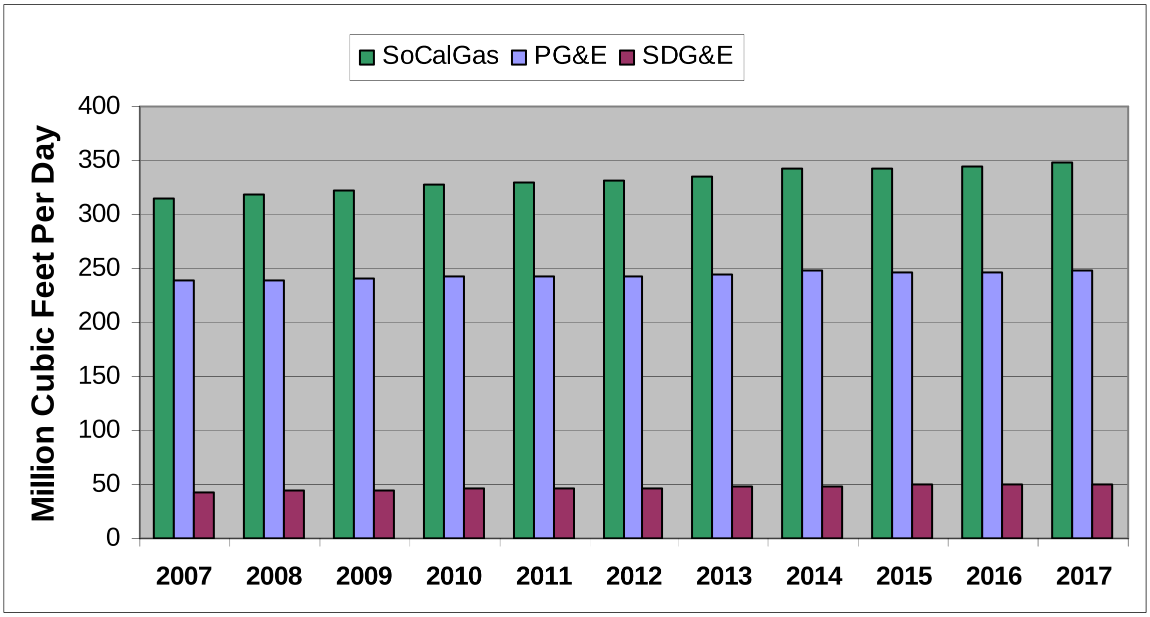
Figure 17: Commercial Demand in the Western United States and Canada



Source: California Energy Commission Staff, 2007

As indicated in **Figure 18**, commercial demand for natural gas in the state could grow at less that 1 percent annually. The SoCalGas service area represents approximately 53 percent of the state's commercial natural gas demand, followed by PG&E at 40 percent and SDG&E at 7 percent. Although the projection does not indicate significant growth in natural gas consumption for the commercial sector as a whole, there is considerable difference among the utility service areas.

Figure 18: Commercial Demand in California



Source: California Energy Commission Staff, 2007

As seen in Figure 18, PG&E commercial demand is forecast to increase from 239 MMcf per day to 248 MMcf per day over the forecast period. This represents an annual growth rate of 0.4 percent. SDG&E, with the smallest commercial sector, is forecast to have the highest growth rate at 1.6 percent annually. SDG&E commercial natural gas demand goes from 43 MMcf per day to 51 MMcf per day over the decade. SoCalGas has the largest commercial natural gas sector. Its commercial natural gas demand is forecasted to expand by 35 MMcf per day over the forecast period, increasing from 314 MMcf per day to 349 MMcf per day.

Industrial Natural Gas Demand

The industrial sector was evaluated in terms of chemical and non-chemical end users. The parameters used in the forecast of industrial demand in both the chemical and non-chemical sectors were natural gas prices, industrial production index, prices of alternative fuel (crude oil), and a lag coefficient to account for the turnover of capital equipment. The demand analysis indicated a higher sensitivity to changes in natural gas prices for the chemical end users, so the two portions of the sector are represented separately.

The Energy Commission staff developed the industrial demand for California (see *California Energy Demand 2008-2018 Staff Draft Forecast)*.

Increasing natural gas prices since the late 1990s has resulted in a significant decrease in demand for natural gas in the industrial sector. Those industrial users that had significant natural gas requirements have either moved operations to natural gas-producing regions with cheaper natural gas prices or have developed processes that use less natural gas.

Table 5: Industrial Natural Gas Demand in the Western United States and Canada (MMcf per day)

	2007	2017	Annual Rate of Growth, Percent
Western United States and Canada	4,676	4,786	0.23
Western Canada	2,136	2,221	0.39
Western United States, Excluding California	1,629	1,623	-0.03
California	912	942	0.32

Source: California Energy Commission Staff, 2007

This has resulted in a natural gas demand forecast for the industrial sector that indicates meager growth. Total industrial natural gas demand in the West is basically flat, the forecast indicating an annual growth rate of 0.23 percent annually. As indicated in **Table 5**, Industrial demand is forecast to be 4,676 MMcf per day in 2007 and increasing by 110 MMcf per day to 4,786 MMcf per day by 2017.

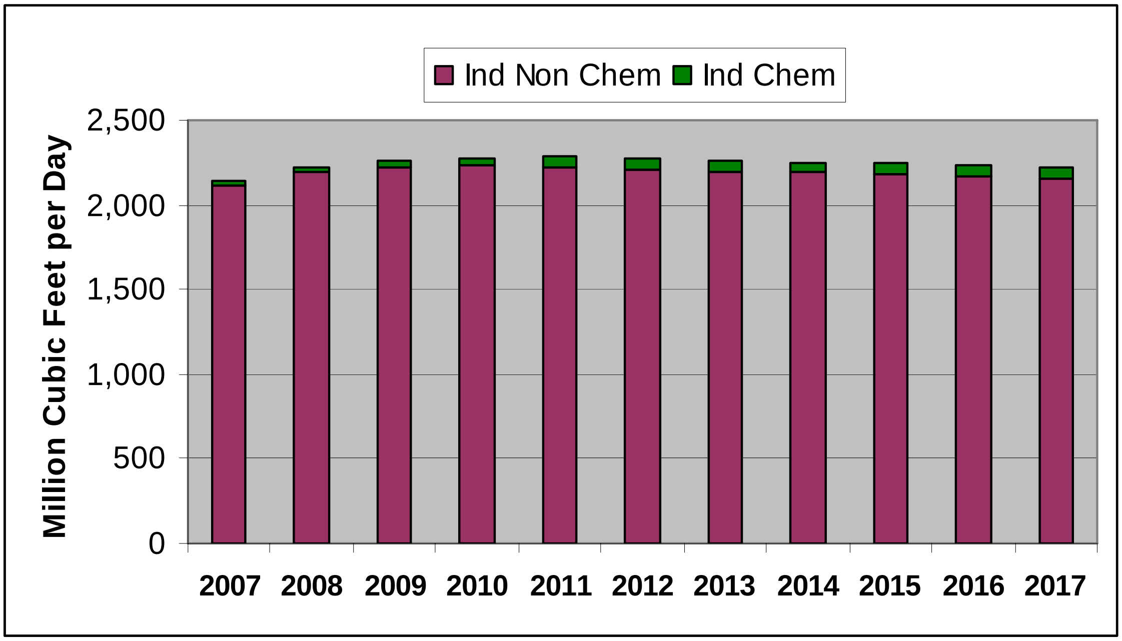
Western Canada

Canadian industrial natural gas consumption is forecast to increase by 85 MMcf per day, going from 2,136 MMcf per day in 2007 to 2,221 MMcf per day in 2017.

Canada' s industrial natural gas consumption is expected to increase in the early years of the forecast. This is attributed to a declining natural gas price. In the latter years of the forecast, the natural gas price increases to attract the necessary natural gas supplies to meet the North America natural gas demand. As the natural gas price increases, industrial consumption declines slightly (**Figure 19**). As **Figure 19** indicates, the bulk of western Canada's industrial demand is non-chemical. The chemical sector increases from 1 percent of the total industrial demand to 3 percent by the end of the forecast period.

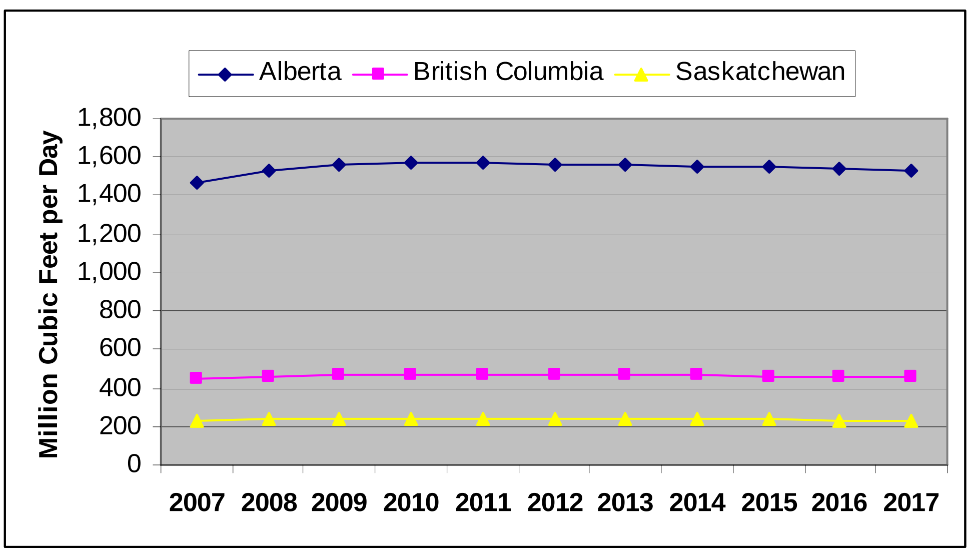
As shown in **Figure 20**, the major industrial natural gas consuming province in western Canada is Alberta. Alberta accounts for 70 percent of the industrial demand in western Canada, followed by British Columbia at 30 percent and Saskatchewan at 10 percent. The industrial demand increases slightly in the early years of the forecast as the natural gas prices decrease. Later in the forecast period, industrial natural gas demand decreases as the forecast natural gas price increases.

Figure 19: Western Canada Industrial Natural Gas Consumption



Source: California Energy Commission Staff, 2007

Figure 20: Western Canadian Provinces Industrial Natural Gas Consumption



Source: California Energy Commission Staff, 2007

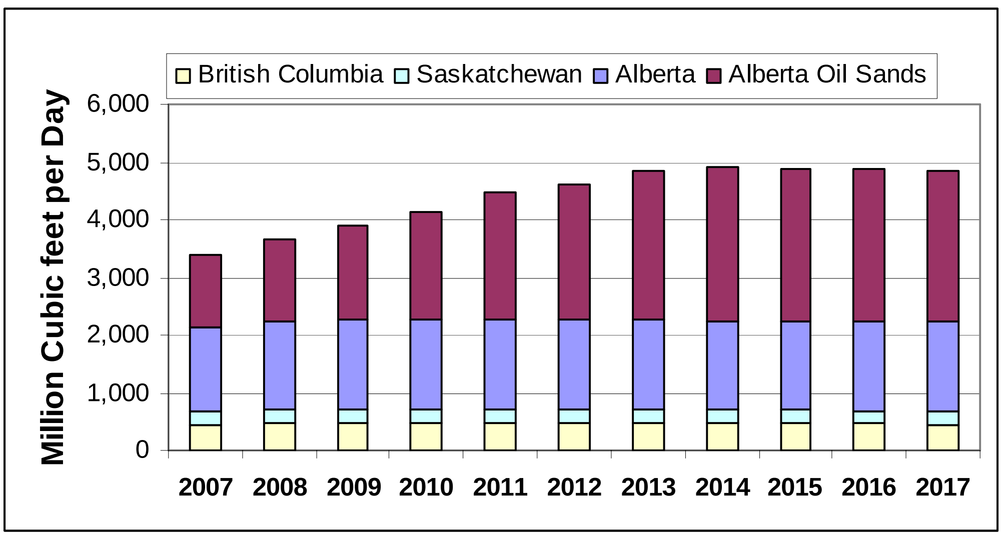
Canada Oil Sands

A great deal of natural gas is used in the process of producing bitumen (heavy crude oil) from oil sands deposits. Bitumen is a tar-like mixture of hydrocarbons too heavy and viscous to recover conventionally through a well.

Deposits close to the surface are mined and separated in a water-based slurry to remove the bitumen from the oil sands. Natural gas is used to heat water for the extraction process. Deeper deposits are recovered using one of two processes: cyclic steam stimulation (CSS) or steam-assisted gravity drainage (SAGD). Both methods use natural gas to generate steam to reduce the viscosity of the bitumen and enable its recovery.

As shown in **Figure 21**, when the natural gas demand for oil sands is included in western Canada industrial demand, the natural gas demand for this sector increases significantly. Without the oil sands, Canadian industrial natural gas demand would be flat throughout the forecast period.

Figure 21: Western Canada Total Industrial Demand



Source: California Energy Commission Staff, 2007

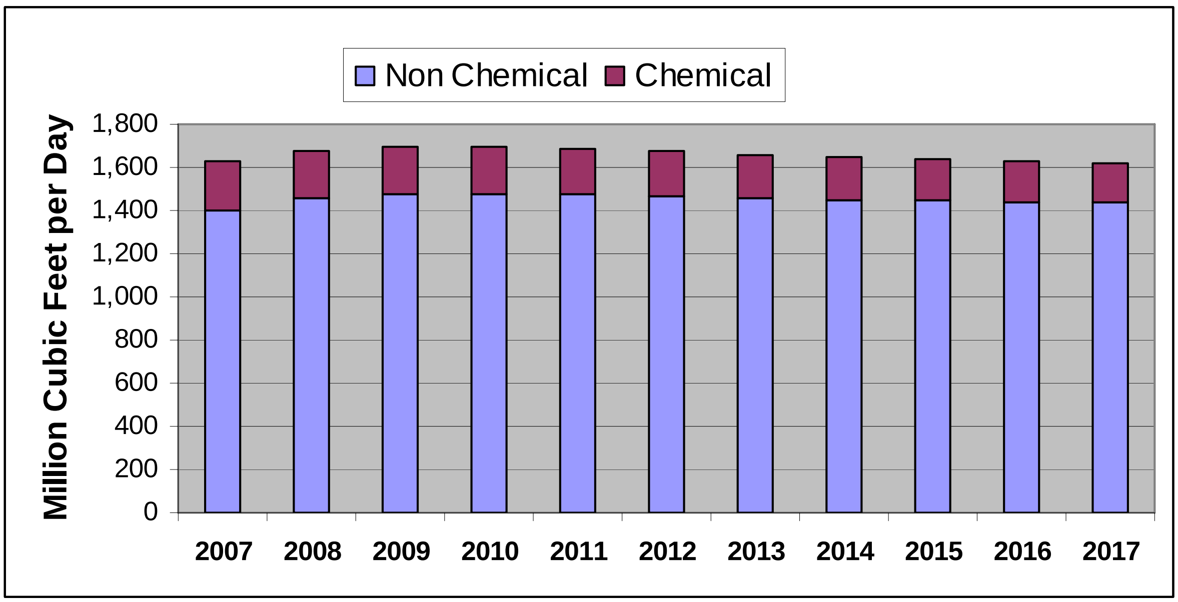
The current crude oil price is expected to generate additional development of the oil sands deposits throughout the forecast period. This bitumen extraction and upgrading process will increase natural gas demand at an annual rate greater than 7 percent. Natural gas consumed in the oil sands accounts for a third of the industrial total demand, and this will increase to more than 50 percent of the industrial natural gas consumed by 2017. Natural gas consumed in the oil sands will increase from 1,264 MMcf per day in 2007 to 2,639 MMcf per day by 2017.

Western States Excluding California

Industrial consumption in the western states excluding California is forecast to be flat over the next decade.

Natural gas consumption in the western states excluding California follows a similar trend established in the Canadian industry sector. In the early years of the forecast, natural gas prices are decreasing resulting in a slight increase in natural gas use. As natural gas prices increase in the latter years of the forecast period, industrial consumption declines slightly (see **Figure 22**). The non-chemical portion of industrial demand is a major consumer of natural gas, accounting for more than 85 percent of the natural gas consumed.

Figure 22: Industrial Demand Western States Excluding California



Source: California Energy Commission Staff, 2007

As seen in **Figure 23**, the demand follows the same trend throughout the western states, increasing in the early years of the forecast as natural gas prices decline and then decreasing in the latter years when the forecast indicates increasing natural gas prices in the North America natural gas market.

California

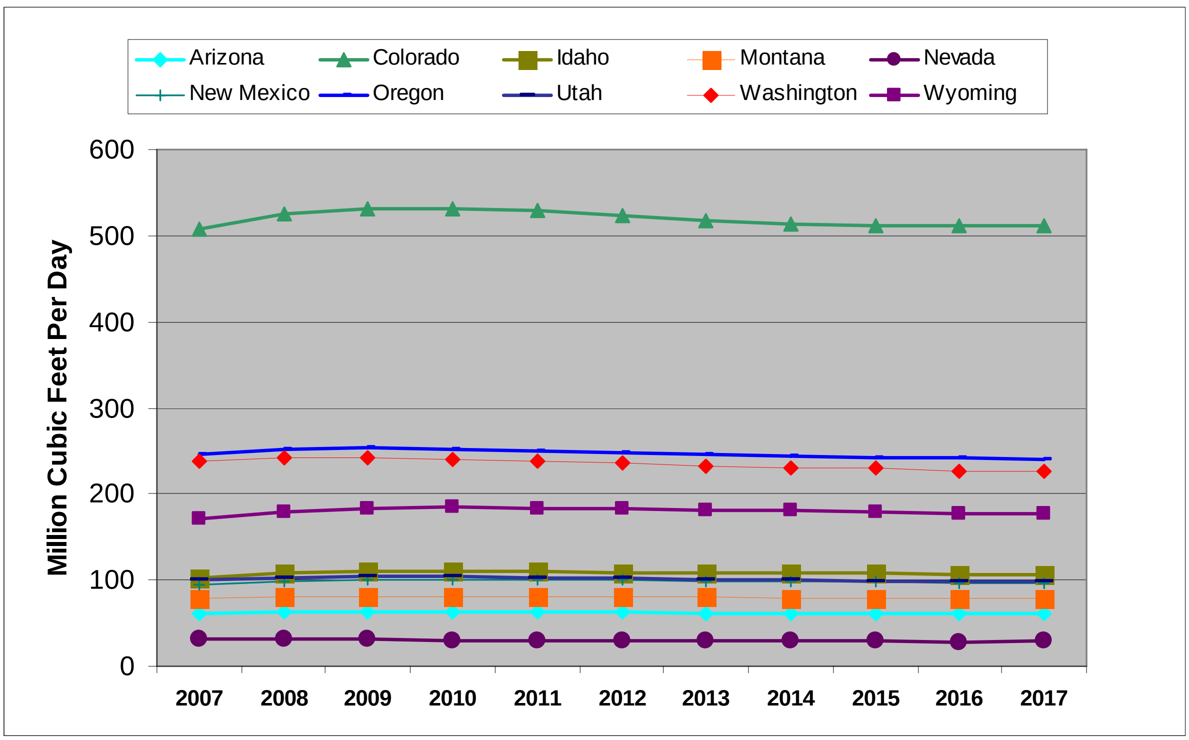
California's industrial natural gas consumption was not divided into chemical and non-chemical sectors. As shown in **Figure 24** (see below), the industrial natural gas demand forecast for the chemical and non-chemical industries indicates flat natural gas consumption over the next decade increasing slightly from 912 MMcf per day to 942 MMcf per day.

California Enhanced Oil Recovery

California enhanced oil recovery is unique to California. In California, the industrial process that accounts for the largest natural gas consumption is thermally enhanced oil recovery (TEOR) process, where steam is used to decrease the viscosity of heavy, underground oil deposits to facilitate their production.

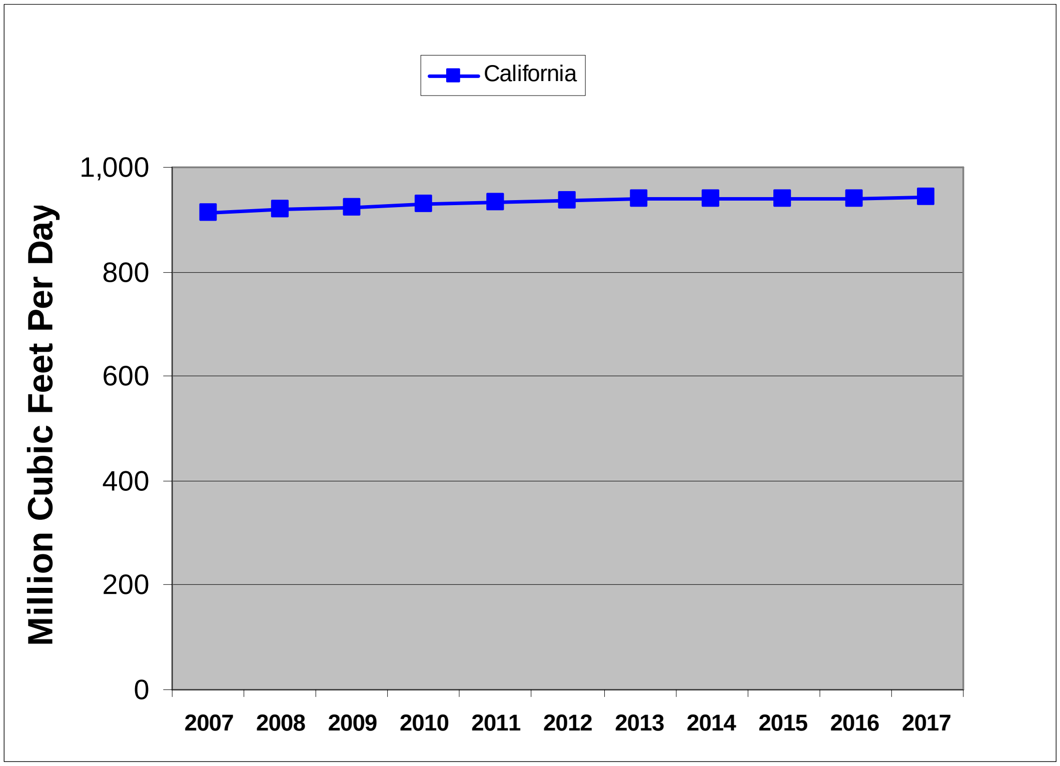
In the previous forecast, natural gas consumption for this sector was expected to decline. But increasing oil prices have resulted in the forecast for natural gas consumption associated with enhanced oil recovery to remain flat throughout the next decade.

Figure 23: Western United States Industrial Natural Gas Demand (MMcf per day)



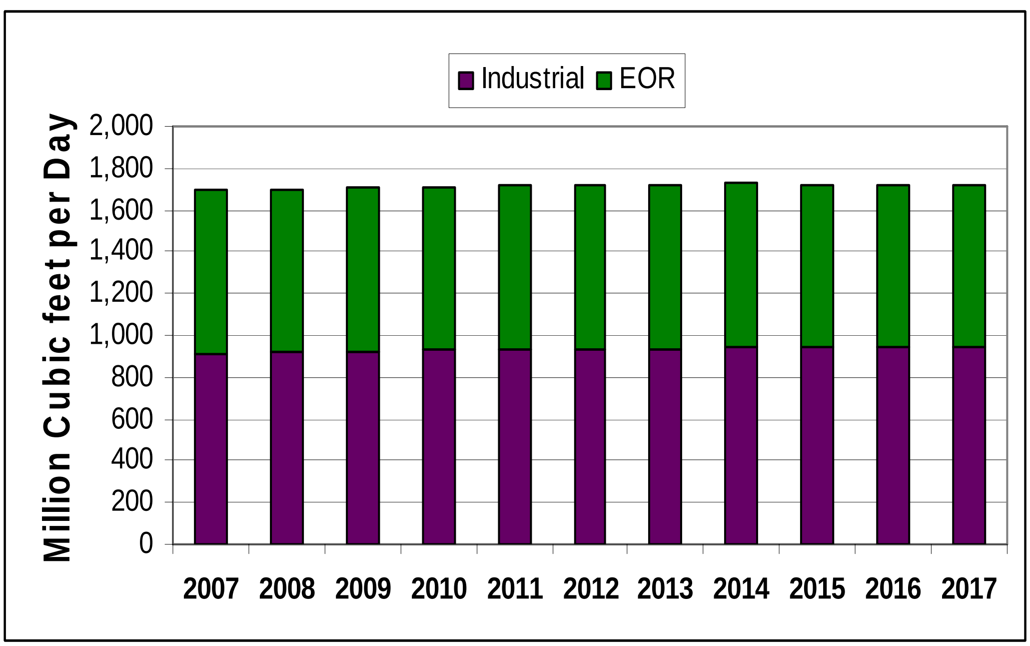
Source: California Energy Commission Staff, 2007

Figure 24: California Industrial Natural Gas Consumption



Source: California Energy Commission Staff, 2007

Figure 25: California Industrial Natural Gas Consumption with TEOR



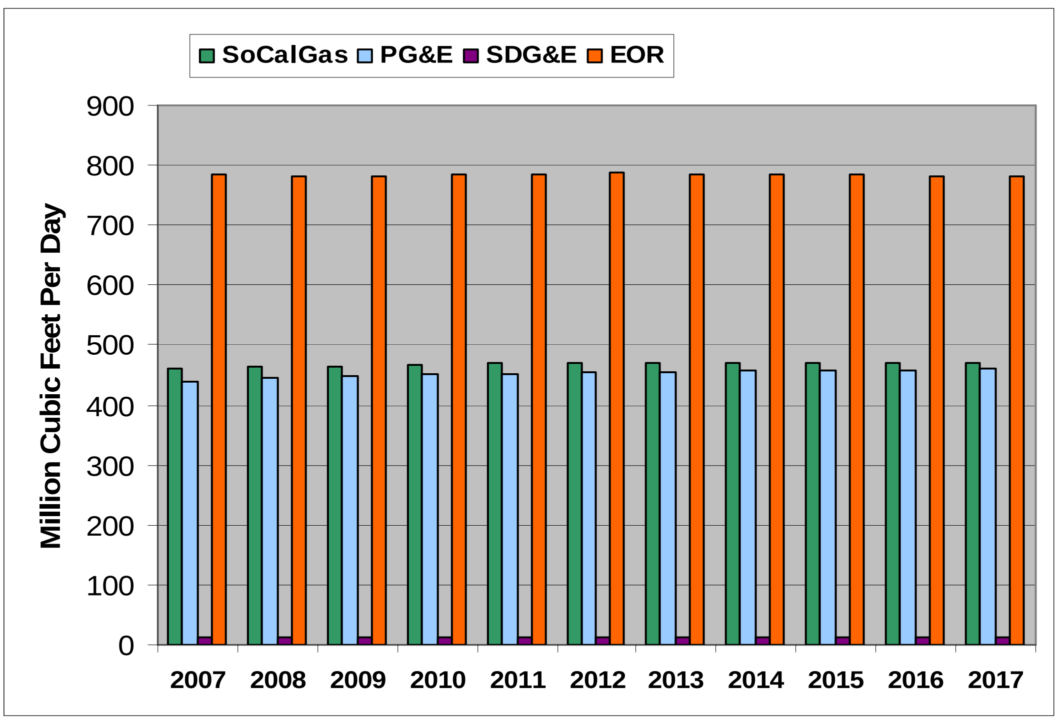
Source: California Energy Commission Staff, 2007

As observed in **Figure 25**, natural gas consumption for enhanced oil recovery is forecast to average approximately 780 MMcf per day throughout the forecast period.

Industrial natural gas consumption in the SoCalGas, PG&E, and SDG&E service territories is flat (see **Figure 26**). A major portion of the natural gas for TEOR production is delivered directly off the interstate pipelines, bypassing the utility delivery systems.

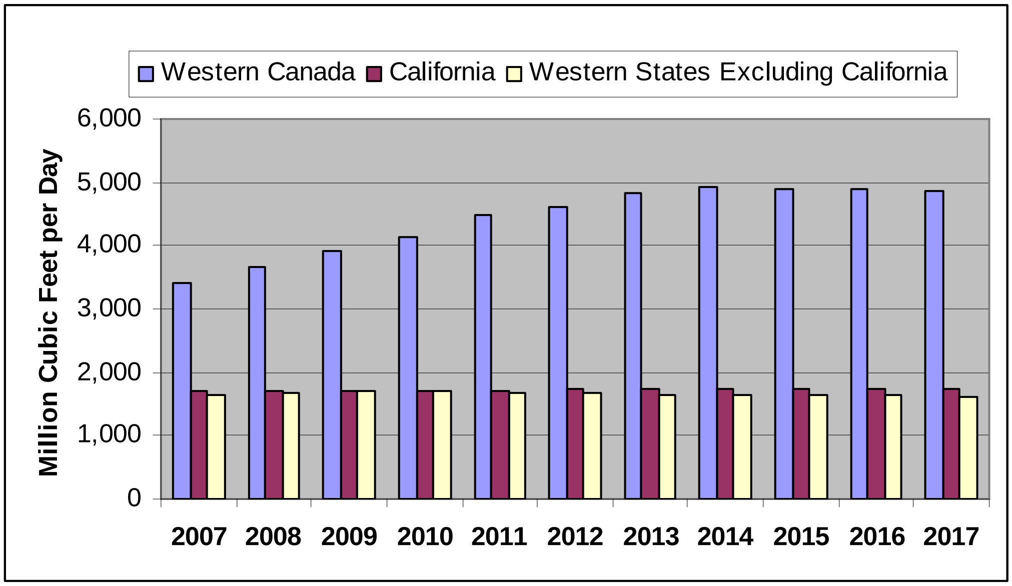
Western Canada is the primary industrial consumer of natural gas in the West. Western Canada accounts for 50 percent of the industrial natural gas consumption in 2007, increasing to approximately 60 percent of the industrial natural gas demand for the West by the end of the forecast period (**Figure 27**). The major growth in industrial natural gas use is forecast to be associated with bitumen production in western Canada.

Figure 26: California Industrial Natural Gas Consumption by Utility Service Territory



Source: California Energy Commission Staff, 2007

Figure 27: Western Regional industrial Natural Gas Demand



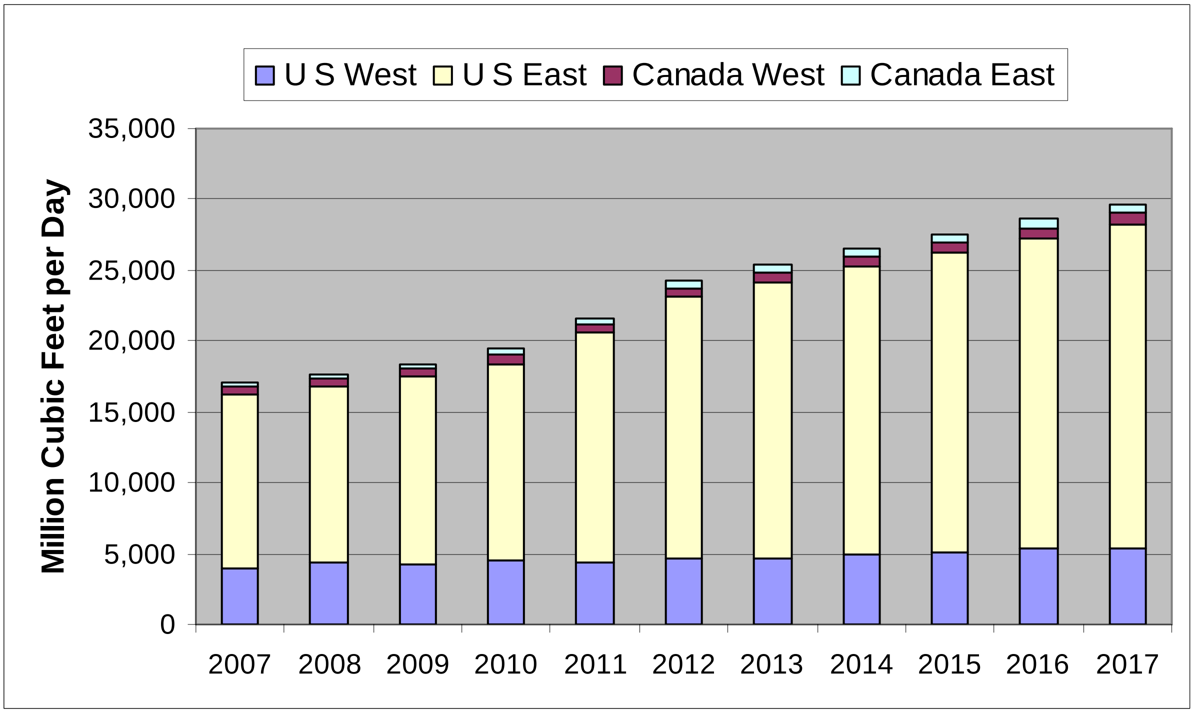
Source: California Energy Commission Staff, 2007

Electric Power Natural Gas Demand

The electric power sector natural gas demand is derived from two sources: the use of a suite of energy models developed by Altos Management Partners and the Energy Commission's Electricity Analysis Office. The forecast first uses the Altos North American Regional Gas Model and the North American Regional Electric Model to obtain the natural gas demand by the electric power industry throughout North America. The western United States and Canada natural gas demand for the electric power sector is then overlain by the natural gas demand developed by the Energy Commission's Electricity Analysis Office. The assumptions and methods for deriving natural gas demand for electricity generation in the West are described in Appendix A.

As seen in **Figure 28**, the primary growth in this sector occurs outside the West. The eastern electric power market is forecast to increase natural gas consumption by more than 6 percent annually. This growth in natural gas demand is attributed to increased use of natural gas-fired generating capacity to meet air quality and green house gas emission standards.

Figure 28: North American Electric Power Natural Gas Demand



Source: California Energy Commission Staff, 2007

The natural gas demand forecast for the electric power sector has the most robust growth of all the end use sectors. In the western states, natural gas demand for electric power generation increases at an annual rate of 3.19 percent going from 4,515 MMcf per day in 2007 to 6,178 MMcf per day in 2017 (see **Table 6**). Although the electric power sector has the strongest growth in the West, it is less than the growth being experienced in the eastern United States. The electric power natural gas demand in the East is increasing at an annual rate of 6.4 percent, giving an overall growth in the sector throughout North America of 5.6 percent.

Table 6: Electric Power Sector Natural Gas Demand in the Western United States and Canada (MMcf per day)

	2007	2017	Annual Rate of Growth, Percent
Western United States and Canada	4,515	6,178	3.19
Western Canada	563	821	3.85
Western United States Excluding California	1,730	2,530	3.88
California	2,222	2,827	2.44

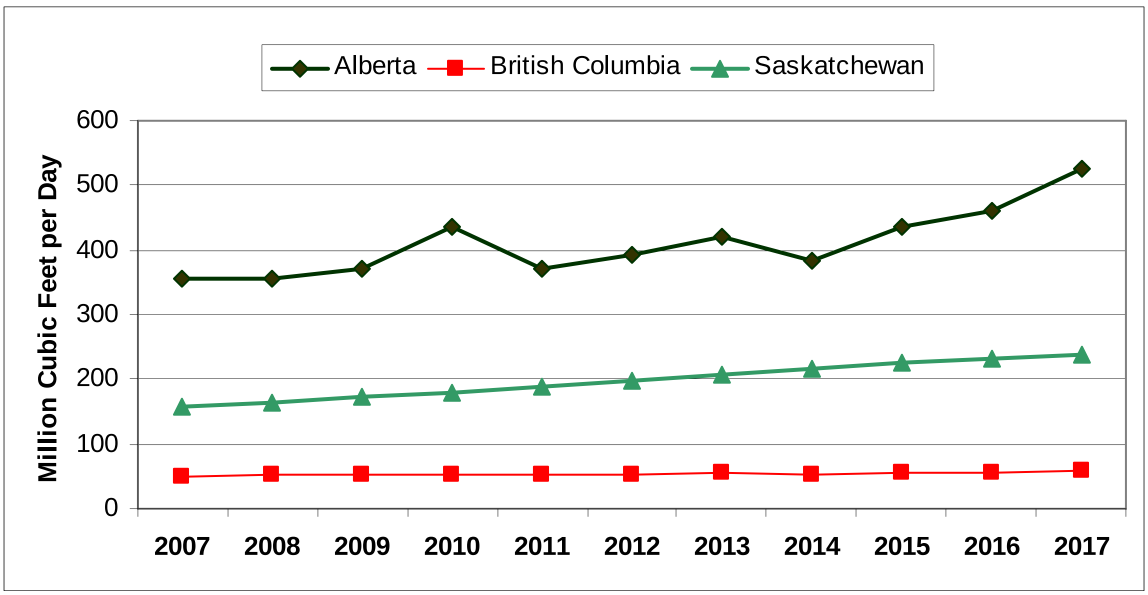
Source: California Energy Commission Staff, 2007

Western Canada

Western Canada electric power sector is forecast to increase by 258 MMcf per day going from 563 MMcf per day in 2007 to 821 MMcf per day in 2017.

Western Canada's electric power sector natural gas demand increase at an annual rate of 3.85 percent. As shown in **Figure 29**, natural gas demand for electric power generation in Saskatchewan grows the most, increasing at a rate of 4.2 percent annually. Alberta's natural gas demand for electric power increases at a rate of 2.4 percent while British Columbia natural gas demand for this sector remains flat.

Figure 29: Western Canada Electric Power Natural Gas Consumption



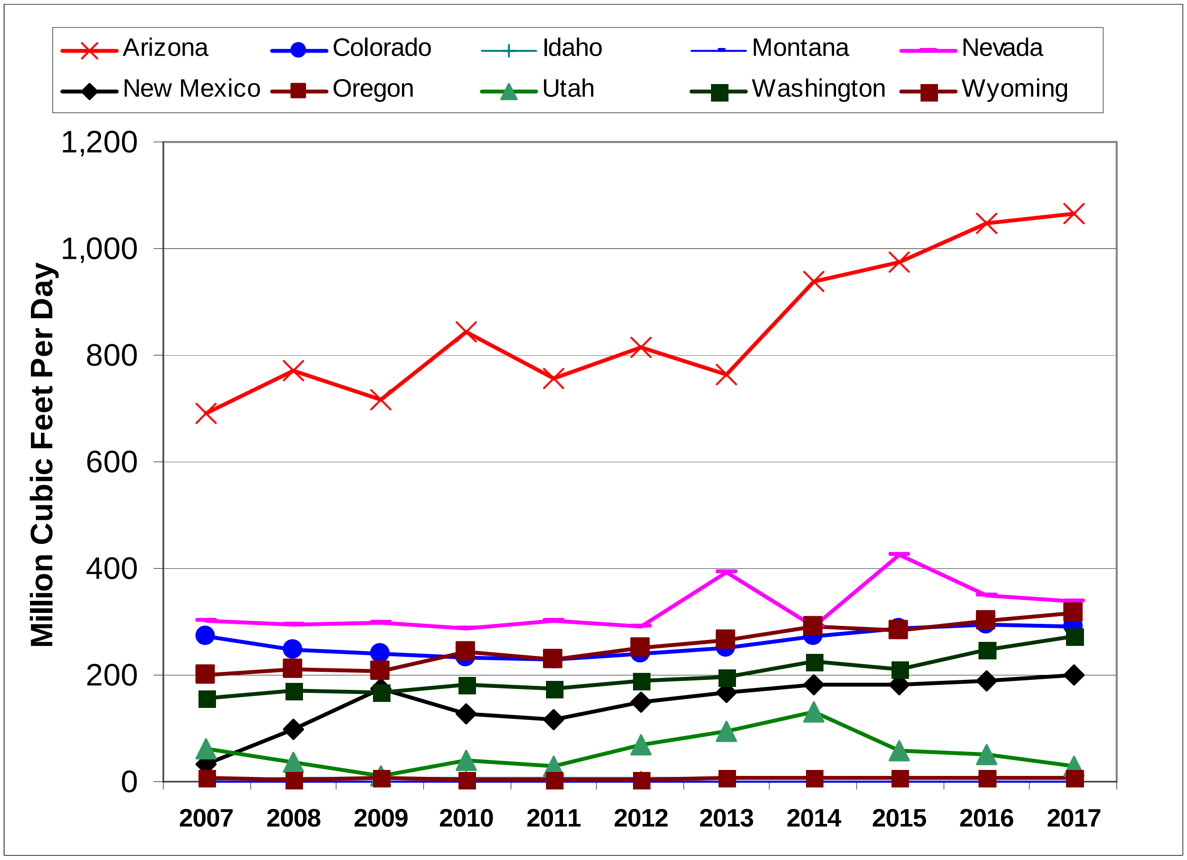
Source: California Energy Commission Staff, 2007

Western States Excluding California

Electric power natural gas consumption in the western states, excluding California, increases in line with western Canada, growing at a rate of almost 4 percent annually.

As shown in **Figure 30**, the western states, excluding California, exhibit electric power natural gas demand that varies considerably. Arizona accounts for approximately 40 percent of the natural gas consumed for electric power generation in the West outside California. The other major consumers of natural gas for electric power generation in the West are Nevada, Colorado, and Oregon. Those states with significant coal-fired generating capacity (Montana and Wyoming) consume the least amount of natural gas for power generation.

Figure 30: Industrial Demand Western States Excluding California



Source: California Energy Commission Staff, 2007

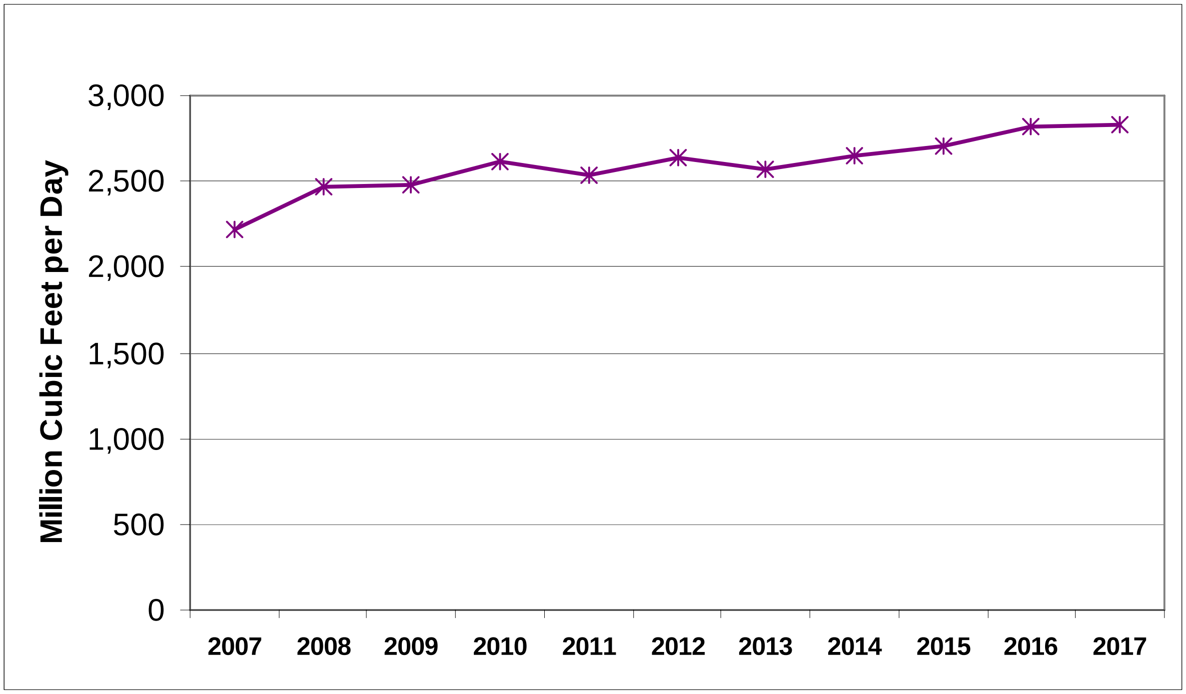
California

California's natural gas consumption for electric power is not forecast to increase as rapidly as the rest of the western states and Canada. California has just experienced a rapid expansion of its natural gas-fired generating capacity. Therefore, the state is not expected to require a significant expansion of its natural gas-fired generating base in the early years of the forecast.

Electric power sector natural gas consumption in California is forecast to increase at a rate of 2.4 percent annually, going from 2,222 MMcf per day to 2,827 MMcf per day by the end of the forecast period 2017 (see **Figure 31**). Several factors play a role in California's lower growth rate for natural gas demand in the electric power sector:

- California has built a number of natural gas-fired plants that are more efficient, producing more electricity with less fuel input.
- California has an aggressive renewables program for electric power generation.
- California advocates and promotes a strong energy efficiency policy.

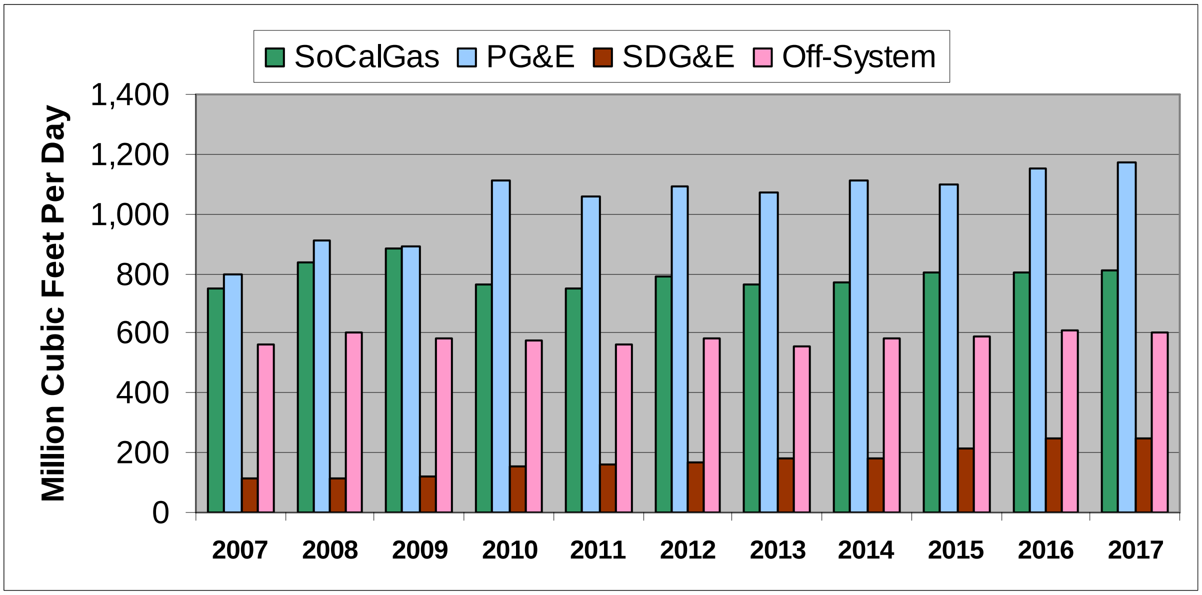
Figure 31: California Electric Power Natural Gas Consumption



Source: California Energy Commission Staff, 2007

Over the forecast period, as shown in **Figure 32** growth in the PG&E area shows the greatest increase in gas demand for electric generation increasing from 797 MMcf per day in 2007 to 1,170 MMcf per day in 2017. Natural gas demand for electric power generation in the PG&E area is forecast to increase at an annual rate of approximately 4 percent. SDG&E gas demand for power generation increases from a modest level of 115 MMcf per day to 246 MMcf per day over the next decade. This represents an annual increase of slightly less that 8 percent. SoCalGas gas demand for power generation increases slightly in the early years, but then stabilizes in the latter years of the forecast at a level just slightly above the 2007 demand. The off-system generators — those that receive gas from non-utility distribution systems — maintain a fairly constant gas demand throughout the forecast period.

Figure 32: California Electric Power Natural Gas Consumption by Service Territory



Source: California Energy Commission Staff, 2007

Appendix G, Tables G1 through G 15, details the projected natural demand for the specified demand sector.

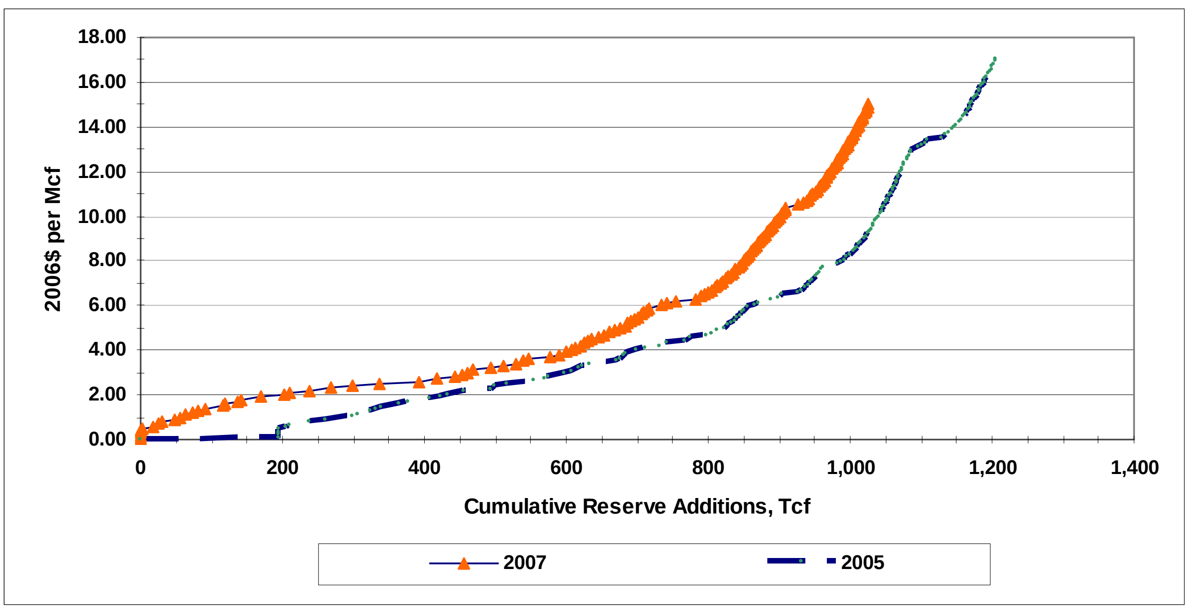
CHAPTER 3: NATURAL GAS SUPPLY

Natural gas supply projections are based on the World Gas Trade Model/North American Regional Model (WGTM/NARG). The current model contains the most recent information available on North America's natural gas resources. The estimate of natural gas resource costs began with the work done by a team of geoscientists and modelers as part of the 2003 National Petroleum Council study titled *Balancing Natural Gas Policy*. The developers of the NARG model updated these resource cost curves in 2006 to reflect accelerating exploration and development costs.

Changes in Model Since 2005

This final Natural Gas Market Assessment increased the finding and development costs to more accurately reflect current and projected future costs. The costs of some lower-cost reserves were increased, which shifted the cost curves upward and to the left. Specifically, 195 TCF of proven reserves were moved from zero capital cost to a higher capital cost (**Figure 33**). In addition, the cost curves were computed in 2006 dollars, compared to 2000 dollars in the *2005 IEPR*. Finally, natural gas from Arctic Canada and the Alaska North Slope is not expected to be available during the forecast period.

Figure 33: Comparison of Cost Curves in 2005 and 2007 Natural Gas Assessment Reports



Source: California Energy Commission Staff, 2007

There was also a significant change made since the earlier version of the 2007 *Natural Gas Market Assessment* that was presented at the June 7, 2007 workshop.

After reviewing current applications and permits for building regasification facilities in North America and considering worldwide conditions for liquefaction of natural gas, the amount of LNG imports was limited in the current assessment to approximately 14 Bcf per day, down from the 24 Bcf per day in the earlier version. The removal of that much supply caused the model to increase natural gas prices and consequently exploration, which, in turn, resulted in a relatively flat production projection as opposed to the declining trend in the June 7 version of the report.

Major Findings

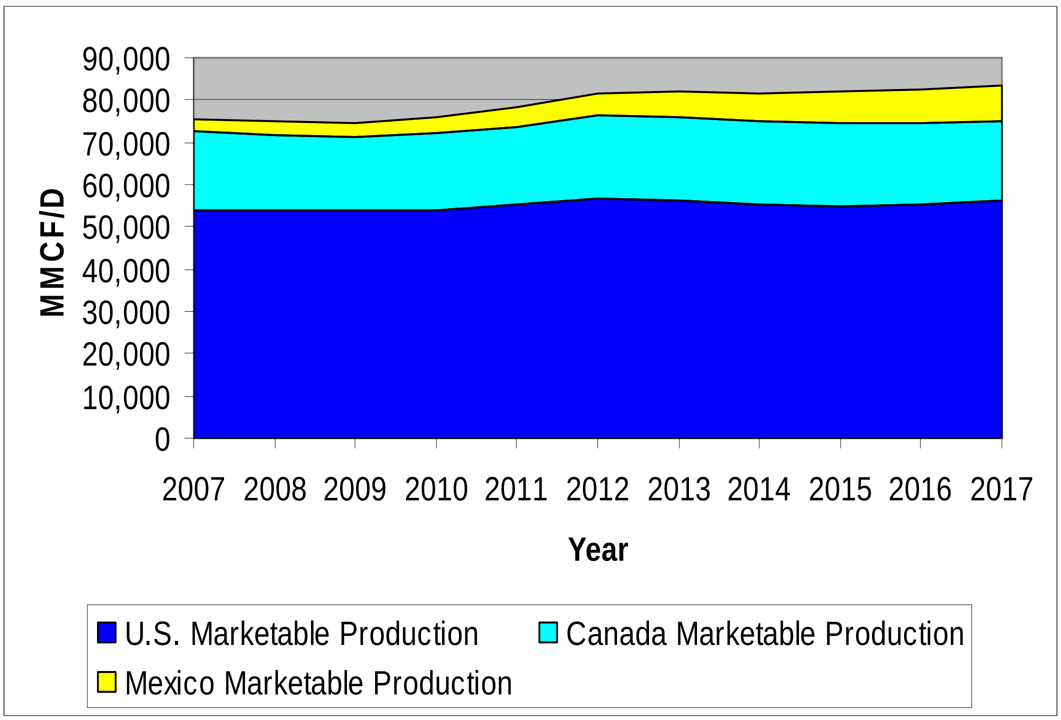
- North America's marketable natural gas production is projected to increase slightly during the forecast period. The slightly rising production trend from the preliminary version of the report is due to a reduction in the amount of LNG imported into North America. Staff restricted the flow to 14 Bcf per day in 2017, down from the previous economically derived flow of 24 Bcf per day. Removing 10 Bcf per day of LNG imports consequently raises prices to increase additional domestic exploration by enough to meet all demand.
- Natural gas from Arctic Canada and from Alaska's North Slope is assumed to be unavailable during the forecast period of 2007-2017.
- U.S. marketable natural gas production is estimated to increase slightly in the future, rising in some years and dropping in others. The change from the previously declining production trend in the June forecast results from the decrease in amount of LNG imports and increases in Canadian oil sands' use of natural gas between the preliminary report and this final version.
- The forecast projects that North America's natural gas supplies would be augmented by LNG imports, increasing from 3,945 MMcf per day in 2007 to 14,442 MMcf per day in 2017.
- The amount of natural gas produced in the Southwest, entering California at Blythe, gradually decreases during the forecast period as natural gas imported from Mexico (Costa Azul Facility) displaces domestic production from the Southwest.
- Importation of LNG is expected from Mexico into San Diego through the Transportadora De Gas Natural De Baja California (TGN) pipeline beginning in 2008. Natural gas imported from Costa Azul via the TGN to San Diego and the Baja Norte to Ehrenberg is projected to grow from zero to more than 400 MMcf per day by 2017.
- The Energy Information Administration (EIA) has revised its North American natural gas production estimates downwards for 2002-2007.
- U.S. production has been relatively flat for the last several years, even though natural gas prices and the number of natural gas wells drilled annually have both increased.

Supply Forecast Results

Figures 34 through 43 present model results for natural gas supply.

North American marketable natural gas production is projected to rise slightly during the forecast period (**Figure 34**). Neither Alaska North Slope nor Mackenzie Delta production in northern Canada is assumed to begin natural gas deliveries during the forecast period. Mackenzie production is projected to begin in 2020, and Alaska North Slope is slated to begin delivery in 2022.

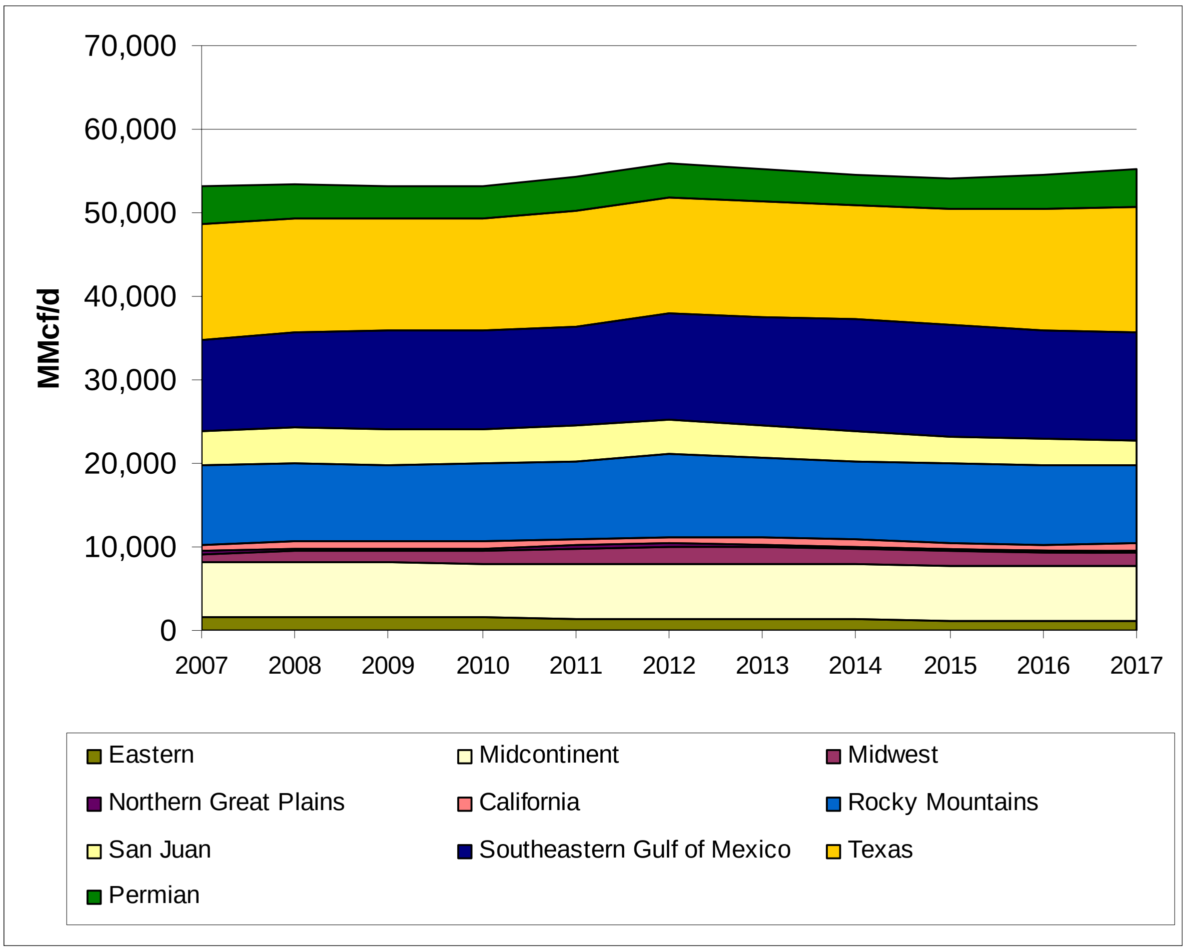
Figure 34: North American Marketable Natural Gas Production



Source: California Energy Commission Staff, 2007

U.S. marketable natural gas production is projected to remain relatively flat during the forecast period (**Figure 35**). The flat to slightly increasing production forecast is at odds with the more rapidly increasing production forecast from Energy Information Administration (EIA). However, based on flat production and despite recent high levels of drilling, the flat production scenario currently appears to be most realistic. Production records for the major producing areas important to California are provided in Appendix B.

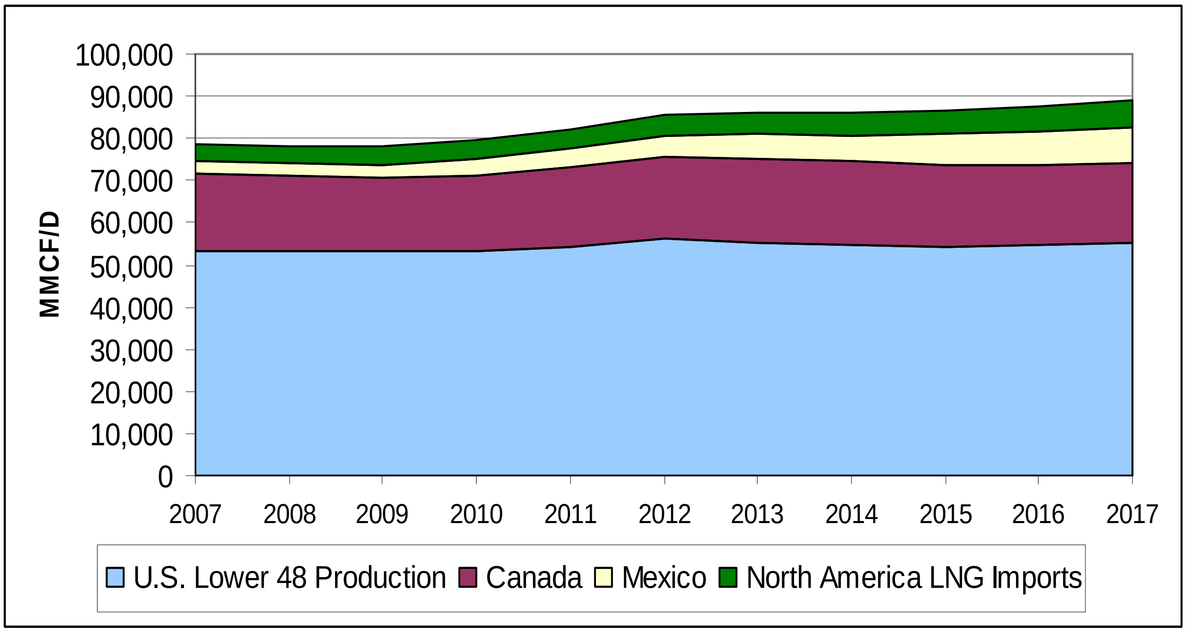
Figure 35: U.S. Natural Gas Production (Lower 48)



Source: California Energy Commission Staff, 2007

As shown in **Figure 36**, modeling results forecast that North American supply could be augmented by LNG imports, with LNG increasing from 3,497 MMcf per day in 2007 to 14,442 MMcf per day in 2017. This represents a 14 percent annual increase or a 266 percent increase over the forecast period. The dramatic increase in the quantity of LNG imported into North America is the result of flat indigenous production and delays in construction of pipelines from both the Mackenzie Delta in northern Canada and Alaska North Slope. LNG is the resource expected to supplement domestic production to meet projected demand. Appendix H provides greater details on North America's production broken out by basin.

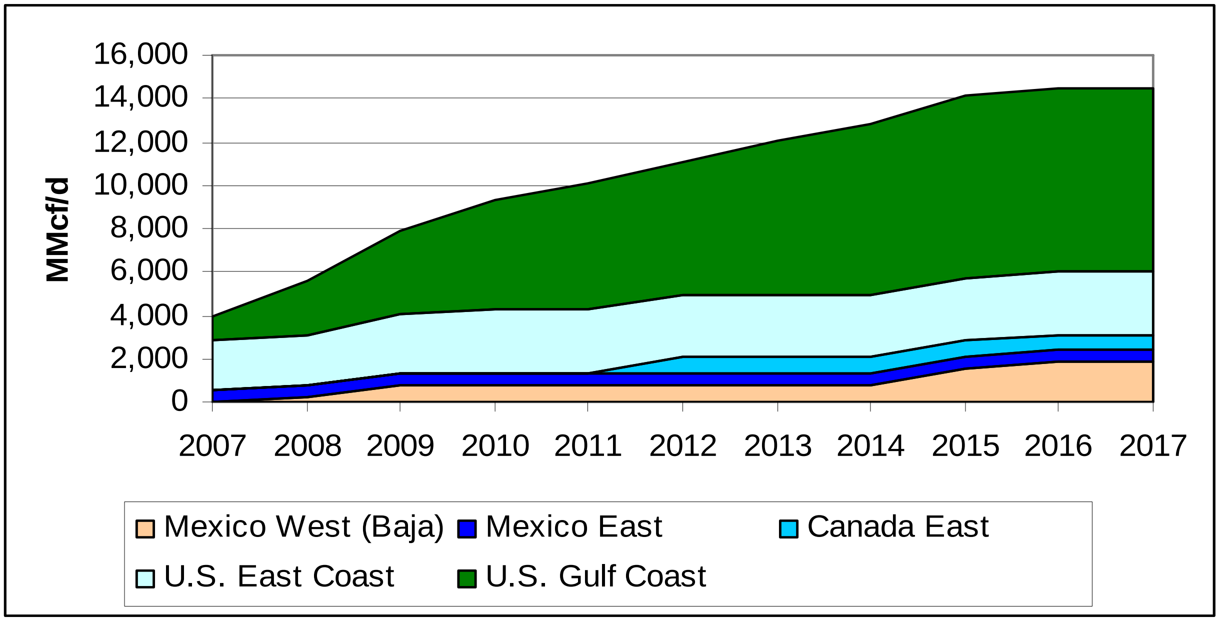
Figure 36: North American Natural Gas Supply



Source: California Energy Commission Staff, 2007

As shown in **Figure 37**, the majority of the LNG projected for importation into North America flows into the Gulf of Mexico. LNG is imported into Canada only on the east coast. In Mexico, there is one facility on the east coast already operating, and one facility (Costa Azul) on the west coast of Baja California under construction. In 2015, the model assumes an expansion of the Costa Azul facility to 2.5 Bcf per day.

Figure 37: North American LNG Imports



Source: California Energy Commission Staff, 2007

Staff decided to limit U.S. imports of LNG due to supply uncertainty created by delays in liquefaction construction, increasing costs, and geopolitical issues associated with countries that have the natural gas resources to be LNG exporters. The countries with geopolitical issues that could cause delays in LNG exporting development activity include Bolivia, Nigeria, Iran, Russia, and Venezuela. These uncertainties in the LNG supply chain were identified in the Jensen Associates report. The uncertainties associated with the potential to restrict new liquefaction capacity are expected to cause companies that have proposed or permitted regasification capacity in North America to either delay construction or cancel construction plans.

Based on these uncertainties, staff decided to impose regasification capacity constraints on the North American market. The regasification capacity used in the report was based on those facilities that are under construction and those that are permitted with a high likelihood of construction. Staff used data from the Federal Energy Regulatory Commission (FERC) current listing to obtain information on the status of those firms that had applied for permits. Only those firms currently permitted were included in the regasification database.

The construction status and timing for completion of the permitted regasification facilities in North America was evaluated base on the firms' press releases and a review of the construction time associated with facilities that have recently began operation.

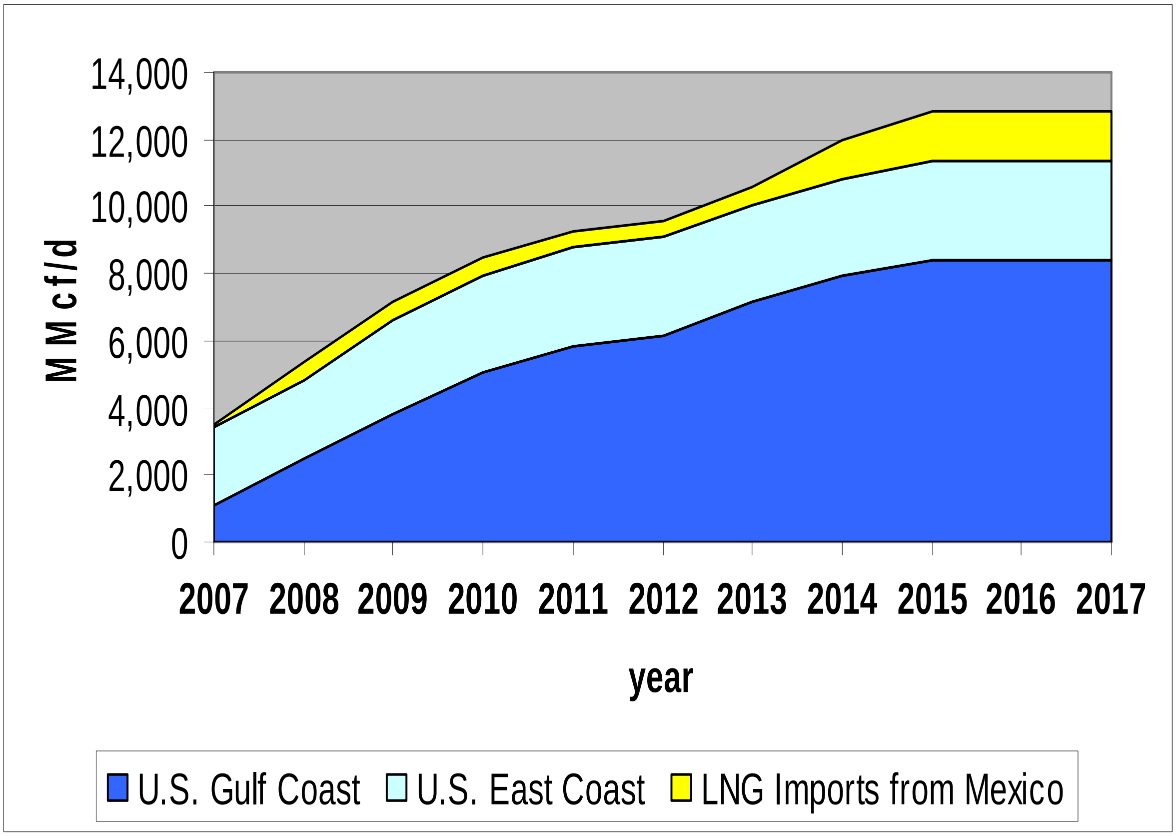
This review of North America's regasification capacity resulted in staff adding regasification capacity over the forecast period based on staff's evaluation of when the facilities would come on-stream and the expected operating capacity. The operating capacity was based on historical operating capacity of regasification facilities in the United States, Western Europe, and the Pacific markets.

U.S imports of LNG are projected in this forecast to increase significantly: 14 percent annually and 266 percent overall (**Figure 38**). As shown in the chart above, the majority of LNG is forecasted to come into the U.S. Gulf Coast. Other LNG imports enter the East Coast and from Baja California, Mexico. Because the reference case assumes that no LNG terminals are built on the West Coast during the forecast period, the West Coast of the United States has no direct imports of LNG. However natural gas will be imported by pipeline into San Diego and at Blythe Ehrenberg from the Costa Azul LNG facility located in Baja California, Mexico. Appendix I provides a breakdown on regasified LNG production for all terminals in North America.

Natural gas produced in the Southwest, entering California at Blythe, is projected in the reference case to diminish gradually during the forecast period as natural gas imported from Mexico displaces domestic production from the Southwest (**Figure 39**). Imports from Canada could also fall from about 1,312 MMcf per day to about 957 MMcf per day. Importation of LNG is also expected from Mexico into San Diego through the Transportadora de Gas Natural (TGN) pipeline beginning in 2008. Gas imported from Mexico into the San Diego area is projected to grow from 0 to just over 400 MMcf per day by 2017 to meet demand.

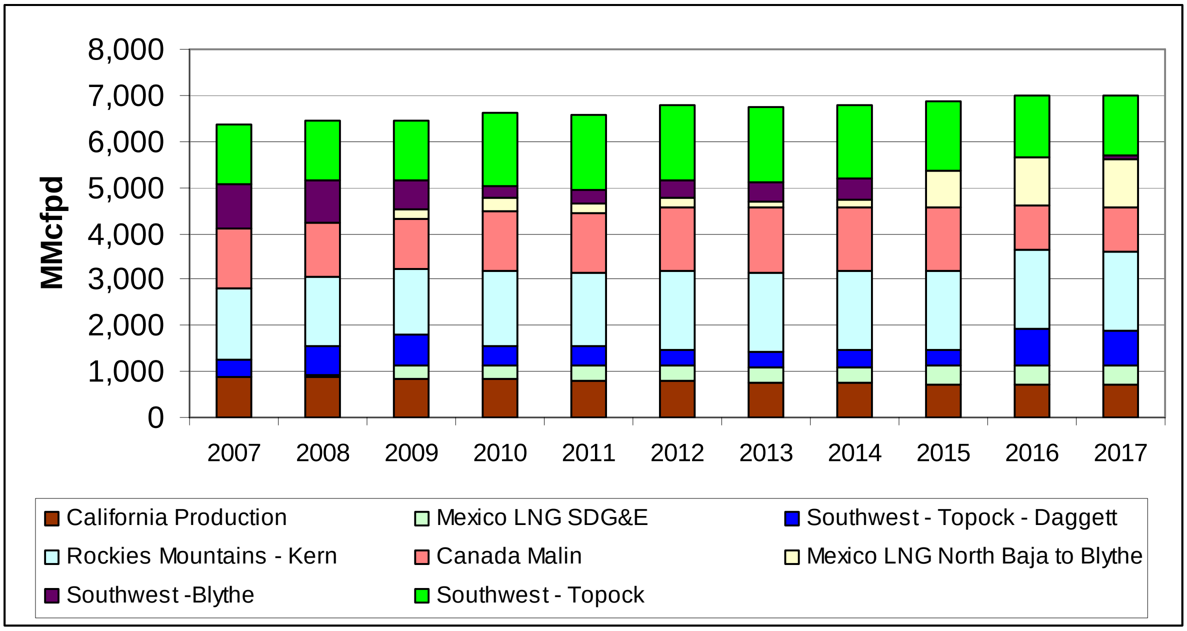
Supply from the Rocky Mountains remains relatively constant throughout the forecast period, increasing by about 1 percent per year and 12 percent overall.

Figure 38: U.S. LNG Imports



Source: California Energy Commission Staff, 2007

Figure 39: Sources of Natural Gas Supply for California[3]



Source: California Energy Commission Staff, 2007

Appendix J, Tables J-1 through J-5, details the supply-demand balance for each utility, for overall non-utility, and for total California.

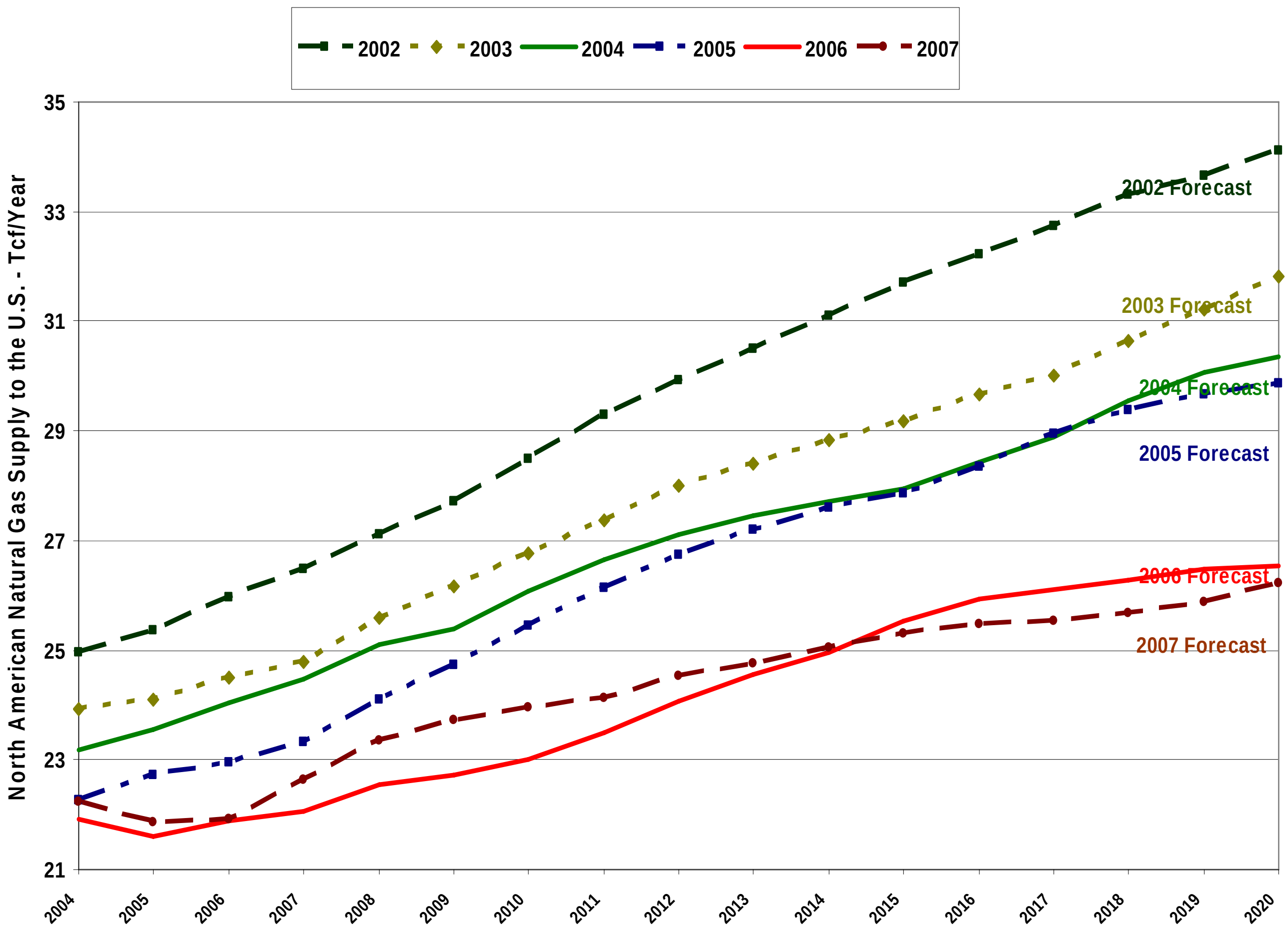
EIA's natural gas supply forecasts have been revised downward in each *Annual Energy Outlook* report since 2002. These downward revisions reflect the realization by industry and government that the supply of natural gas in North America is not as large as previously thought.

The production of natural gas in North America has recently been the subject of much speculation. The reliability of domestic and Canadian supplies is a key factor to understand the future natural gas market in North America. There are many indications that North American production is not sufficient to meet demand without increasing prices and that alternative sources of natural gas will be needed in the forecast period to contain natural gas price increases. The revised/final case has 10 Bcf less than the preliminary case and the extra 10 Bcf are met with North American supply.

3 The model balances supply and demand in all regions annually. Therefore, the model results account for pipeline losses.

Figure 40 demonstrates the downward revision of projected North American natural gas supply.

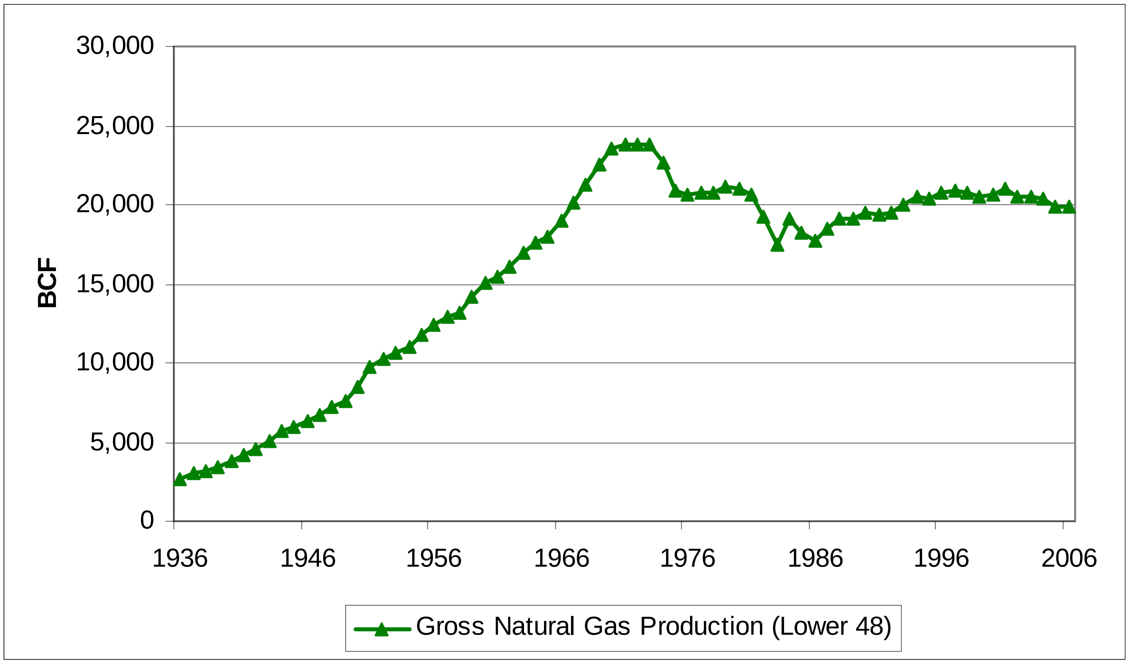
Figure 40: DOE EIA Natural Gas Supply Forecasts in North America



Source: *EIA Annual Energy Outlook*, 2001 through 2007

As shown in **Figure 41**, annual gross natural gas production first peaked in 1971 at 23,860 Bcf, in tandem with oil production. Since then, it declined through the early 1990s before rising steadily and peaking again in 2001 at 21,073 Bcf. Much of this increase was due to the increase in unconventional production such as coal bed methane and shale gas. Since 2001, production has been in a slight decline.

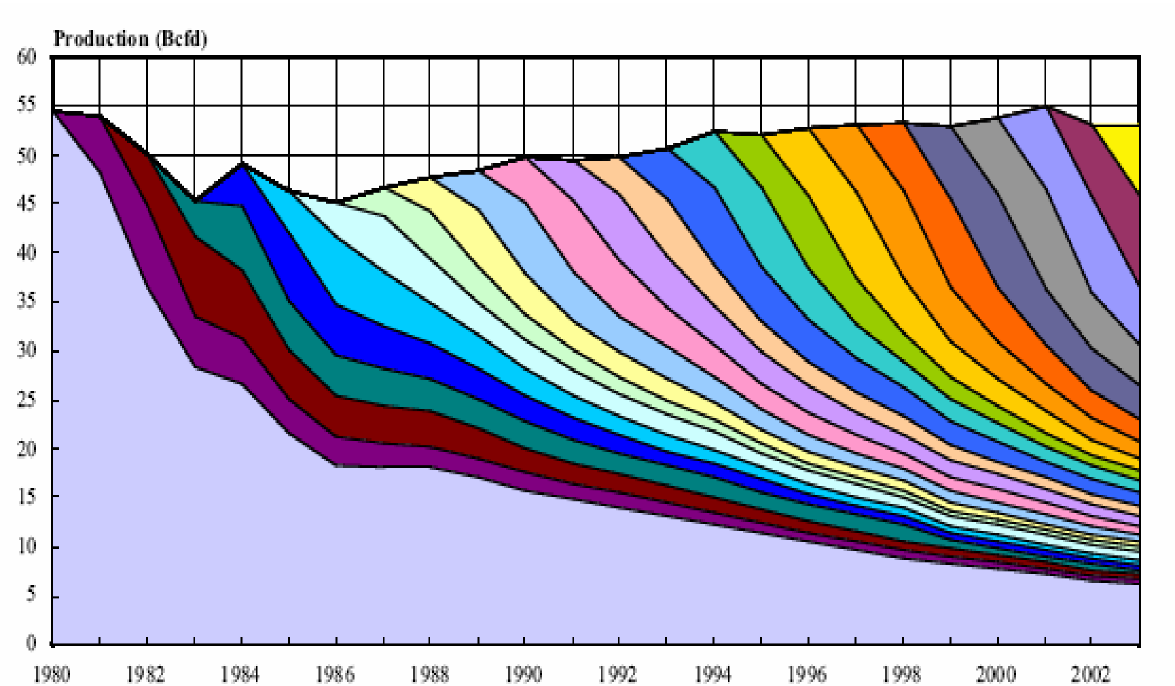
Figure 41: U.S. Gross Natural Gas Production 1936–2006



Source: EIA

Figure 42 shows how production has declined over time. Each color band represents the production history for wells drilled in that year. Notice how the color-coded space representing each year is steeper than the year before. This has two important implications. First, in each year more production is needed just to replace production that used to be produced by wells drilled in previous years. Second, in each year the initial production and subsequent production of the average well drilled that year will be less than the production history of wells drilled in previous years. This can be observed in the thinner tails of newer wells. One consequence of the declining performance of U.S. natural gas wells is that an ever increasing number of wells must be drilled just to attempt to maintain production.

Figure 42: Decline of Production over Time for Natural Gas Wells Drilled from 1980 through 2002

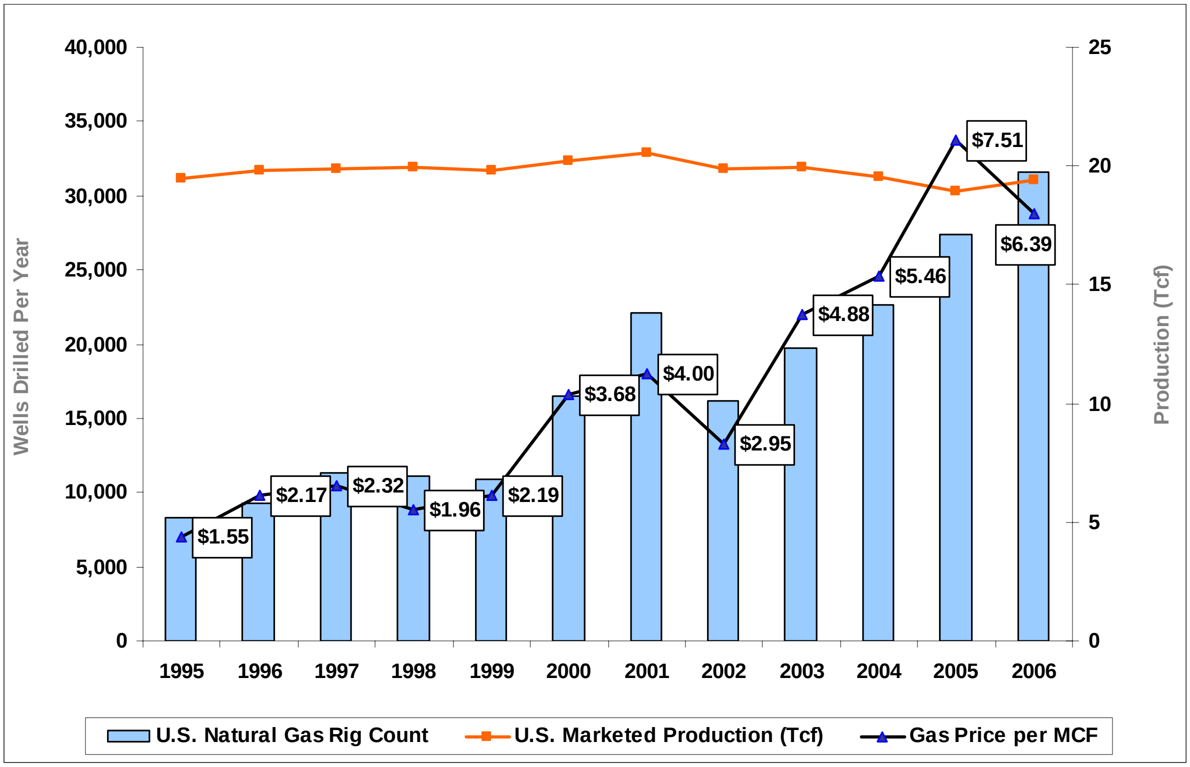


Source: Gas Potential Committee, *Folio of Historical Production Trends and forecast for the United States*, 2004

Since 1995, the price of natural gas (in nominal dollars) has risen, and the number of wells drilled per year rose from about 8,400 to over 31,000 (see **Table 7**). In stark contrast, gross production has remained flat to slightly declining, as observed in **Figure 43**. However, there are some indications that production is beginning to respond to the increased drilling and prices. Estimated production losses from the 2005 hurricanes are approximately 0.5 trillion to 0.75 trillion cubic feet (Tcf). The industry has recovered some of this lost production. Marketable gas production increased slightly over 2005 production by 2.2 percent. The prospects for flat to slightly increasing production during the forecast period are further supported by the dramatic increase in production in the Rocky Mountains (**Appendix B**), the recent significant discovery in the deepwater Gulf of Mexico, and the increase in the production from unconventional plays (for example, Barnett Shale).

However, as shown on **Figure 43**, despite the dramatic increase in the number of wells drilled, the production response has been modest at best. Sustaining the current high level of drilling will be a challenge to the industry.

Figure 43: Production, Price, and Number of Natural Gas Wells Drilled
(Nominal Dollars)



Source: EIA

Table 7: Natural Gas Prices in Nominal and 2006 Dollars

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nominal$	$1.55	$2.17	$2.32	$1.96	$2.19	$3.68	$4.00	$2.95	$4.88	$5.46	$7.51
2006$	$1.95	$2.68	$2.82	$2.35	$2.59	$4.26	$4.52	$3.28	$5.32	$5.80	$7.76

Source: California Energy Commission Staff, 2007

CHAPTER 4: NATURAL GAS INFRASTRUCTURE

Introduction

This chapter discusses current and future natural gas infrastructure. In previous *Natural Gas Market Assessment Reports*, the infrastructure discussion focused on the pipeline network required to transport natural gas supplies from remote basins to the various end-use points of consumption: residential, commercial, industrial, and power generation. However, the potential importation of liquefied natural gas (LNG) requires the expansion of the discussion of the infrastructure portfolio to include both onshore and offshore regasification terminals.

An extensive pipeline network links the state to several supply basins on the North American continent. As a result, the existing interstate pipeline capacity can satisfy the annual average demand. However, during peak demand periods, the interstate delivery capacity may not fulfill all natural gas demand requirements. Natural gas needed to satisfy the demands of all customer classes--residential, commercial, industrial, and power generation--sometimes display wide variation from month to month and from day to day. The state lacks the interstate pipeline capacity needed to satisfy all demand requirements on the coldest days in winter and, on occasions, when flows on an interstate pipeline experience major disruption or restrictions. During periods of peak demand, the state's storage facilities supply additional natural gas. As a result, the availability of natural gas from storage minimizes the frequency and duration of curtailments.

This chapter explores both interstate and intrastate pipeline capacities used to deliver natural gas to end-use customers as well as the infrastructure requirements for the potential importation of LNG. This assessment of the natural gas market examines the annual average needs over the long-term and does not discuss the infrastructure related to the use of natural gas storage, which holds natural gas to meet short-term daily and seasonal needs.

Major Findings

- During the forecast period, all major pipeline systems serving California, except the Kern River pipeline, operate at utilization rates between 60 and 70 percent.
- On the California leg of its pipeline, Kern River's capacity usage first hovers around 80 percent, then exceeds 90 percent in the middle and end of the forecast horizon.
- LNG entering California could displace natural gas from the Southwest. As a result, flows along the El Paso South system lose market share to LNG supplies from Baja, Mexico.

- Two pipelines affecting California, one interstate and one intrastate, could expand. The interstate pipeline, North Baja westbound, now delivers conventional natural gas to its end users in Baja Mexico. However, after Costa Azul begins operation, this pipeline will reverse and deliver regasified LNG at Blythe/Ehrenberg. As a result, North Baja will expand to accommodate the flow of regasified LNG. The intrastate pipeline, Line 300, receives natural gas from the Southwest and the Rocky Mountains, delivering into the Pacific Gas and Electric utility system. The economics of additional LNG becoming available at the California border result in the model expanding PG&E Line 300. This expansion accommodates the increased natural gas demand in the PG&E system.

Interstate Pipeline Capacity

In 2006, a total of about 9,200 MMcf per day of interstate pipeline capacity served the California natural gas market. This capacity accesses four major natural gas supply basins: *Permian, San Juan, Rocky Mountains*, and *Western Canadian Sedimentary.* The interstate pipeline systems, constructed over the last 50 years, connect these basins to California. The description below maps the route of these interstate pipelines, starting at the supply basin and ending at the California border.

Southwest Basins

El Paso North pipeline system, El Paso South pipeline system, Transwestern Pipeline, and Questar's Southern Trails pipeline connect California to natural gas supplies from the southwest basins: Permian and San Juan. These pipelines deliver natural gas to the California market at Topock, Needles, and Blythe/Ehrenberg. The Havasu pipeline, though not engaged in interstate transportation, moves natural from natural gas from El Paso North to El Paso South. Havasu can deliver a maximum of 700 MMcf per day. Also, the 2003 conversion of the All-American pipeline from an oil to natural gas pipeline allowed additional Permian basin natural gas to reach the California market. The conversion increased the capacity of the El Paso southern system by 125 MMcf per day.

Rocky Mountain Basin

California accesses Rocky Mountain natural gas through the Kern River pipeline, which delivers at Kern River Station. From this delivery point, natural gas flows into the PG&E system, into the SoCalGas system, and to various merchant power plants and industrial facilities in the Kern County area. The Kern River Pipeline, which began operation in 1993 with a capacity of 700 MMcf per day, responded to the 2001 energy crisis by adding about 135 MMcf per day. An additional expansion in 2003 added about 900 MMcf per day, raising the total capacity from the Rocky Mountain basin to 1,760 MMcf per day.

Western Canadian Sedimentary Basin

The Western Canadian Sedimentary (Alberta) basin sends its natural gas production to California through two pipeline systems. Natural gas production leaves the basin on the southward portion of the TransCanada pipeline system, which then interconnects with the Gas Transmission Northwest Corporation (GTN) pipeline at Kingsgate, British Columbia, just north of the U.S.-Canadian border. GTN pipeline then intersects with the Williams Northwest Pipeline at Stanfield, Oregon. At this interconnect point, GTN can access additional supplies from either the British Columbia basin or the Rocky Mountain basin. The pipeline then travels south and connects to California at Malin, Oregon, providing natural gas supplies to the PG&E mainline, or backbone, pipeline system.

Summary of Interstate Pipeline Capacity

Table 8 summarizes interstate pipeline capacity between 2002 and 2006. Since the energy crisis of 2001, delivery capacity to California has expanded significantly, climbing to over 9,100 MMcf per day in 2006 from 7,821 MMcf per day in 2002. **Table 8** also lists those pipelines passing through the state that deliver little or no natural gas for consumption. Tuscarora in the north and North Baja in the south both pass through California but deliver natural gas in Nevada and Baja California, respectively. As shown in Table 8, delivery capacity to California increased by about 18 percent between 2002 and 2006, where capacity for those pipelines passing through the state increased by about 15 percent during the same period.

Cost of Natural Gas Transportation

Every pipeline transporting natural gas charges a fee to move the natural gas across the system. In the World Gas Trade Model/ North American Regional Model (WGTM/NARG), the cost of transporting natural gas falls into two category: a fixed or demand charge and a variable or volumetric charge. **Table 9** provides the estimated transportation costs of moving natural gas over selected pipeline systems.

Table 8: Interstate Pipeline Delivery Capacity to California

	MMcf per Day		
Pipelines Delivering Gas to California	**2002**	**2004**	**2006**
Gas Transmission North (TransCanada)	2090	2090	2190
El Paso North (El Paso)	2000	2000	2300
El Paso South (El Paso)	1457	1777	1410
Kern River (Kern River Gas Transmission) (1)	835	1735	1760
Southern Trails (Questar)	80	80	80
Transwestern (CrossCountry Energy/TransCanada)	1185	1185	1210
Transportadora de Gas Natural (TGN) (Sempra Energy) (2)	174	174	180
Total Delivery Capacity (3)	**7821**	**9041**	**9130**
Pipelines Passing Through California (4)			
Tuscarora (Sierra Pacific/TransCanada)	98	185	185
North Baja (TransCanada)	500	500	500
Total Capacity	**598**	**685**	**685**
(1) Upstream demand draws on the interstate capacity, effectively reducing deliveries to California.			
(2) Pipeline will transport liquified natural gas into San Diego after Costa Azul begins oprations.			
(3) California also receives about 850 MMcf per day from in-state production.			
(4) Pipelines passing through California that deliver little or no natural gas for California consumption.			
Pipeline owner in ( ).			

Source: California Energy Commission Staff, 2007

Table 9: Transportation Cost on Selected Pipelines

Transportation Cost, $/Mcf	
	Estimated Cost in 2006 Dollars
Kern River to California	**0.40**
Gas Transmission Northwest (Stanfield to Malin)	**0.51**
Malin to PGE (Redwood)	**0.36**
San Juan to Topock (Southern Trails)	**0.52**
Intrastate (Topock to SoCalGas)	**0.38**

Source: California Energy Commission Staff, 2007

Intrastate Pipeline Capacity

In 2006, California receipt capacity totaled about 7,900 MMcf per day. The state's receipt capacity has changed little since 2001. **Table 10** summarizes SoCalGas Company's 2006 receipt capacity.

Table 10: Receipt Capacity in Southern California

SoCalGas Receipt Capacity, MMcf/D	
	Capacity
El Paso @ Blythe	**1210**
El Paso @ Topock	**540**
North Needles (Transwestern, Questar Southern Trails)	**800**
Hector Road (Mojave)	**50**
Wheeler Ridge (PG&E, Kern/Mojave, CA Production)	**765**
Line 85 (CA Production)	**190**
North Coastal (CA Production)	**120**
Kramer Junction (Kern/Mojave)	**200**
Total Receipt Capacity	**3875**

Source: California Energy Commission Staff, 2007

A similar capacity profile emerges in Northern California. PG&E receives southwest and Rocky Mountain natural gas along the Baja path (Line 300) and Canadian natural gas along the Redwood path (Line 400/401). **Table 11** summarizes PG&E's 2006 receipt capacity.

Table 11: Receipt Capacity in Northern California

PG&E Receipt Capacity, MMcf/D	
	Capacity
Baja Path (Line 300)	1,140
Redwood Path (Line 400/401)	2,021
Total Receipt Capacity	**3,161**

Source: California Energy Commission Staff, 2007

Combined, PG&E and SoCalGas hold almost 90 percent of the state's receipt capacity. A map showing the pipelines in the western United States and Canada appears in **Appendix C.**

Liquefied Natural Gas (LNG)

With conventional exploration and production slowing in the various supply basins feeding the pipeline network, the construction of LNG facilities is diversifying natural gas supply sources in North America. The addition of new supply sources could narrow the range of price changes in the natural gas market.

LNG is now playing a role in satisfying incremental demand requirements in other parts of the United States. At present, five LNG facilities, all located on the East Coast and Gulf Coast, operate in the lower 48 states. Operating capacity of these facilities—Lake Charles in Louisiana, Elba Island in Georgia, Cove Point in Maryland, Everett Marine in Massachusetts, and Gulf Gateway Energy Bridge in the Gulf of Mexico—totals about 5.8 Bcf per day. A proposed expansion of the Cove Point facility could add 0.8 Bcf per day in the near future. Industry observers expect the development of LNG facilities in North America to continue.

On the West Coast, LNG developers have proposed several terminals, including terminals for both onshore and offshore California. Sempra Energy has began construction of its 1.0 LNG regasification facility (Costa Azul) in Baja California, Mexico, with the expectation of flowing “first gas” in 2008 and has indicated possible plans to expand the facility an additional 1.5 Bcf. Staff added this facility to the WGTM/NARG. **Table 12** outlines the capacity profile for the Costa Azul LNG facility.

Table 12: Terminal Capacity for Costa Azul LNG Facility

Costa Azul Terminal Capacity, MMcf/D		
Year	Cumulative Capacity	Approx. Utilization Rate
2008	1000	25%
2009	1150	70%
2015	2500	70%

Source: California Energy Commission Staff, 2007

In addition to the Costa Azul facility, two terminals in the Gulf of Mexico will begin operation in 2008, adding another 3.3 Bcf per day of LNG regasification capacity.

Basic Assumption about LNG Infrastructure

The assessment requires several basic assumptions about the market dynamics of adding LNG facilities on the West Coast. First, the present natural gas flows on the North Baja pipeline will reverse following the construction of the new LNG terminal in Baja California Norte, Mexico, flowing east instead of its present westward flow from the new LNG terminal, ending at Ehrenberg. Second, the TGN pipeline will supply LNG into the San Diego and Otay Mesa market centers. This pipeline would also serve the local Baja California market.

Third, staff assumes that the Costa Azul LNG facility begins operation in 2008. Fourth, staff configured the model’s structure to accommodate the construction of additional terminals in Baja and in Southern California. However, in the reference case, all Southern California and other Baja California terminals will not begin operation during the forecast horizon. In addition, the model’s structure includes links to potential LNG sources for the West Coast such as the Pacific Rim, Africa, Alaska, Australia, and the Middle East.

Cost of Landed LNG

Once LNG reaches a terminal, the process of regasification begins, ending with pipeline quality natural gas. The WGTM represents the cost of this process with two cost components: a fixed charge and a volume-based charge. At a 70 percent usage rate, the estimated cost of regasifying LNG in 2009 is about $0.33 per Mcf. Overall, the landed cost of regasified LNG used in the model varies between $3.75 and $5.75 per Mcf, depending on the origin of the LNG and the market into which it flows.

Infrastructure Forecast Results

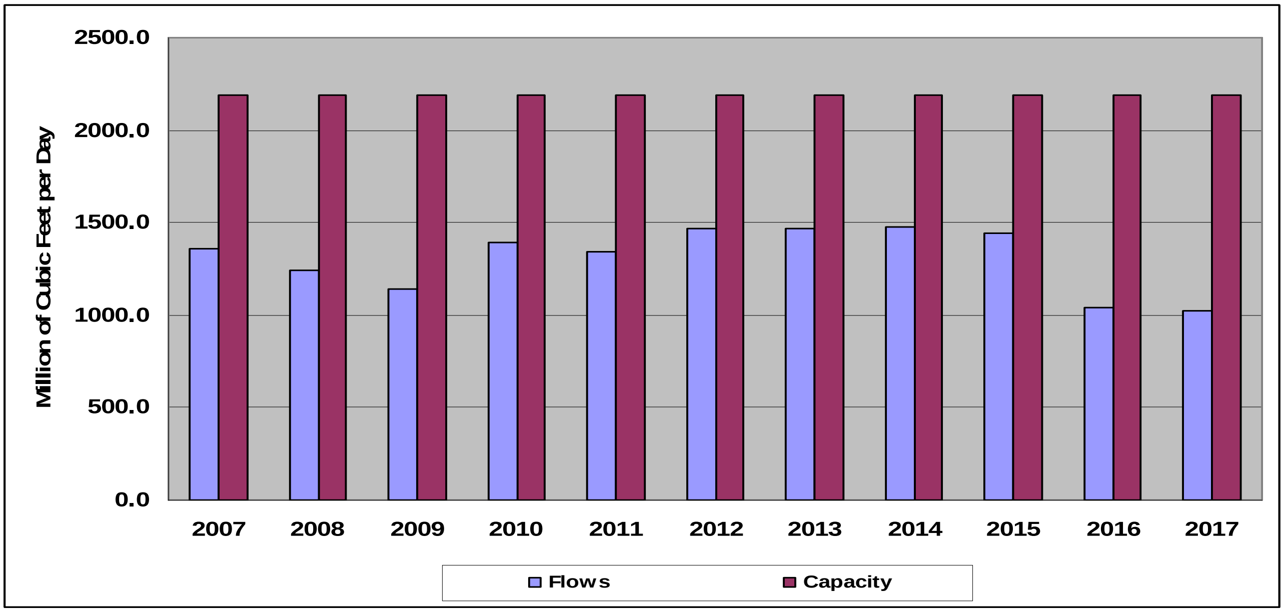
Interstate Infrastructure Portfolio

Figures 44 through **53** present model results relating to natural gas infrastructure.

Figure 44 shows projected natural gas flows and capacity at Malin, Oregon. Natural gas from the Western Canadian Sedimentary Basin reaches Malin through the Gas Transmission Northwest pipeline. Available capacity at Malin is about 2,190 MMcf per day. Natural gas then enters the PG&E system and travels along PG&E's Redwood Path, which can handle flows up to around 2,021 MMcf per day. However, during the forecast horizon, capacity use varies between 60 and 70 percent, and at the end of the forecast horizon, capacity use falls to about 50 percent. Canada's greater demand for its natural gas production and declining supplies from the Western Canadian Sedimentary Basin places downward pressure on capacity utilization of the GTN pipeline system.

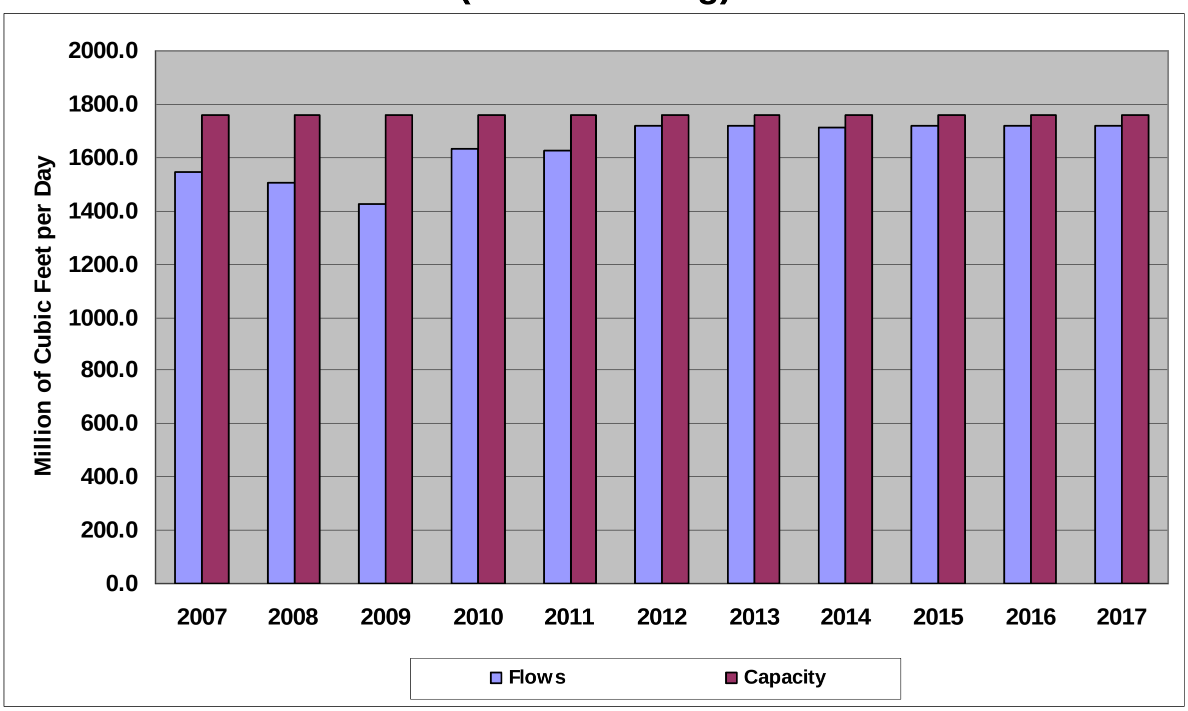
Figure 45 shows natural gas flows and capacity along the Kern River pipeline system (California leg). Natural gas from the Rocky Mountain Basin reaches California through the Kern River pipeline, which, on the California leg, can deliver about 1760 MMcf per day. However, deliveries on this pipeline system satisfy 85 percent of the natural gas demand requirements in southern Nevada, limiting its ability to flow more natural gas into the state. Natural gas from the Rocky Mountains serves the enhanced oil recovery industry and other markets in California. During the forecast horizon, capacity utilization first hovers around 80 percent before climbing and exceeding 90 percent. Rocky Mountains natural gas, which mostly serves the enhanced oil recovery industry and other large end users in California, maintains a competitive edge when compared with other natural gas sources. As a result, Kern River capacity usage factors remain relatively high.

Figure 44: Flows and Capacity at the California Border (Malin)



Source: California Energy Commission Staff, 2007

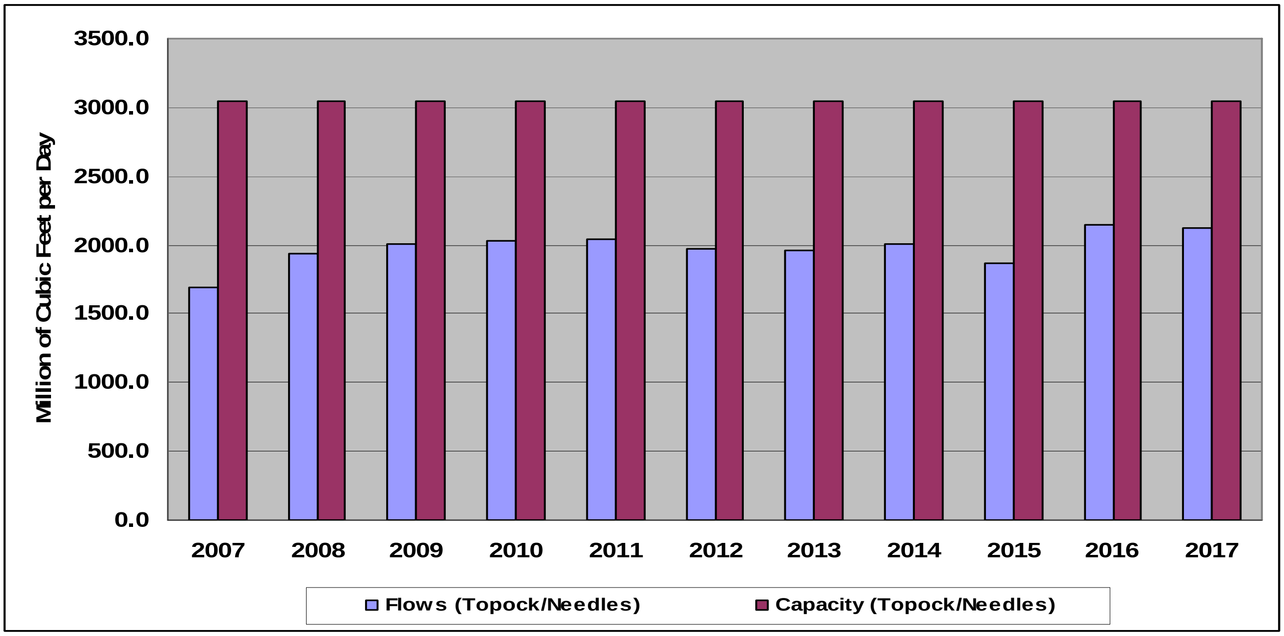
Figure 45: Flows and Capacity at the California Border (Kern River) (California Leg)



Source: California Energy Commission Staff, 2007

Figure 46 shows the natural gas flow and capacity at Topock, California, on the Colorado River. California receives natural gas from the San Juan Basin through three pipeline systems: El Paso North, Transwestern, and Southern Trails. Receipt capacity totals about 3,000 MMcf per day. Throughout the forecast horizon, the combined use of these pipelines averages about 67 percent.

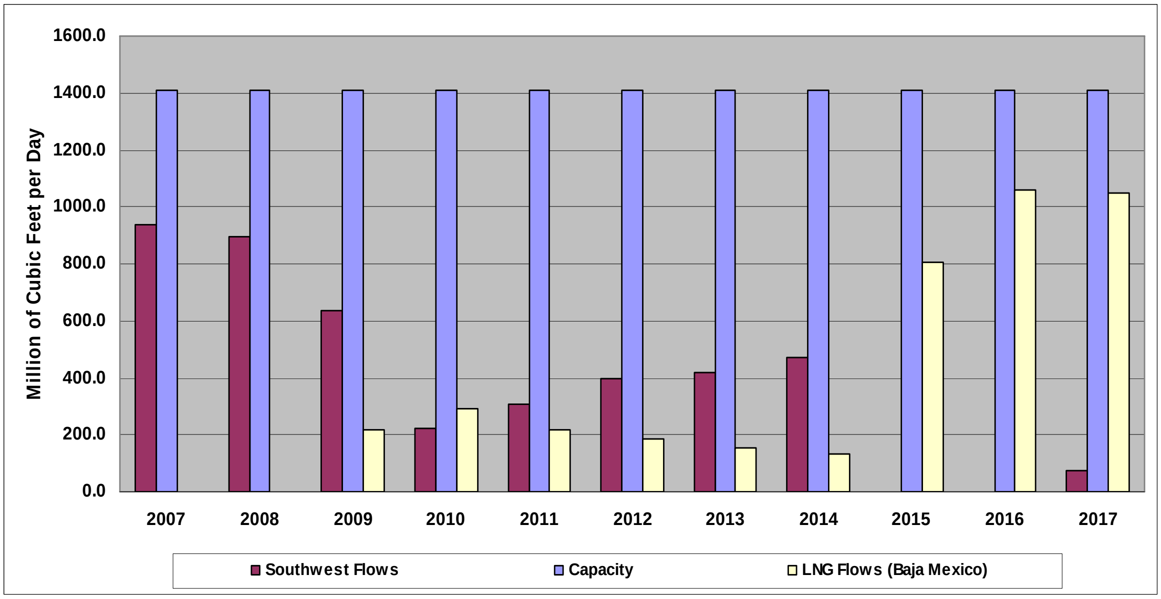
Figure 46: Flows and Capacity at the California Border (Topock)



Source: California Energy Commission Staff, 2007

California receives natural gas from the Permian Basin through the El Paso South pipeline system. This pipeline delivers at Blythe/Ehrenberg. After the Costa Azul LNG terminal begins operation, the North Baja pipeline will also deliver regasified LNG at this market hub. The insertion of LNG into this hub will intensify gas-on-gas competition. Model results project that regasified LNG would displace southwest natural gas and dominate the natural gas flows at Blythe (**Figure 47**). Capacity usage for southwest natural gas declines and hovers around zero by the end of the period. However, LNG flows increase during the same period.

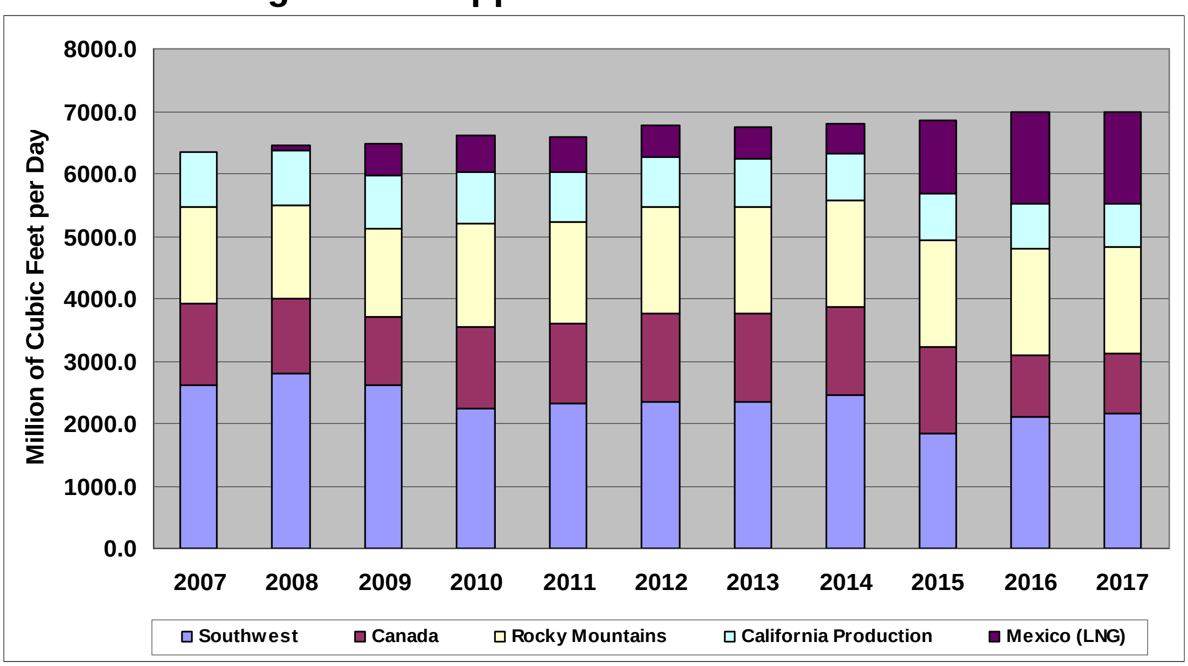
Figure 47: Flows and Capacity at the California Border (Blythe)



Source: California Energy Commission Staff, 2007

Figure 48 shows why the current pipeline systems deliver natural gas to California at capacity factors below 100 percent, and sometimes below 60 percent. As LNG flows from Baja Mexico increase, southwest flows decrease. Southwest flows at Blythe experience the largest reduction. As a result, regasified LNG from Mexico displaces natural gas from the Southwest**.**

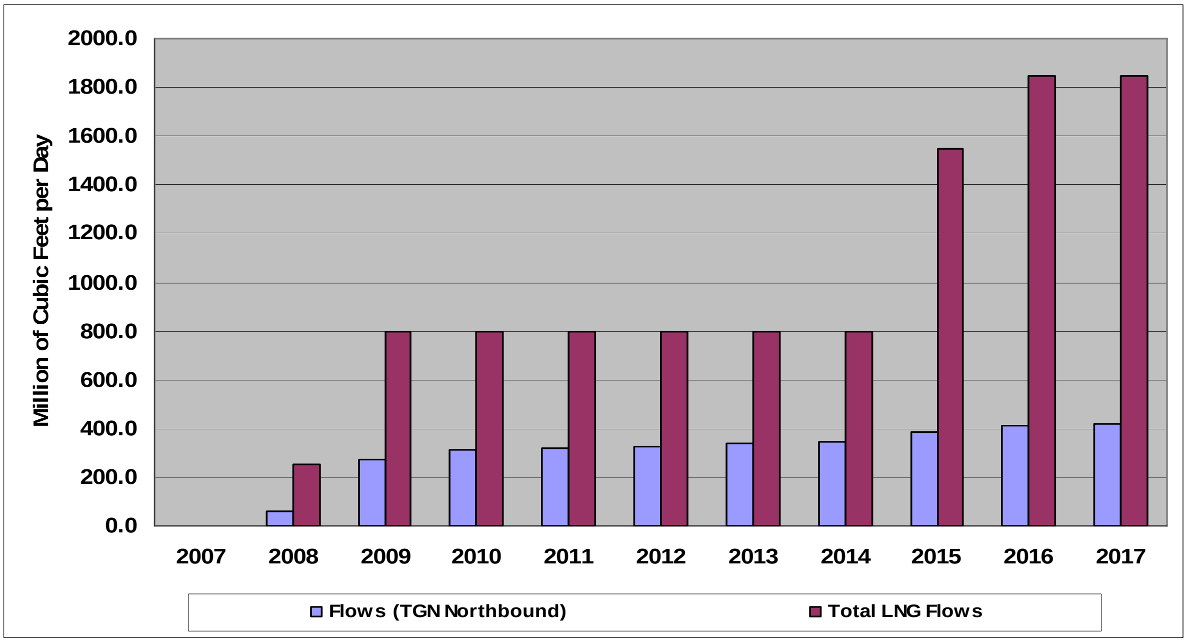
Figure 48: Supplies Available to California



Source: California Energy Commission Staff, 2007

Figure 49 shows LNG flow from the Costa Azul terminal in Baja Mexico. LNG reaches California via two routes: TGN northbound and North Baja eastbound. The analysis assumed that Costa Azul will expand in 2015, increasing flows to Blythe/Ehrenberg. The comparatively lower cost LNG pushes out Southwest natural gas supplies.

Figure 49: LNG Flows from Terminal



Source: California Energy Commission Staff, 2007

During the forecast horizon, interstate capacity expansions occur only on North Baja eastbound. Model results project that this pipeline will expand by about 560 MMcf per day in 2015 (**Table 13**).

Table 13: Capacity Expansion on Pipelines Affecting California

	North Baja Eastbound
2007	0.0
2008	0.0
2009	0.0
2010	0.0
2011	0.0
2012	0.0
2013	0.0
2014	0.0
2015	562.0

Source: California Energy Commission Staff Assessment, 2007

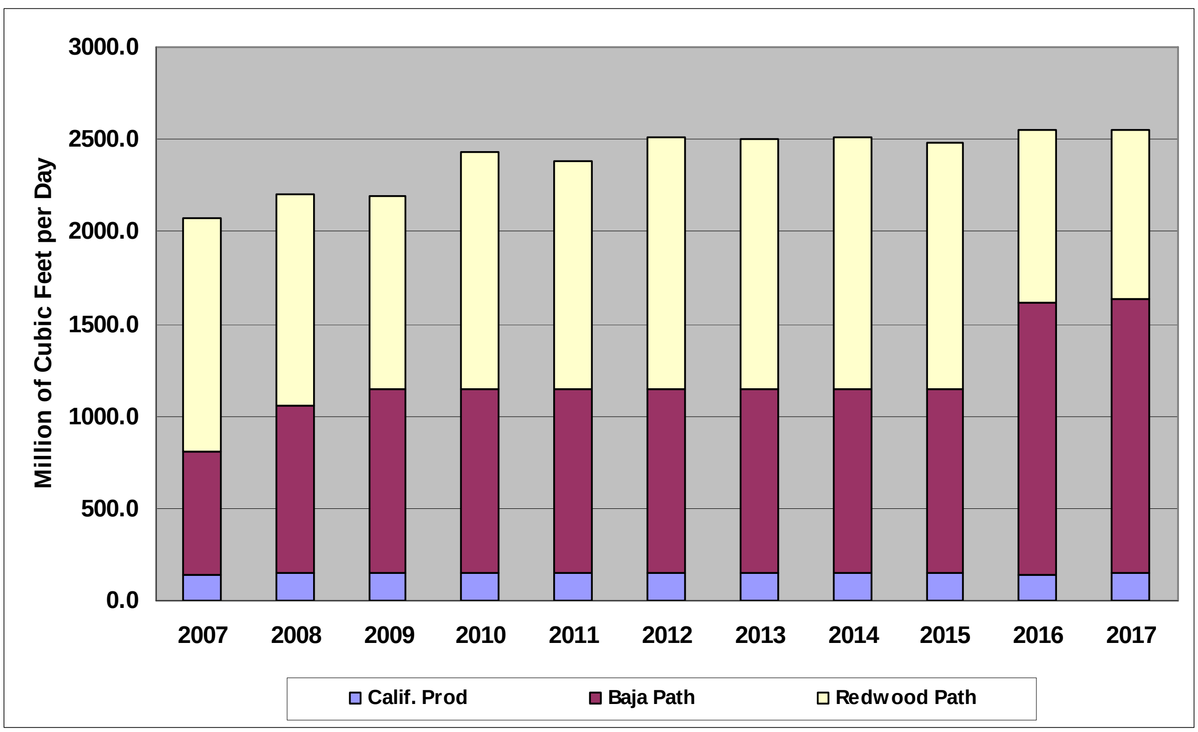
The projected excess capacity on the interstate pipelines serving California is based on average hydro conditions. In the event that a severe drought on the West Coast reduces hydroelectric generation, all or part of that excess capacity would be needed to meet the increased demand by natural gas fired electric generators.

Intrastate Infrastructure Portfolio

PG&E receives natural gas from three main sources: the Redwood path (Line 400/401), the Baja path (Line 300), and instate production.

Accessing natural gas from the Western Canadian Sedimentary basin via GTN, the Redwood path, with firm capacity rights of over 2,000 MMcf per day, delivers into the PG&E system from the north. The Baja path, with firm capacity rights of more than 1,100 MMcf per day, accesses natural gas supplies from both the Rocky Mountains and the Southwest. Due to additional LNG flows assumed from the south, the flows on the Baja path exceed its current capacity, indicating economic pressure to expand by about 480 MMcf per day in 2016. **Figure 50** illustrates the sources of flows into PG&E.

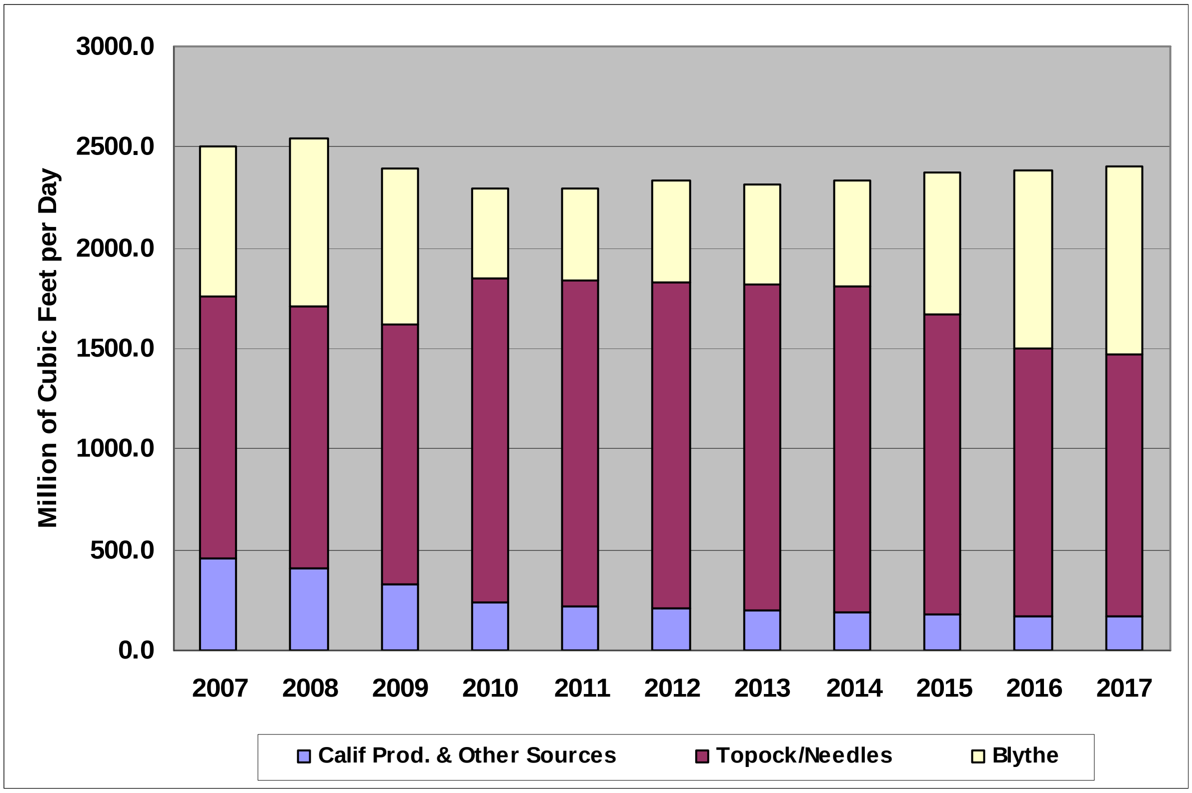
Figure 50: Flows into Pacific Gas and Electric



Source: California Energy Commission Staff, 2007

SoCalGas holds a total of 2,750 MMcf per day of firm capacity rights at Blythe and Topock/Needles and receives most of its demand requirements from these delivery points. **Figure 51** shows natural gas flows into the SoCalGas utility system. The forecast projects that the SoCalGas demand requirement will decrease in the early portion of the forecast horizon, reaching its low point around 2010. **Figure 52** reveals the reason for this observation.

Figure 51: Flows into SoCalGas

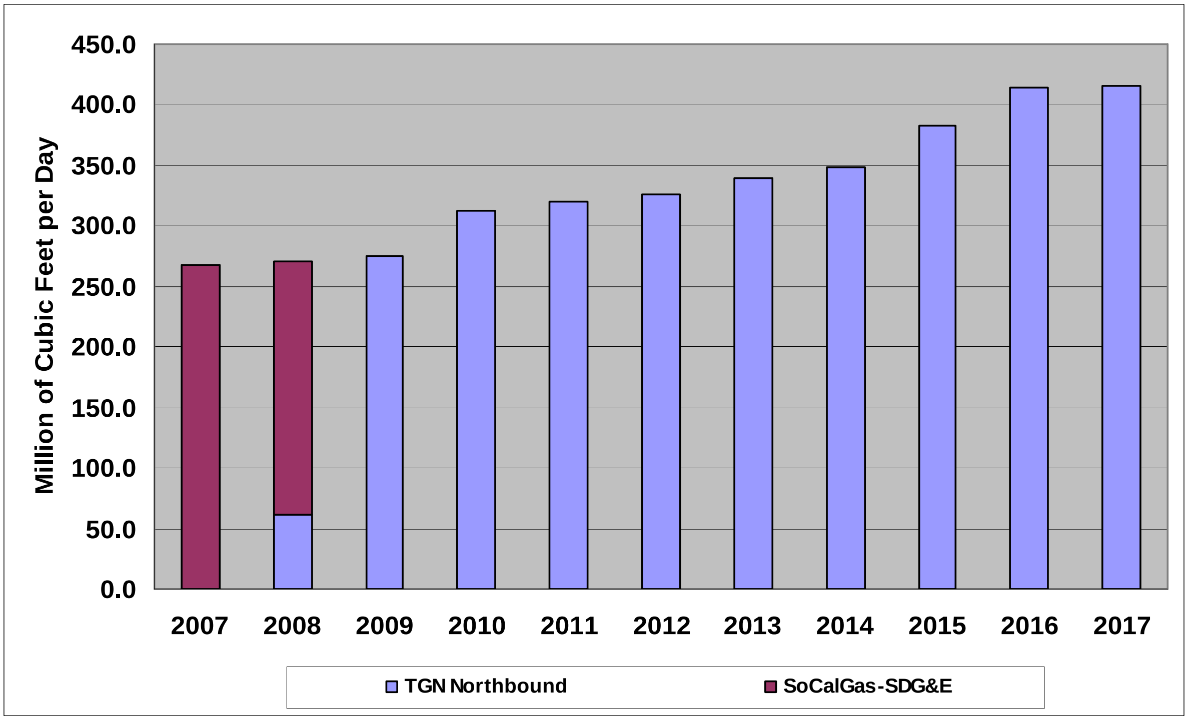


Source: California Energy Commission Staff, 2007

SoCalGas now serves the San Diego market. However, after Costa Azul begins operation, TGN flows into San Diego increase, pushing out natural gas flows from the north. As a result, the SoCalGas natural gas requirement decreases in the early part of the forecast horizon. Figure 52 shows the displacement of flows from the north by LNG flows from Baja Mexico along TGN northbound.

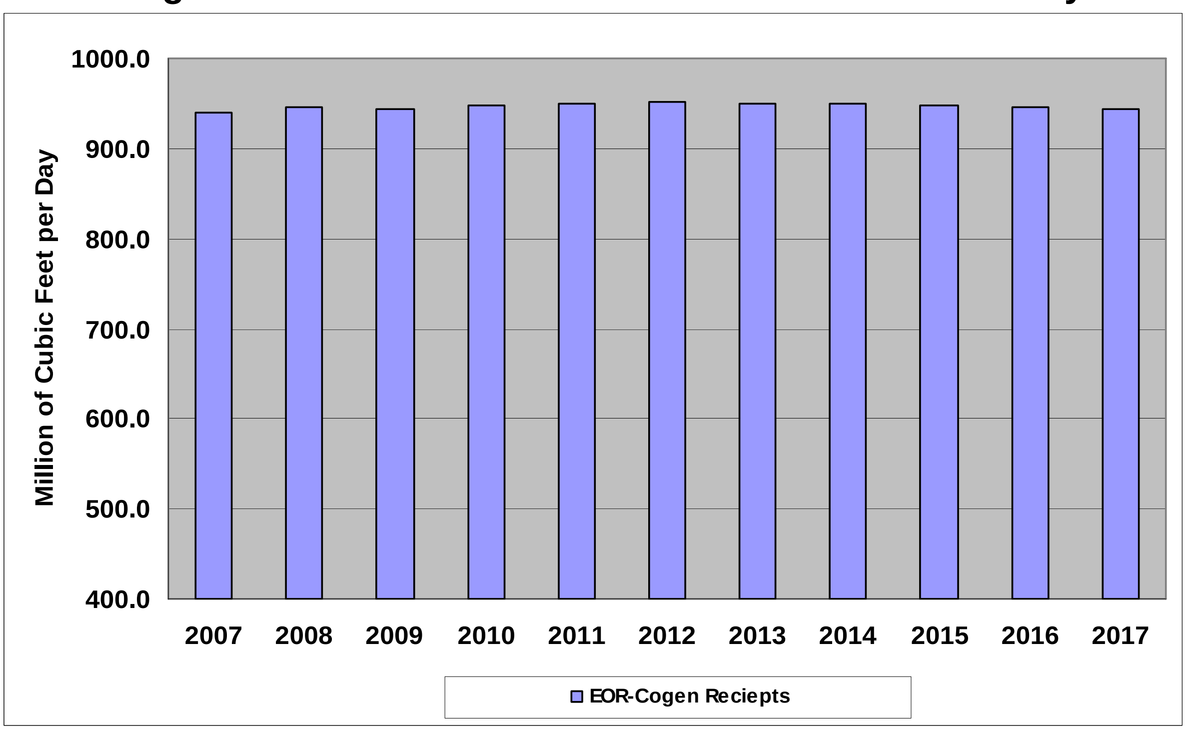
Figure 53 illustrates the demand requirement of the enhanced oil recovery markets. At this time, both Kern-Mojave and SoCalGas serve this market. The forecast projects that direct deliveries by Kern-Mojave into the TEOR market will displace deliveries from SoCalGas.

Figure 52: Flows into San Diego Gas and Electric



Source: California Energy Commission Staff, 2007

Figure 53: Flows into Thermal Enhanced Oil Recovery



Source: California Energy Commission Staff, 2007

CHAPTER 5: NATURAL GAS PRICES

California is part of a natural gas market that extends across North America and includes the United States, Canada, and Northern Mexico. As discussed in Chapter 4, the pipelines in North America are like a spider web that connects all the supply areas with the demand centers. Basically there is one market, but because of regional differences, there are also regional price divergences. The general price trends are the same, but because of variations in supply availability, pipeline capacities and levels of demand, the prices vary from one region to another.

This chapter focuses on natural gas prices in the West, with some attention on other regions. The chapter identifies and discusses detected shifts in the natural gas market and evaluates the basis spread[4] during the forecast horizon. The basis spread evaluation compares the prices at selected hubs — Chicago City Gate, New York, Opal, AECO, Malin, and the Southern California border — with prices at Henry Hub, located in Louisiana. Price projections are in 2006 dollars unless otherwise noted.

Major Findings

- The model projects relatively stable prices early in the forecast period, rising thereafter to approximately to $7 per Mcf by 2017.
- More available supply options could increase natural gas-on-gas competition over the next 10 years.
- Basis spreads between Henry Hub (Louisiana) and other hubs increase during the forecast period. This implies that the Henry Hub price is not rising in lockstep with other North American hubs and remains low because most of expected imported LNG coming into the Gulf Coast is close to Henry Hub.
- Some of the basis spreads that traditionally were negative become positive. The discount that California has enjoyed relative to Henry Hub becomes a premium.

Price Forecast Results

Figures 54 through 56 present staff's expected natural gas price forecast.

Figure 54 shows the forecasted prices for selected hubs. There is a relatively constant basis differential throughout the forecast horizon. However, the slight tightening of spreads from about $1.00 in 2008 to $0.60 at the end of the study horizon means that the demand centers have more options to select their needed supplies. The initial drop in prices reflects an assumed increase of LNG flows into the United States. Appendix M provides prices at important hubs in North America.

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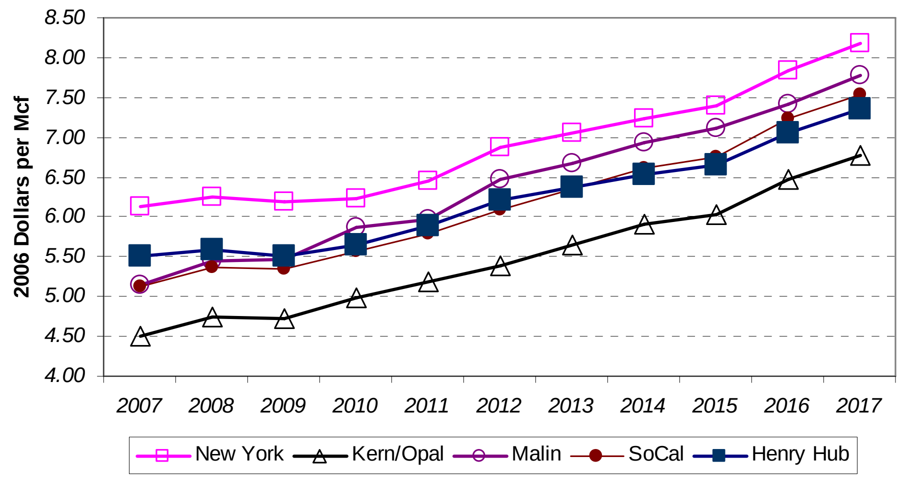
4 Basis spreads are the difference between prices at two different locations. The comparison is typically made between prices at a given location versus Henry Hub.

Figure 54: Average Annual Hub Prices



Source: California Energy Commission

Over the next 10 years, more available supply options will increase natural gas-on-gas competition. This begins with building new pipeline capacity to connect supply regions with demand centers. With the addition of pipelines like the Rockies Express, landlocked supply regions are opened up to new markets. LNG facilities add to the available supply mix. Appendix N provides a more detailed price description in tabular form.

Historical and forecasted price spreads for Henry Hub with other selected hubs are shown in **Table 14**. The historical basis spreads are based on annual average hub prices for the indicated locations, as published by *Natural Gas Week,* and are expressed in 2006 dollars.[5] While seasonal or monthly spreads would be more informative, the Energy Commission's current modeling provides only for annual prices.

All the basis spreads between Henry Hub and other hubs are increasing. This implies that the Henry Hub price is not rising as fast as the other hubs in the United States and Canada. Influencing this is the landing of nearly all new LNG supply in the Gulf Coast, near Louisiana, where the Henry Hub is located. This new supply tends to dampen price increases in the area. The regional market phenomenon of transport cost and supply mix lead to faster hub price rises elsewhere than at Henry Hub. Appendix O provides a table of all California border prices.

5 California Energy Commission's May 30, 2005, deflator series was used to convert historical prices to constant 2006 dollars.

Table 14: Annual Average Natural Gas Basis Differentials (Dollars per Mcf)

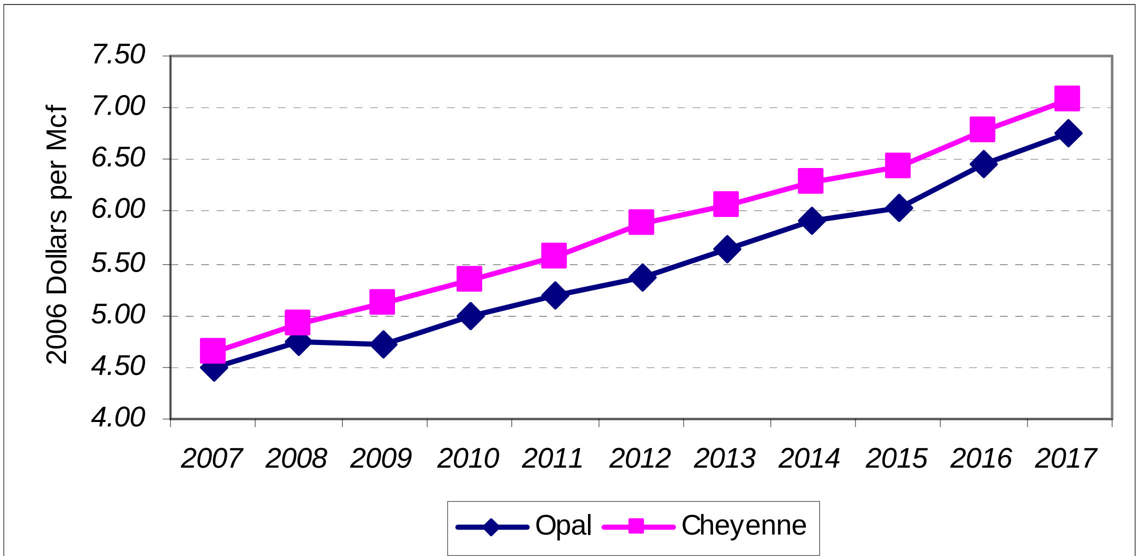
	Chicago	New York	Kern/Opal	AECO	Malin	SoCal
Historical						
2003	0.10	0.61	(1.13)	(0.78)	(0.68)	(0.63)
2004	(0.12)	0.73	(0.82)	(0.89)	(0.56)	(0.43)
2005	0.12	1.42	(1.30)	(0.81)	(0.82)	(0.31)
2006	0.32	0.84	(1.47)	(0.10)	(0.38)	(0.35)
Forecasted						
2007	(0.07)	0.63	(1.01)	(0.99)	(0.35)	(0.39)
2008	0.06	0.67	(0.84)	(0.79)	(0.13)	(0.21)
2009	0.11	0.67	(0.80)	(0.68)	(0.05)	(0.17)
2010	0.17	0.59	(0.67)	(0.57)	0.22	(0.09)
2011	0.17	0.57	(0.70)	(0.67)	0.08	(0.09)
2012	0.17	0.66	(0.84)	(0.58)	0.25	(0.12)
2013	0.23	0.69	(0.72)	(0.54)	0.31	(0.02)
2014	0.27	0.71	(0.62)	(0.51)	0.39	0.08
2015	0.31	0.74	(0.63)	(0.46)	0.46	0.10
2016	0.32	0.78	(0.59)	(0.47)	0.35	0.18
2017	0.35	0.83	(0.58)	(0.45)	0.42	0.18

Note: Indicated Hubs are compared with Henry Hub
( ) indicates negative number
Source: California Energy Commission and Natural Gas Week

The forecasted basis differentials compare very favorably with actual recorded spreads. Except for Malin and at the Southern California border, positive prices remain positive, and negative prices remain negative. For California, this means that between 2010 and 2013 the state would no longer be in the favorable position of having its border prices lower than the Henry Hub price.

There was some concern that when the Rocky Mountain Express Pipeline goes into operation in 2009, a shift might occur in the basis spread at Opal. A shift does occur but not as expected. Western Rocky Mountain production marketability seems to be enhanced after pipelines, such as the Rocky Mountain Express, are built to export eastern Rocky Mountain production to eastern markets. Lower-priced Opal drops an additional $0.30 to $0.40 per Mcf below the Cheyenne hub after the pipeline expansions (**Figure 55**). This appears to be "good news" for California; however, even Sempra Executive Vice President Mark Snell suggested at a recent conference (Lehman Brothers CEO Energy/Power Conference) that the relative mix of demand versus supply and LNG flows into Costa Azul may affect how much Rockies gas continues to come to California. Less Rockies gas left for California increases basis risk.

Figure 55: Comparison of Opal and Cheyenne Hub Prices



Source: California Energy Commission

Natural gas prices for electricity generation follow general price trends with some regional differences. **Figure 56** shows electric generation natural gas prices for 5 of the 32 fuel group price forecasts.[6] Both Kern River and the Arizona South fuel groups receive natural gas directly off interstate pipelines. The prices for these two fuel groups are lower than the prices for California utility power plants. In the long term, Southern California prices are lower than in the north. Because of the access to natural gas from LNG in the south, the southern utility commodity prices are lower than PG&E's. SoCal Gas and SDG&E's electric generation natural gas prices move in lockstep during the most of the forecasted period. Appendix P, Tables P-1 through P-4, provides a description of the method used to develop the end-use price forecast and the resulting price profile.

Historical wellhead price forecasts of the California Energy Commission and the EIA are shown in **Appendix D** – Historical Price Forecasts.

The price of regasified LNG delivered into the natural gas system is not necessarily the cost of delivering and regasifying it. If LNG were a price setter, then the price would equal the cost. But LNG is a price taker, so its price will be more reflective of current market conditions. The result is that the overall price for a supply mixture of LNG and U.S.-produced natural gas would be lower than if the LNG was not in the mix.

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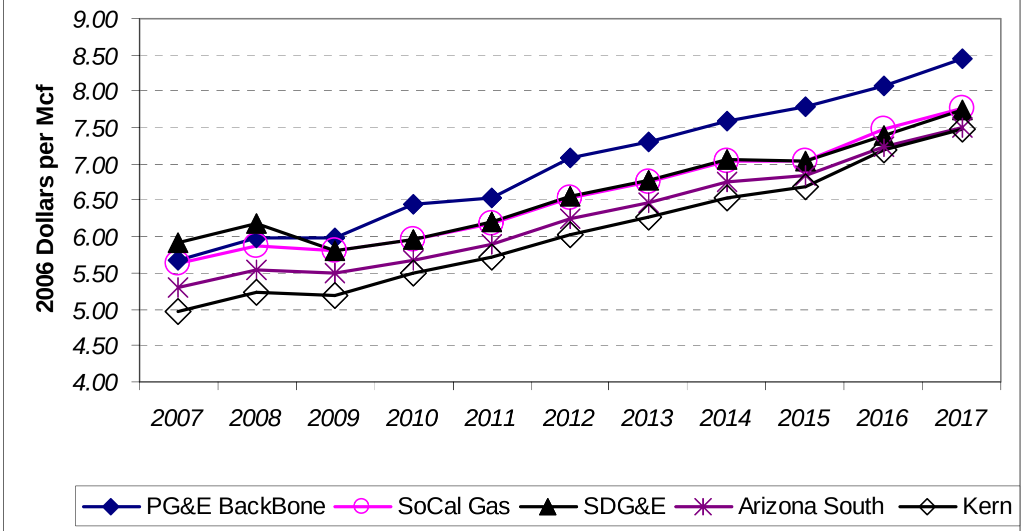
6 For electricity resource analysis, the Energy Commission has assigned all existing and new power plants to one of 32 "fuel groups." These are based on location and whether they receive service directly from an interstate pipeline or from a utility.

Figure 56: Forecasted Electric Generation Natural Gas Prices



Source: California Energy Commission

To illustrate what may happen, presume that Costa Azul regasified LNG cost is $5.00 per Mcf. It is being introduced into the general pipeline system at Ehrenberg, Arizona, where it may flow to many locations. It is directly competing with natural gas produced in the San Juan Basin. Before the plant was built, the San Juan price was $7.00 per Mcf. Appendix Q provides pricing data on all LNG terminals in North America.

After the LNG plant is operational, its price will inch upward from its cost of $5.00 to meet the San Juan $7.00 price. In the meantime, to minimize its loss of market share to the lower-priced LNG, the San Juan price drops incrementally until supply and demand at Ehrenberg are at equilibrium. The resulting price could be in the area of $6.50 per Mcf, a drop of $0.50 per Mcf in the price consumers will pay for their natural gas supply.

CHAPTER 6: ALTERNATIVE CASES

The Energy Commission retained consultant R. W. Beck, Inc., to provide comments on the natural gas assessment's reference case assumptions, develop alternative assumptions designed to help evaluate different possible outcomes, and assist staff in reviewing its model outputs as part of its preparation for the *Revised/Final Natural Gas Market Assessment* report. It should be noted that R. W. Beck did not develop the reference case assumptions and may produce forecasts that are different from those in the reference case. This section summarizes R. W. Beck's comments and presents the alternatives the company suggests that the Energy Commission and users of the natural gas price forecast and modeling output evaluate, albeit generally qualitatively, as they consider the analysis and its results.

Major Findings

Among these findings are two approaches for recognizing the uncertainty in forecasting natural gas demand to develop low and high case demand assumptions: one quantitative that uses the distribution of recorded demand growth to create a range around the expected demand case and one qualitative that identifies the "bottoms-up" factors that could create higher-versus-lower demand. The quantitative analysis demonstrates that a reasonable high case could be 1.5 Tcf higher than staff's reference case.

The consultant additionally developed a heuristic tool to create a snapshot of natural gas supply that can ultimately be used to assess the supply/demand balance. The heuristic does not replace staff's use of the WGTM/NARG model but rather helps staff evaluate and put the model results into perspective. The heuristic allows one to summarize the components of natural gas supply and quickly see how small changes in production per well or wells drilled, or supply from Canada, change the U.S. supply/demand balance.

The high supply case assumes that production per well remains constant and that producers drill more wells. It demonstrates a slight excess of supply relative to demand in nearly all years of the forecast.

The low supply case assumes production per well falls off, that the number of wells drilled is capped at the 2006 approximate number of 30,000, and that Canadian supply falls off somewhat more quickly. In this case, the imbalance (potentially met with LNG) grows to nearly 10 Tcf by 2017.

R. W. Beck also evaluated the relationship between oil and natural gas prices. This is a perennial debate. Many assume that natural gas prices should trade at a fixed ratio to oil prices. The analysis demonstrates that the relationship between oil and natural gas prices is much more complex and varied.

Forecast Methodology

As its principal tool to assess natural gas market fundamentals, the Energy Commission staff uses the World Gas Trade Model, which includes the NARG model as its North American component. This model uses a fundamental approach in which market-clearing prices and quantities are determined at the point of supply-demand equilibrium. The model uses as its input a number of variables generally categorized in terms of regional supply curves for North American natural gas: costs of existing and prospective field processing and gathering; costs of existing and prospective long haul and backbone pipelines; demand and the price, income, and weather sensitivity thereof; LNG liquefaction, shipping, and regasification worldwide; and full arbitrage of tankers and natural gas through the continent and around the world. Fundamental models have proven very useful and quite accurate for simulating production, product flows, and consumption and to superimpose and consider non-economic uncertainties such as the impact of transportation limitations and costs on locational price differentials.

However, there have been concerns regarding prices projected by NARG and similar models as they tend to deviate from actual market prices. The following observations briefly explain the issue.

Fundamental models like WGTM/NARG are designed to estimate equilibrium — that is, the point at which supply balances with demand. The marginal cost of supply at the equilibrium point becomes the forecast price of natural gas. Therefore, the price such models project is a proxy of the long-term equilibrium marginal cost, which is the development and operation cost of the marginal unit of natural gas produced.

Although economists generally agree that the natural gas market is highly competitive and liquid, there is tremendous uncertainty about the appropriate values to assign most of the key fundamental and structural variables. The deviations of fundamental model-based projected prices from observed market prices are the result of the difficulties (or the lack) of modeling market uncertainties. Some of the main reasons for the price projection deviations include the difficulty (or the omission) of modeling abrupt and sometimes severe changes in weather conditions, pipelines outages and congestion, production and storage capacity and availability limitations, and the asymmetry of information.

In addition to supply and demand uncertainties, other variables that contribute to the uncertainty of market price movements may include trading behavior, erratic weather events, regulatory and policy shifts, and major outages to supply/infrastructure facilities. Some of these variables can be highly volatile and can sometimes lead to extreme price spikes, which are often short-term and would never be reflected in a model output that yields annual average prices.

In recent IEPR cycles, the NARG model has been used at the Energy Commission deterministically to project annual prices in a base, or reference case. Sensitivity analyses, which test a limited number of variations of selected variables, are not enough to capture the wide range of possible outcomes.

R. W. Beck prefers a stochastic forecasting approach, which explicitly recognizes uncertainty as best able to capture uncertainties associated with key variables, which in turn create a tractable probability density function of future market prices. Such a model is unfortunately not readily available. NARG, however, is used by many subscribers to perform probabilistic analysis and, if it were used in that fashion by the Energy Commission, could theoretically provide a more complete analysis of uncertain variables to the Energy Commission.

Model outputs are also often criticized for being lower than New York Mercantile Exchange (NYMEX) prices. Forward natural gas contracts have traded consistently in the last few years at a premium relative to spot prices. Over the 12 months (January to December) of 2006, NYMEX Henry Hub (HH) monthly forward prices consistently traded at a premium when compared to the actual contemporaneous spot prices of the same 12 months.

Forward contracts account for future market risk and future supply-demand uncertainty, but spot prices do not; accordingly, forward prices are not good predictors of spot prices. Comparisons of predicted spot prices to NYMEX thus need to recognize the expected and appropriate difference between the two. While forward prices can be used to benchmark the short-term direction of expected spot market price movement, there is no reason to “disbelieve” a long-term forecast merely because the front portion of the forecast differs from NYMEX.

It should be noted that R. W. Beck has not “validated” staff’s forecast, per se. Rather, R. W. Beck has worked with staff in analyzing the outputs and benchmarked them to other available forecasts, including both EIA’s most recent *Annual Energy Outlook* and the forecast produced by Global Energy Decisions for the Energy Commission’s Electricity Scenarios project. As will be later seen, the benchmark comparison shows staff’s reference case to be lower than those forecasts in the early years. Staff’s forecast then rises, roughly matching Global and EIA during the middle of the period and becoming higher than the others by approximately $1 per MMBtu by 2017.

There are also a number of data elements or model elements that deserve further exploration. Staff tends to exclude field use and losses from natural gas demand. This makes comparisons to total supply difficult and sometimes confusing. The model may also have assumed that all resources in the Rocky Mountains are available with no land access restrictions, which may lead to overstating Rocky Mountain production. It is also not well understood whether the model’s insensitivity to higher oil prices recognizes the potential second-order effects of higher oil prices on countries exporting LNG, nor has staff had the opportunity to thoroughly understand in what countries’ higher oil prices might lead to substitution away from oil to natural gas. Last, the preliminary reference case projected importation of large quantities of LNG using assumptions provided by the WGTM/NARG vendor. While staff has constrained this quantity in the revised/final case, staff has not developed its own detailed review and understanding of the upstream economics of LNG that can drive the import quantities.

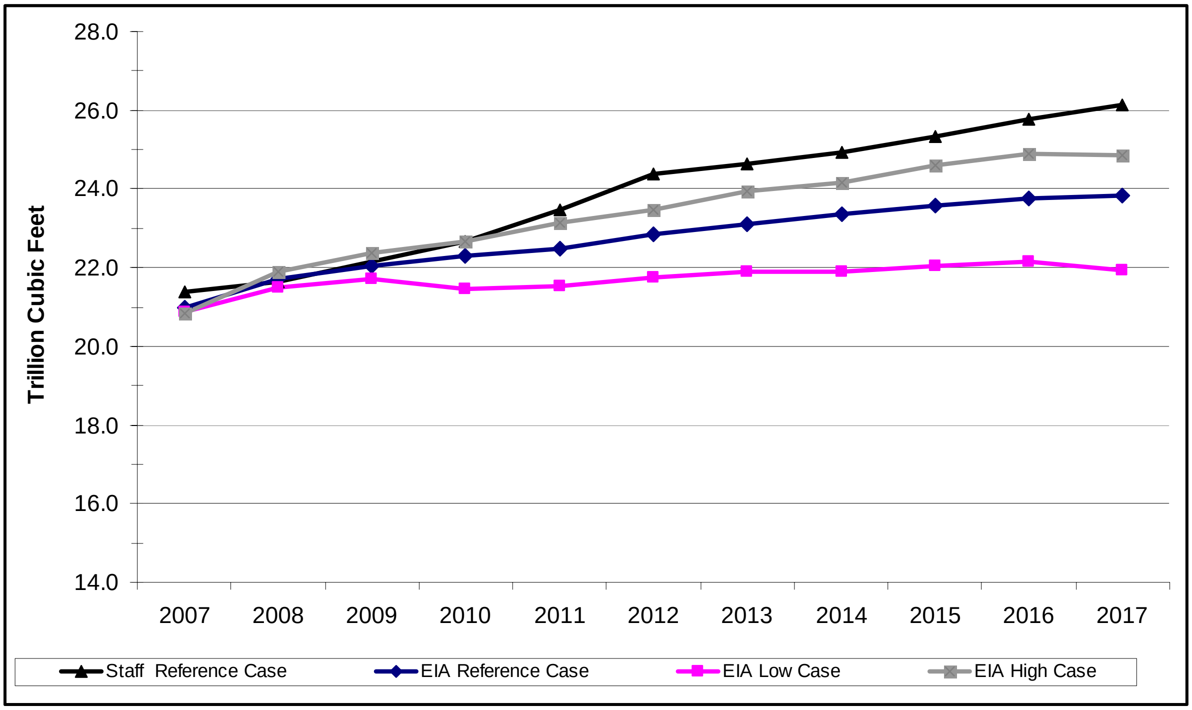
In all, the *Final Natural Gas Market Assessment* takes a step toward an analysis that can capture more of the intrinsic uncertainty surrounding key variables by combining the deterministic NARG modeling effort with a greater focus on trying to highlight and understand the uncertainties that could cause reality to turn out differently than reflected in staff's NARG reference case.

Demand

R. W. Beck offers two approaches to help the Energy Commission staff consider the range of potential variation in natural gas demand around staff's reference case. The first uses the variation in historical demand growth to create a statistical range of potential demand. The second lists the factors one might evaluate in a "bottoms-up" approach or that could be incorporated into further scenario or uncertainty analyses. R. W. Beck also "benchmarks" staff's NARG demand forecast against EIA to illustrate the difference in range of opinion about natural gas demand. The end result is that it appears reasonable to expect that actual demand could deviate above or below forecast demand by as much as 1.5 to 2.0 Tcf per year — a wide range.

Figure 57 compares the end-use natural gas demand forecast from staff's NARG reference case to the demand cases from EIA's *Annual Energy Outlook*. The EIA demand is adjusted to remove pipeline, field, and fuel use to properly compare it with staff's forecast. Projected demand from the NARG case is very similar to both EIA's "high case" and its "reference case" in the first half of the forecast period, then rises to become approximately 0.5 Tcf higher than the high case and 2.0 Tcf higher than the reference case in the second half of the forecast period. Generally, EIA's reference case increases at 1.28 percent per year; staff's NARG reference case demand reflects an annual average growth rate of 2.1 percent. One reason for this difference is likely EIA's inclusion of more coal-fired generation in the WECC than in staff's NARG forecast, which instead reflects the projected electricity generation mix and dispatch results from the Energy Commission's Electricity Analysis Office. Another difference may be associated with staff's use of elasticities that allow NARG to adjust some demand in response to price changes.

Figure 57: Comparison of U.S. Natural Gas Demand Forecasts

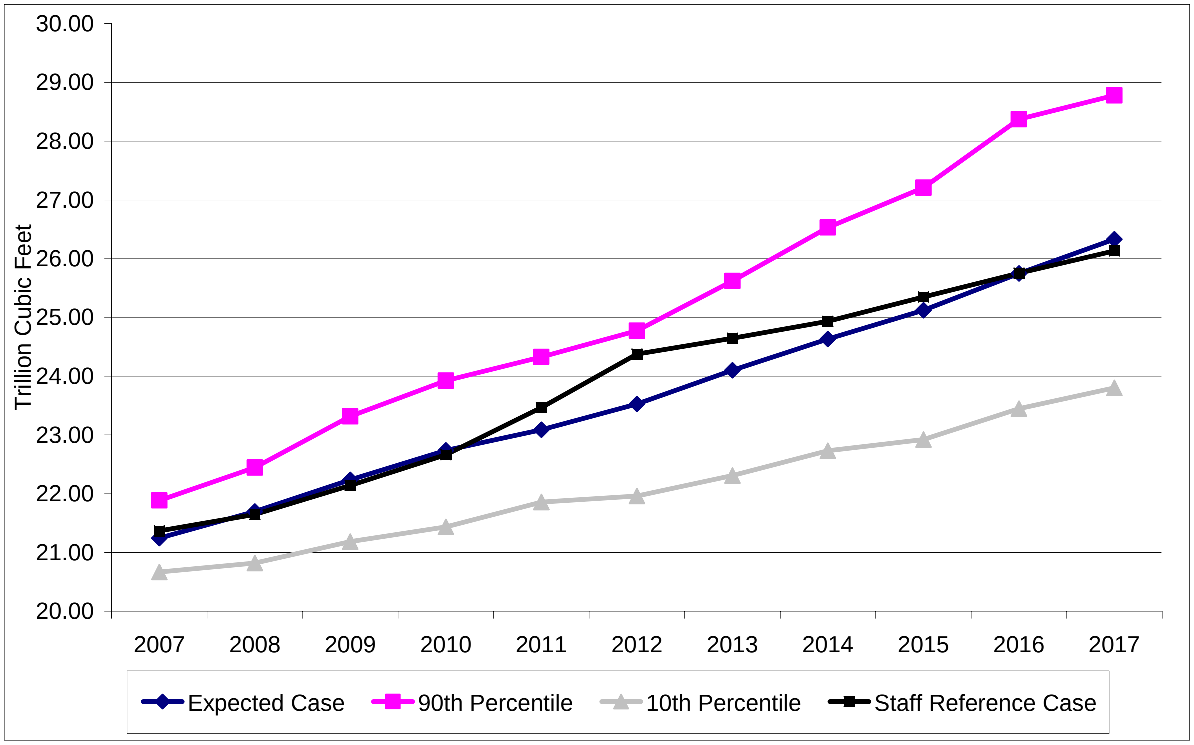


Source: R. W. Beck, 2007

R. W. Beck used two well-recognized approaches to investigate alternative future demand growth possibilities. The first was to analyze the historical volatility of demand growth for each of the major consuming sectors. The assumptions were that the random and diverse impacts of changes in economic, policy, and market variables are typically imprinted in the statistical distribution of the historical data. Assuming that the statistical distribution of each sector's historical demand growth can be represented by a normal distribution, the estimated historical standard deviation (volatility) and mean (average) of these distributions give a proxy picture to the volatility of future growth. This approach is useful because it allows analysts to focus not on quantifying impacts from specific changes in assumptions, but rather to use the historical volatility of demand growth to capture at once a number of different potential outcomes.

After estimating the mean and standard deviation of demand growth for each demand sector, a Monte Carlo simulation approach with 100 random draws was used to estimate the expected value (calculated as the average of the result of the 100 draws) of the rate of growth in demand as well as the 10th percentile and the 90th percentile of future demand growth rates. The 10th and 90th percentiles present an 80 percent confidence level of the range around the expected average of the rate of growth in demand. Applying the expected growth rate to staff's NARG reference case demand yields the "expected case" in **Figure 58**. It varies from the reference case due to the random draws; likewise, the 90th and 10th percentile cases show ups and downs rather than straight-line constants due to the randomness introduced.

Figure 58: U.S. Demand – Alternative Case Forecasts



Source: R. W. Beck, 2007

The second approach was to qualitatively build the projected high and low demand growth cases assuming the most divergent assumptions about economic, policy, and market fundamental variables. **Table 15** identifies a set of key variables and alternative values those variables could take on to create high and low cases. A complete "bottoms-up" analysis of these variables is beyond what is achievable during the short duration of R. W. Beck's assignment. Note however, that this table excludes variables traditionally used to forecast natural gas demand: appliance saturation, housing stock, and population growth. The major uncertainties affecting natural gas demand, rather, are associated with natural gas burned to generate electricity. To the extent that several of these variables are "national" in scope and thus drive aggregate natural gas prices, R. W. Beck encourages staff to look beyond California or the WECC to develop a detailed view of national electric resource mix choices,

Table 15: Variables Creating Demand Forecast Alternative Cases

Drivers	High Natural Gas Demand Growth Case	Low Natural Gas Demand Growth Case	Scope
Efficiency Policy	Slow enactment of legislation/implementation	Aggressive enactment and implementation of policies	National
Conservation Policy	Slow enactment of legislation/implementation	Aggressive enactment and implementation of policies	National
Carbon-reduction Legislation	Aggressive enactment and implementation of policies	Slow enactment of legislation/implementation	National
Coal Generation	No or little capacity additions	50% share of new capacity additions	WECC
Nuclear	Business as usual	Progress in licensing proposed plants	National
Renewable	Slow enactment of legislation/implementation	Aggressive enactment and implementation of policies	National
Economic Growth	High growth case	Slow growth case	National
Hydro Condition	Dry hydro condition	Wet hydro condition	WECC California
Electric Transmission	Critical regional paths are congested	Major transmission capacity expansions into California	California

Source: R. W. Beck, 2007

Based on the statistical analysis reported above, 1.5 to 2.0 Tcf above and below the expected total demand should represent a reasonable range for high and low demand cases.

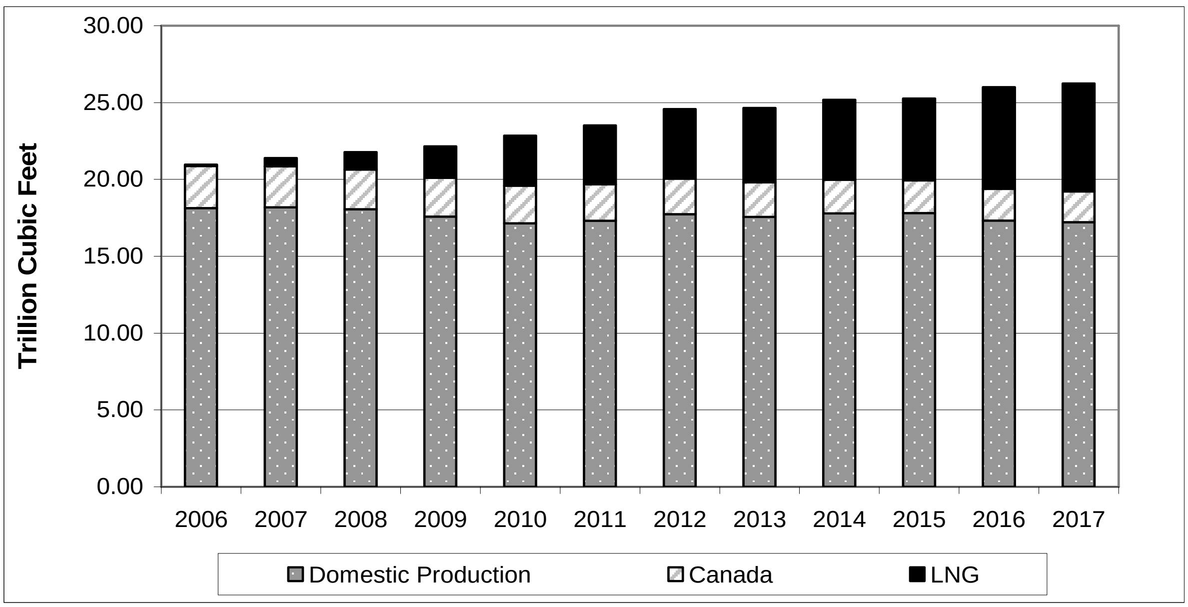
Supply

To put the supply view contained in the NARG 2007 reference case in perspective and to develop alternative views, R. W. Beck again compared staff's projections with other forecasts. Beck then developed a simple heuristic device to provide a "snapshot" of how changes in a few key component variables create very different supply pictures. Beck illustrates a set of assumptions that replicate staff's reference case for supply and show how possible changes to those assumptions create different supply views.

The difference between supply and demand becomes a "gap." The term "gap" is used figuratively in the heuristic because all good analysts know that price is the mechanism that balances (or rations) supply to equal demand. In reality, there is no gap. Beck's purpose here, rather, is to highlight the policy choices available when U.S. domestic production differs (for whatever reason) from demand. Those policy choices come down to three: (i) import LNG, (ii) increase domestic production, or (iii) reduce demand. The "gap" in the high supply case developed below turns out to be very similar to EIA's reference case and leaves an approximately 3-Tcf "gap" between domestic supply and demand by 2017; in contrast, the low case leaves an approximately 10-Tcf "gap" between domestic supply and demand by 2017.

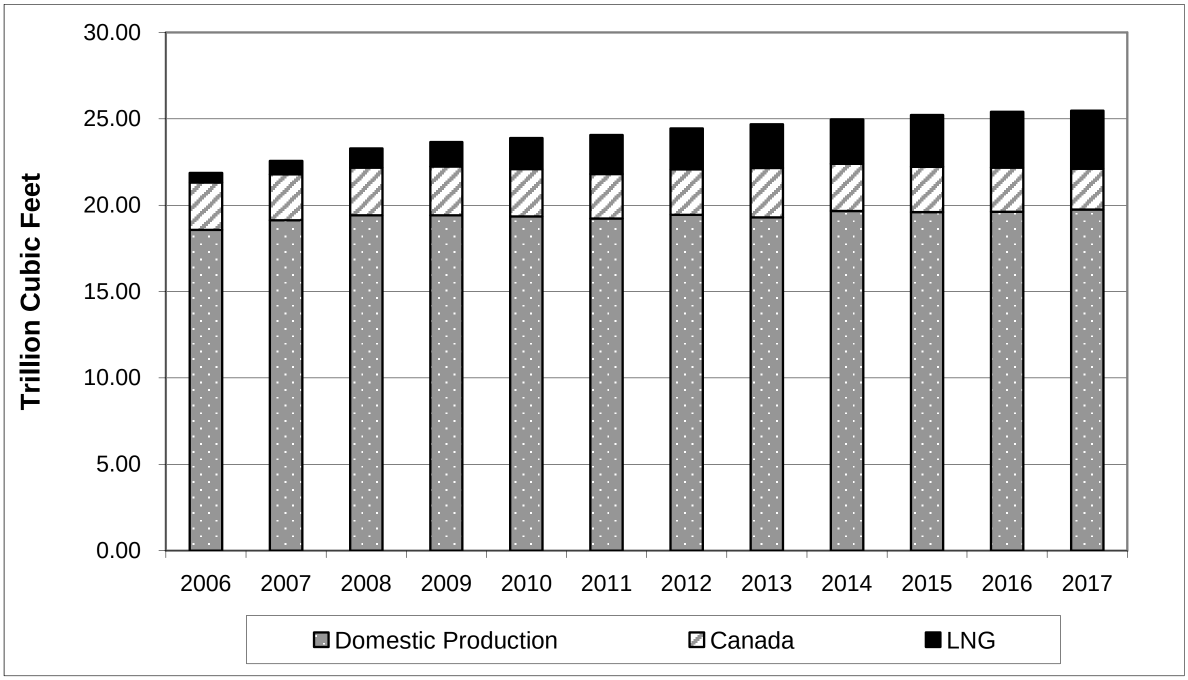
Figure 59 displays the key components of U.S. natural gas supply from the reference case.

Figure 59: NARG Reference Case – U. S. Natural Gas Supply



Source: R. W. Beck, 2007

Figure 60: EIA AEO Reference Case – U.S. Natural Gas Supply



Source: R. W. Beck, 2007

Figure 60 displays those components from EIA's *Annual Energy Outlook* reference case.

Staff's NARG reference case shows lower U.S. domestic production than the reference case in EIA's *Annual Energy Outlook*, leaving more demand to be met by LNG.

Why might U.S. natural gas supply be lower or higher than estimated in staff's NARG reference case? Reasons include:

- Uncertainty over production costs and the ability to produce more from an increasingly unconventional resource base.
- Uncertainty over investment patterns and technological development.
- Uncertainty over Canadian production and the volume available for the United States to import: declines plus use for tar sands production reduce exports to the United States versus relatively stable production.
- Uncertainty over LNG availability, cost, access, and the global supply/demand balance.

Production Cost Uncertainty and Declining Resource Base

The NARG 2007 reference case removed 32 Tcf of probable reserves to recognize slightly higher production costs at every level of output. Other data provide corroborative evidence of increasing production costs.

Tristone Capital provided Energy Commission staff with its analysis based on the financial statements of approximately eight of the large independent natural gas exploration and production companies (Apache, Devon, EOG, EnCana, and others). Note that average finding and development costs from 2002 to 2007 (**Table 16**) more than doubled for the sample set of companies.

Table 16: Average North American Natural Gas Cost Structure (Weighted Average)

	2002	2003	2004	2005	2006	2007
Operating Expense	0.53	0.68	0.78	0.92	1.03	1.15
Production & Mineral Tax	0.12	0.17	0.23	0.29	0.31	0.33
Transportation	1.07	1.19	1.06	1.27	1.24	1.24
General & Administrative	0.12	0.15	0.15	0.19	0.25	0.28
Cash Costs	1.84	2.19	2.21	2.67	2.84	3.01
Finding & Development (incl. Future Capital)	1.77	1.93	2.15	2.70	4.23	4.87
Total Supply Cost US$/Mcf	3.61	4.12	4.37	5.36	7.06	7.88
Percent Change		14%	6%	23%	32%	12%

Source: Tristone Capital, E=estimated

The American Petroleum Institute (API) drilling costs (**Table 17**) show a similar result. API shows that the average cost of all wells drilled has increased by 80 percent since 2001. Costs have increased at each depth interval. Drilling costs for wells in the 10,000- to 12,499-foot and 17,500- to 19,999-foot ranges have nearly doubled.

Table 17: API Joint Association Survey on Drilling Costs – Total United States (Footage in Feet, Costs in Thousands of Dollars)

Depth Interval	2001			2003			2005		
	No. of Wells	Avg. Depth	Avg. Cost	No. of Wells	Avg. Depth	Avg. Cost	No. of Wells	Avg. Depth	Avg. Cost
0–1,249	4,658	797	$ 87	2,466	860	$ 131	2,534	862	$ 201
1,250–2,499	2,999	1,748	179	2,730	1,793	193	4,387	1,791	268
2,500–3,749	1,993	3,182	230	2,336	3,179	263	2,994	3,139	351
3,750–4,999	1,652	4,279	307	1,838	4,335	315	2,207	4,329	445
5,000–7,499	3,002	6,218	557	2,853	6,319	611	3,159	6,206	911
7,500–9,999	2,747	8,582	1,115	3,277	8,561	1,140	3,457	8,715	1,867
10,000–12,499	1,810	11,095	1,872	1,814	11,144	2,325	2,388	11,052	3,234
12,500–14,999	960	13,422	3,125	1,053	13,366	3,250	1,254	13,488	5,246
15,000–17,499	248	15,981	6,075	244	16,023	6,734	293	15,995	8,498
17,500–19,999	100	18,440	8,245	80	18,543	12,808	94	18,315	15,793
20,000 +	17	21,474	16,014	23	21,368	16,038	21	20,906	20,605
Total	20,186	5,140	775	18,714	5,807	972	22,788	5,656	1,394

Note: Gas Wells Only; Source: Lippman Consulting Inc.

Uncertainty Over Investment Patterns and Technological Development

Production per new well has declined dramatically over the last eight years. It is not clear whether this is due to drilling smaller fields into production or whether it is the inevitable result of new technology that allows the harvest of unconventional resources that by their nature produce less per well. Such wells may be more costly but present lower risk to producers than new exploration. Thus, those who claim the United States cannot produce more natural gas confuse cause with effect and misunderstand the economic drivers that push producers to focus on a quick return infill drilling.

R. W. Beck analyzed data from Lippman Consulting for the number of wells completed and production from those wells between 1999 and 2006. The analysis, presented in Table 18, demonstrates that production per well in 2006 was nearly half what it was in 1999. This represents a 7 percent per year annual decline. Beck used the production per well data to assess how many wells would be needed to produce 2.5 Tcf of natural gas. 2.5 Tcf was selected because it nominally represents the amount of gas lost to depletion (assuming an 11 percent aggregate depletion rate and production of approximately 22 Tcf). Essentially, **Table 18** shows how many wells have to be completed just to keep production constant. As production per well declines, the number of wells that have to be drilled and completed to make up 2.5 Tcf has essentially doubled. To the extent that production per well declines but the required number of wells are not drilled and completed, domestic supply will be insufficient. Conversely, to the extent that production per well increases, fewer wells must be drilled and completed.

Table 18: Change in Production per New Well Drilled

Year	Production per New Well		Wells Required to Produce 2.5 Tcf
	Bcf	MMcfd	
1999	0.162	0.444	15,432
2000	0.132	0.361	18,981
2001	0.123	0.337	20,325
2002	0.124	0.340	20,161
2003	0.114	0.312	21,930
2004	0.110	0.301	22,727
2005	0.096	0.263	26,042
2006	0.091	0.249	27,473
Annual Rate	-7.0%		

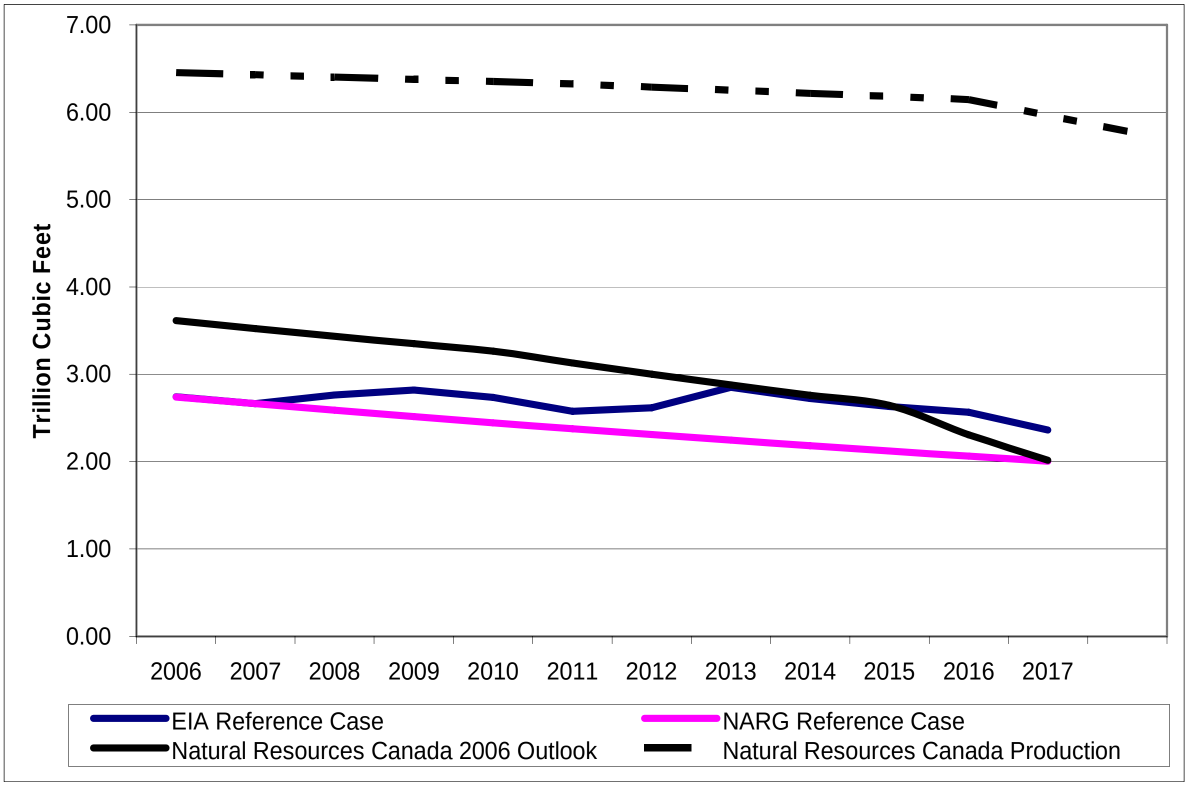
Source: Lippman Consulting, Inc. and R. W. Beck, Inc.

Uncertainty over Canadian Production and the Amount Available for Import to the United States

Uncertainty over Canadian production and the volume that will be available for the United States to import is another reason why U.S. natural gas supply may be lower or higher than staff estimated in its reference case. Declines in production plus use for tar sands production reduce exports to the United States.

Natural Resources Canada projected in its 2006 Outlook that its natural gas production would decline by about 0.7 Tcf by 2017. Exports would decline by more, owing to greater use of natural gas to process tar sands oil. In **Figure 61**, staff's NARG reference case shows Canadian supply available to the United States declining by about 2.5 percent per year; EIA's *Annual Energy Outlook* reference case shows a smaller decline of about 1.2 percent.

Figure 61: Forecasts of Natural Gas Exports from Canada to U.S.

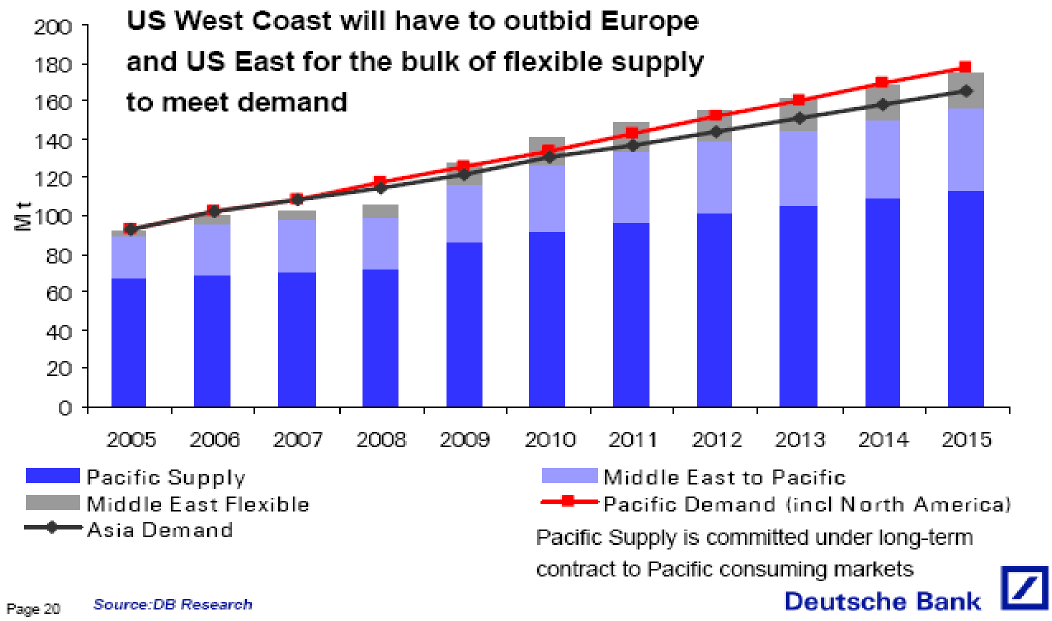


Source: R. W. Beck, 2007

Uncertainty of Multiple LNG Factors

Uncertainty over LNG availability, cost, and access and the global supply/demand balance could also account for variance between actual U.S. natural gas supply and that estimated in staff's NARG reference case. For example, there is considerable disagreement over the volume of LNG that will find its way to the United States and the price it will take to attract it. While economists expect that LNG will trade at the prevailing U.S. market-clearing price as long as it is infra-marginal supply (if it becomes marginal it will set the market-clearing price), it is unclear what price it will take to give LNG suppliers sufficient netback to make the United States an attractive market relative to other global markets. This underlying cost question is more acute for foreign LNG production than domestic production because less is known about the cost of foreign production and the economics of LNG trading patterns. A Deutsche Bank presentation (**Figure 62**) points out that the West Coast may have to pay more for LNG as its price is bid up.

Figure 62: Deutsche Bank Identifies Potential Pressure on LNG Costs from Demand-Pull Perspective



Source: http://www.energyusa-tpc.com/uploads/newsletter-documents/9V5eVw20070308090232.pdf

Altos' WGTM/NARG allows LNG flows into the United States when the sum of expected liquefaction, transportation, and regasification costs are lower than the U.S. market-clearing price of natural gas — that is, when the delivered cost of LNG (excluding netback) is the next economic resource. If the LNG costs specified in the model are "too low," then NARG will sequence "too much" LNG relative to U.S. production and the resulting market-clearing prices will be "too low."

In the revised/final Reference Case, staff constrained the number of regasification terminals to those terminals under construction now or for which expansions have been approved. This reduced the amount of LNG imports to 14 Bcf per day (compared to 24 Bcf per day in the preliminary case). Staff imposed this constraint because LNG developers themselves, in their comments on the preliminary draft, told the Energy Commission that 24 Bcf per day was too high. The revised/final case of 14 Bcf per day is consistent with the global LNG trade outlook Jensen Associates prepared for the Energy Commission. The Jensen study is not based on global economic dispatch of LNG, but a compilation of terminals under construction and understanding of world LNG trade patterns and long-term contracts. Its base case projects world LNG supply of 14.9 Tcf (40 Bcf per day) by 2015. Staff's preliminary reference case projected approximately 60 percent of that coming to North America; the revised/final case reduces that to approximately 35 percent. Note also that all of these projections assume that LNG cargo deliveries occur on a smooth, constant basis. This may or may not be realistic.

R. W. Beck has prepared a simple heuristic device to help evaluate the NARG reference case supply scenario and create alternative views. The heuristic device makes it possible to test the key variables that contribute to the U.S. supply mix — what it takes to create higher levels of U.S. production or Canadian supply and how that translates to higher or lower levels of LNG imports. The heuristic device also makes it possible to test supply scenarios against higher or lower demand scenarios at a glance.

$$\text{Supply}_t = (\text{Domestic Production}_{t-1} - \text{Annual Depletion}_t + \text{New Wells Production}_t) + \text{Pipeline Imports}_t + \text{LNG}_t$$

Adding demand to the above equation and rearranging yields:

$$\text{Demand}_t - (\text{Domestic Production}_{t-1} - \text{Annual Depletion}_t - \text{New Wells Production}_t) - \text{Pipeline Imports}_t = \text{LNG}_t$$

Table 19 restates staff's NARG reference case in the form of the heuristic calculation.

The aggregate depletion rate of 11.6 percent is calculated from Lippman Consulting data and represents total depletion for all wells in production. R. W. Beck allowed aggregate depletion to increase at 2 percent per year. Column E in Table 19 shows the number of new wells required to meet the NARG reference case domestic production forecast. It is calculated by dividing domestic production needed less supply after depletion by the production per well shown in Column F. Production per new well is assumed to decrease at 4 percent per year based on data from Lippman Consulting. Four percent is the rate of decrease from 2002 to 2006. Canadian exports to the United States are assumed to decline in proportion to the production decline forecast in the NARG reference case. Column L shows demand remaining that must be met by other sources, presumably LNG. Note that by changing the aggregate depletion rate, production per well, and number of wells completed, one changes the resulting level of U.S. domestic production. Comparing that amount, plus net imports from Canada, to demand, indicates whether there will be enough supply to meet projected demand.

A key observation of the reference case is that nearly 60,000 wells must be completed by 2017. This is twice the number of natural gas wells completed in 2006, which was otherwise a record. If the theory that producers are investing in LNG because it provides a better risk/reward return than they can obtain from domestic production is correct (and note that both Altos and Global's models treatment of LNG are consistent with this theory), it is hard to imagine that producers will actually be willing to drill and complete 60,000 wells in the United States in 2017.

The high supply case (**Table 20**) illustrates assumptions that would create so much supply that no LNG is "needed." Depletion is again set at 11.6 percent and falls at 2 percent per year. The high supply case keeps production per well constant at 0.083 Bcf per new well. Column E, however, is set to drill and complete the same number of wells as in staff's reference case. By increasing production per well relative to the Reference Case yet completing the same number of wells, the heuristic ends up with much higher domestic production. Canadian supply is allowed to decrease at 1.23 percent per year, consistent with the assumption used in EIA's *Annual Energy Outlook* reference case (which is slightly more optimistic than staff's reference case). Higher domestic production and greater imports from Canada yield more total supply to meet demand. These two factors increase domestic production to 25 Tcf by 2017, compared with the NARG reference case of 20 Tcf. The difference left between supply and demand (assumed to be met by LNG) is shown in Column L. Note that the "gap" quantities shown are substantially smaller than in the NARG reference case.

The low supply case (**Table 21**) goes back to the NARG reference case assumption of a 4 percent decline in production per well. To create the lower supply, R. W. Beck modified the number of wells drilled to keep them constant at 30,000 wells per year, beginning in 2011. This supposes, essentially, that drilling cannot increase either due to lack of rigs, investment, or labor to drill beyond that amount: 30,000 wells are about the number drilled in 2006. Alternatively, the number of wells drilled could be allowed to increase and production per well allowed to decline by a larger annual percentage to achieve the same result. The low supply case retains the assumption that Canadian supply declines by 2 percent per year. With substantially less domestic supply, the result is a much larger "gap" to be met with LNG, shown in Column L.

Each case used this assumption. All else being equal, if U.S. supply is constrained and the Canadian supply declines more than assumed, then the gap met by LNG would increase; the converse is also true. Further, note that the display of the supply/demand balance in this fashion enables one to "eyeball" the result should the supply assumptions hold true but demand change.

Table 19: NARG Reference Case Restated

Tcf	A	B	C	D	E	F	G	H	I	J	K	L
	Last Year Dry Supply	Depletion Rate	Lost Via Depletion	Supply After Depletion	Number of New Wells	Production per New Well	Supply From New Wells	EIA Synthetic	Domestic Production	Canada (less export)	Demand NARG	GAP
Assumptions:		2.0%				-4.00%					Reference	
2006	18.23	-11.6%	-2.06	15.67	29,627	0.0830	2.46	0	18.57	2.74	21.5	0.23
2007	18.57	-11.8%	-2.15	15.99	37,720	0.0797	3.01	0	19.38	2.87	22.1	-0.12
2008	19.38	-12.1%	-2.20	15.99	31,961	0.0765	2.44	0	19.49	2.48	22.4	0.46
2009	19.49	-12.3%	-2.22	15.83	31,102	0.0734	2.28	0	19.37	2.25	22.9	1.31
2010	19.37	-12.6%	-2.21	15.36	35,513	0.0705	2.50	0	19.44	2.28	23.5	1.75
2011	19.44	-12.8%	-2.20	14.94	42,857	0.0677	2.90	0	19.85	2.38	24.3	2.08
2012	19.85	-13.1%	-2.26	15.05	48,895	0.0650	3.18	0	20.44	2.75	25.3	2.07
2013	20.44	-13.3%	-2.36	15.38	39,540	0.0624	2.47	0	20.18	2.73	25.5	2.62
2014	20.18	-13.6%	-2.39	15.17	41,394	0.0599	2.48	0	19.92	2.69	25.8	3.23
2015	19.92	-13.9%	-2.47	15.32	46,109	0.0575	2.65	0	19.81	2.60	26.3	3.86
2016	19.81	-14.1%	-2.52	15.29	54,425	0.0552	3.00	0	20.01	2.40	26.7	4.27
2017	20.01	-14.4%	-2.50	14.82	59,728	0.0530	3.16	0	20.29	2.22	27.1	4.57

Source: R. W. Beck, 2007

Table 20: High Supply Case

Tcf	A	B	C	D	E	F	G	H	I	J	K	L
	Last Year Dry Supply	Depletion Rate	Lost Via Depletion	Supply After Depletion	Number of New Wells	Production per New Well	Supply From New Wells	EIA Synthetic	Domestic Production	Canada (less export)	Demand NARG	GAP
Assumptions:		2.0%								-1.23%	Reference	
2006	18.23	-11.6%	-2.11	16.12	29,627	0.0830	2.46	0.07	18.57	2.74	21.5	0.16
2007	18.57	-11.8%	-2.20	16.38	37,720	0.0830	3.13	0.07	19.51	2.67	22.1	-0.11
2008	19.51	-12.1%	-2.31	17.15	31,961	0.0830	2.65	0.07	19.81	2.76	22.4	-0.21
2009	19.81	-12.3%	-2.39	17.37	31,102	0.0830	2.58	0.07	19.95	2.82	22.9	0.10
2010	19.95	-12.6%	-2.44	17.44	35,513	0.0830	2.95	0.07	20.39	2.74	23.5	0.28
2011	20.39	-12.8%	-2.48	17.78	42,857	0.0830	3.56	0.07	21.34	2.58	24.3	0.33
2012	21.34	-13.1%	-2.51	18.55	48,895	0.0830	4.06	0.07	22.61	2.62	25.3	-0.04
2013	22.61	-13.3%	-2.59	19.60	39,540	0.0830	3.28	0.07	22.88	2.85	25.5	-0.27
2014	22.88	-13.6%	-2.62	19.77	41,394	0.0830	3.44	0.07	23.20	2.72	25.8	-0.17
2015	23.20	-13.9%	-2.73	19.99	46,109	0.0830	3.83	0.07	23.81	2.63	26.3	-0.25
2016	23.81	-14.1%	-2.77	20.45	54,425	0.0830	4.52	0.07	24.96	2.57	26.7	-0.92
2017	24.96	-14.4%	-2.83	21.36	59,728	0.0830	4.96	0.07	26.32	2.36	27.1	-1.68

Source: R. W. Beck, 2007

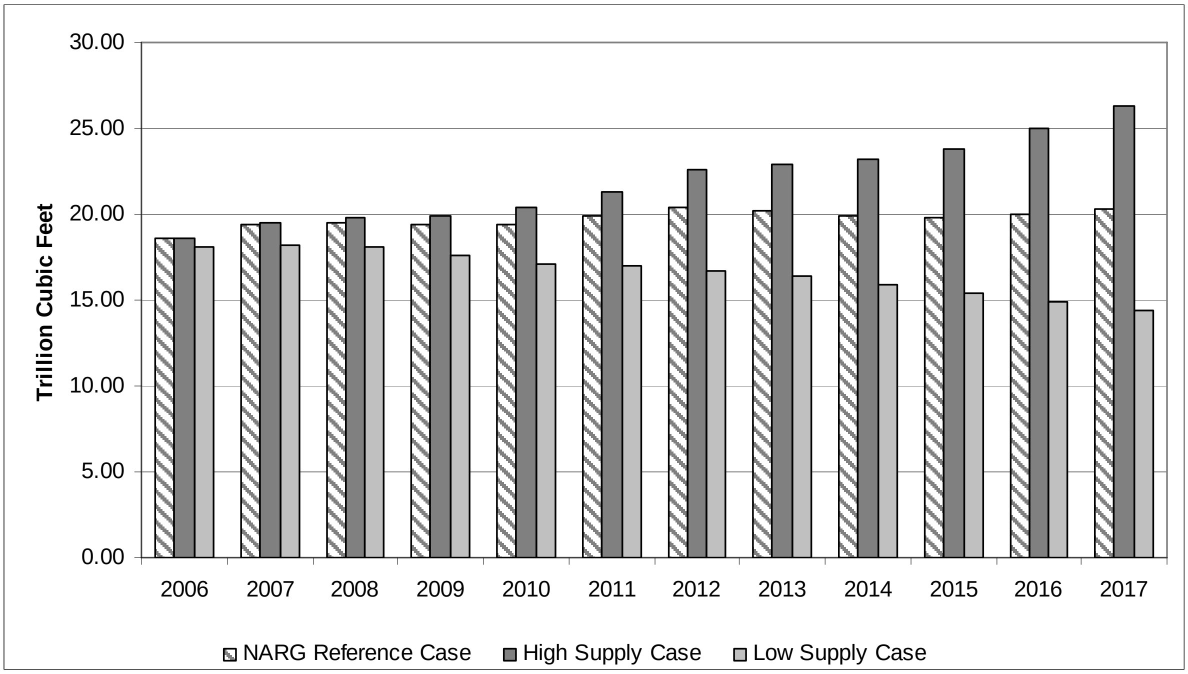
Table 21: Low Supply Case

Tcf	A	B	C	D	E	F	G	H	I	J	K	L
	Last Year Dry Supply	Depletion Rate	Lost Via Depletion	Supply After Depletion	Number of New Wells	Production per New Well	Supply From New Wells	EIA Synthetic	Domestic Production	Canada (less export)	Demand NARG	GAP
Assumptions:		2.0%				-4.00%				-2.80%	Reference	
2006	17.73	-11.6%	-2.06	15.67	29,627	0.0830	2.46	0.00	18.13	2.74	21.54	0.67
2007	18.13	-11.8%	-2.15	15.99	27,640	0.0797	2.20	0.00	18.19	2.87	22.14	1.08
2008	18.19	-12.1%	-2.20	15.99	26,917	0.0765	2.06	0.00	18.05	2.48	22.43	1.90
2009	18.05	-12.3%	-2.22	15.83	23,696	0.0734	1.74	0.00	17.57	2.25	22.94	3.12
2010	17.57	-12.6%	-2.21	15.36	25,185	0.0705	1.78	0.07	17.14	2.28	23.48	3.99
2011	17.14	-12.8%	-2.20	14.94	30,000	0.0677	2.03	0.00	16.98	2.38	24.31	4.96
2012	16.98	-13.1%	-2.22	14.76	30,000	0.0650	1.95	0.00	16.71	2.75	25.25	5.80
2013	16.71	-13.3%	-2.23	14.48	30,000	0.0624	1.87	0.00	16.35	2.73	25.53	6.45
2014	16.35	-13.6%	-2.22	14.13	30,000	0.0599	1.80	0.00	15.93	2.69	25.83	7.22
2015	15.93	-13.9%	-2.21	13.72	30,000	0.0575	1.72	0.00	15.44	2.60	26.26	8.22
2016	15.44	-14.1%	-2.18	13.26	30,000	0.0552	1.66	0.00	14.91	2.40	26.68	9.36
2017	14.91	-14.4%	-2.15	12.76	30,000	0.0530	1.59	0.00	14.35	2.22	27.07	10.51

Source: R. W. Beck, 2007

Figure 63 compares the U.S. domestic production calculated in each of the three cases. The three cases project U.S. production in the range of 18 Tcf in 2006. The NARG reference case increases production over time to approximately 20 Tcf by 2017. The high supply case grows production each year to nearly 26 Tcf by virtue of its assumed constant production per well and drilling a large number of wells. The low supply case moves consistently downward each year, with production falling to approximately 14 Tcf by 2017.

Figure 63: Domestic Natural Gas Production in Three Supply Cases



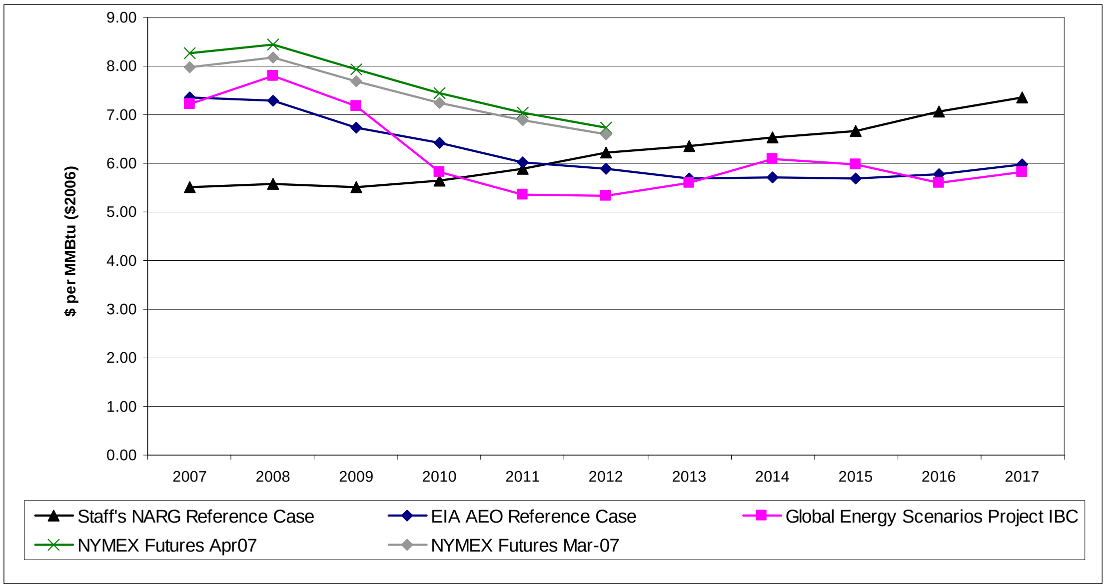
Source: R. W. Beck, 2007

Price

R. W. Beck did not generate an alternate forecast of natural gas prices but benchmarked staff's reference case to other forecasts. The comparisons show that staff's reference case is lower, by more than $2 per MMBtu in 2007 and 2008. By 2011, staff's forecast matches others. Staff's forecast increases steadily after 2011 as others rise and fall around the $6 per MMBtu level. By 2017, staff's forecast is slightly more than $1 per MMBtu above Global's (20 percent) and EIA's reference cases.

Figure 64 presents the graphical comparison of staff's NARG reference case with both the EIA *Annual Energy Outlook* reference case and a case prepared by Global Energy Decisions (Global) for the Energy Commission's Electricity Scenarios Project. Global's detailed methods and results are presented in a separate report. The graph also shows the NYMEX forward contract prices as traded at the end of March and in the middle of April. The figure shows that staff's NARG reference case prices are lower than forward prices during the first four years of the forecast period.

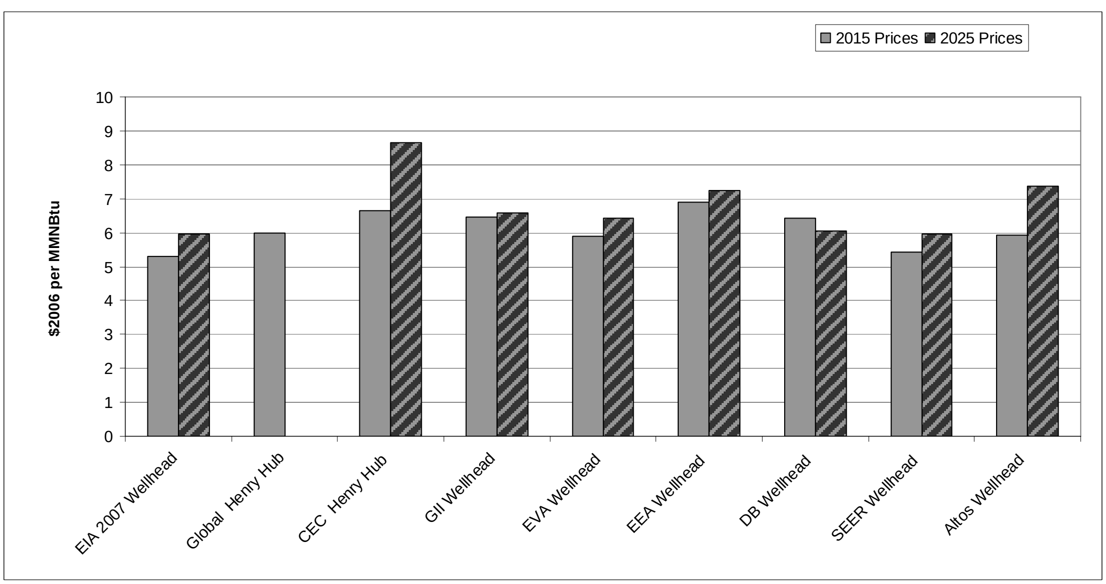
Figure 64: Benchmark of NARG Reference Case to Others



Source: R. W. Beck, 2007

The comparison to EIA is made for illustrative purposes because it is publicly available and, as shown in **Figure 65**, contains references to other forecasts.

Figure 65: Comparison of NARG Reference Case to Broader Set of Others in 2015 and 2025



Source: R. W. Beck, 2007

The reason for including Global's illustrative base case (IBC) forecast is that staff's NARG modeling is not the only work the Energy Commission is doing that involves modeling natural gas prices. Staff began the Scenarios Project work before it had even begun its NARG reference case work. Staff held a workshop on January 29, 2007, to discuss the Scenarios Project assumptions, including natural gas price.

The Scenarios Project uses, for certain analyses, what is termed the "illustrative base case" or IBC. The IBC is Global's Fall, 2006 reference case, adjusted for oil prices from EIA's *Annual Energy Outlook*. Global's IBC is not intended necessarily to imply that the IBC prices will occur, but rather provides a set of assumptions that staff could use to assess prices compared to the IBC as the scenario assumptions change. One should note that Global imposes NYMEX prices for the first 24 months of the period and then slowly reverts over the following 24 months to its own fundamental forecast. For NYMEX, it used an average of the closing prices on December 19–21, 2006. Since Global does not show the original prices produced from its model for that period, R. W. Beck cannot provide the Energy Commission with a direct comparison of Global's model results versus staff's for the early part of the forecast period.

In addition, Global constructed what it terms "P25" and "P75" cases, demonstrating its view of the range of uncertainty in natural gas prices. Global calls this a "stochastic" approach; it is not, however, the same as what R. W. Beck recommended using above. Global appears to develop its P25 and P75 using random draws around the reference case. R. W. Beck's recommendation, in contrast, is to develop probability distributions around each of the key uncertain variables and to perform a set of draws from each distribution.

Other work pertaining to natural gas prices is also underway under the auspices of the Energy Commission's Public Interest Energy Research (PIER) Program. That work includes some modeling of underground natural gas storage, its value, and how storage affects the price of natural gas and also includes an effort to build a monthly model of natural gas prices that captures the effect of storage on seasonal prices in California. The PIER results will not be available until very late in the IEPR process.

R. W. Beck also compiled a comparison of staff's reference case forecast to other forecasts shown in EIA's *Annual Energy Outlook*. The staff reference case is similar to several others in 2015 but higher than all others in 2025.

Based on its work with staff, R. W. Beck has identified two (and possibly three) key factors believed to drive staff's NARG reference case to be different than Global and EIA. Staff's forecast of North American natural gas demand is higher than EIA's. Staff did not prepare the forecast of natural gas demand beyond the WECC. R. W. Beck recommends that staff, in future IEPRs, seek to develop a complete picture of North American natural gas demand using consistent assumptions and models. The second key difference relates to LNG. While Global's model and Altos' WGTM/NARG model used by staff seem logically consistent in treating LNG as inframarginal, Global does not do a world dispatch of LNG. Altos' models do such a dispatch, but the underlying economics provided in the preliminary reference case results for North American LNG imports weren't "believable." Without a full vetting of the global economic assumptions underlying the WGTM, staff resorted to constraining LNG regasification capacity. Moreover, Global sees natural gas prices as being fundamentally driven by oil prices. NARG, as will be seen below, is relatively indifferent to oil prices, perhaps too much so. Despite these differences in approach and assumptions, the two models provide strikingly similar results.

The work done by staff for the *Natural Gas Assessment* and by Global in the Scenarios Project both appear to develop a key conclusion: LNG delivered to the United States beats out, on a cost basis, higher-cost elements of North American natural gas production, which results in keeping prices lower than they would be if no LNG came to North America. Less LNG requires higher domestic production to serve all demand. Prices rise as the quantity of domestic production moves up its supply curve. Staff's analysis shows that increasing domestic supply to replace the 3 to 4 Tcf of LNG removed from staff's initial reference case pushes natural gas prices in the revised/final reference case up by $1 to $2 per MMBtu by 2017. The message is that increasing domestic production to replace LNG, holding all else equal, requires higher natural gas prices.

The key market variables that could lead to high and low natural gas price projections are summarized in **Table 22**.

Natural gas market prices are influenced by a web of highly uncertain and interconnected variables. A stochastic forecasting approach that accounts for the randomness of these variables would provide the means to capture the probability distribution of future market prices. Considering the current deterministic approach employed by the Energy Commission, a multitude of carefully selected sensitivity cases evaluated using NARG would be necessary to provide a reasonable substitute for a stochastic approach. These sensitivity cases need to present a rational picture to some of the expected future scenarios for the natural gas industry and the economy.

Alternatively, Dr. Mike Donnelly of Global Energy feels that the correlation between oil and natural gas prices is very strong and he cited an article by the Federal Reserve Bank of Dallas, dated February 2007, titled: *What Drives Natural Gas Prices.* That article explains that there is a complex relationship between oil and gas prices that is affected by short-term dynamics, such as weather seasonality, supply, and storage disruptions. These short-term dynamics tend to mask the stable long-term relationship. The paper does say however that "there is a continuum of market links between natural gas and crude oil prices. Natural gas prices are anchored in a long-term relationship with crude oil prices, but the short-term dynamics can result in considerable variation in relative natural gas and crude oil prices."

Table 22: Variables Creating Alternate Price Cases

Drivers	High Price Case	Low Price Case	Scope
Policy Variables			
Efficiency Policy	Slow enactment of legislation/ implementation	Aggressive enactment and implementation of policies	National
Conservation Policy	Slow enactment of legislation/ implementation	Aggressive enactment and implementation of policies	National
Carbon-reduction Policy	Aggressive enactment and implementation of policies	Slow enactment of legislation/ implementation	National
Cost of Carbon Reduction	High cost $/Ton of CO2 reduction (~ above $15)	Low cost $/Ton of CO2 reduction (~ $5 - $15)	National
Demand Variables			
Coal Generation	No or little capacity additions	50% of new capacity additions	WECC
Nuclear Generation	Business as usual	Progress in licensing proposed plants	National
Renewable Generation	Slow enactment of legislation/ implementation + No major breakthrough in technology and costs	Aggressive enactment and implementation of policies + major breakthrough in technology and costs	National
Economic Growth	High growth scenario	Slow growth scenario	National
Supply and Infrastructure Variables			
Electric Transmission	Critical regional paths are congested	Major transmission capacity expansions into California	California
Pipeline Expansion	New pipelines focus on delivery to Midwest or East leaving less gas for West	Pipelines expand with new production to deliver gas to West	WECC California
North American New Gas Production	Flat production growth	Aggressive investment leads to overproduction and/or finding new fields	National
LNG Imports	Less than 3 TCF per year by 2017	Large Imports of LNG (>8 TCF per year by 2017) allow reduced drilling	National
LNG Costs	Increasing worldwide construction costs cause spiral in liquefaction, shipping, and regasification costs	LNG cost plus netback makes LNG more economic than North American production	National
Investment Pattern	Continued focus on short-producing wells	Focus on North America and longer-term view	National
Technology	No change or continued decline in production per well	Technology breakthroughs increase production per well	National
New Leases	Status quo	Open new areas to drilling	National

Source: R. W. Beck, 2007

Sensitivity Cases

Staff prepared four sensitivity cases to test alternatives relative to the reference case. The cases are as follows:

- A simulation of dry hydro conditions.
- A 1 Bcf per day LNG terminal in Southern California, operational in 2011.
- A 1 Bcf per day LNG terminal in Southern California, operational in 2011 and expanding in 2015.
- A 1 Bcf per day LNG terminal in Southern California, operational in 2011 and a 1 Bcf per day LNG terminal in the Pacific Northwest, operational in 2015.

The major findings of the World Gas Trade/ North American Regional Model (WGTM/NARG) sensitivity runs are as follows:

- Increasing the WECC power generation demand adds upward pressure on ($2006) prices. By the end of the forecast horizon, prices rise by about $0.15 to $0.20/Mcf.

- LNG flows from regasification terminals in Southern California and in the Pacific Northwest displace California's traditional sources of natural gas supplies.

- In all three LNG cases, the insertion of LNG regasification terminals produces price reductions that, in most years of the forecast horizon, vary between $0.15/Mcf and $0.60/Mcf.

Appendix E provides further details about the four sensitivities.

Relationship Between Oil and Natural Gas Prices

The NARG model staff used to prepare its reference case includes oil prices as an input assumption. In developing the preliminary assessment, staff evaluated two cases using high and low oil prices to understand what effect those higher and lower oil prices might have on projected natural gas prices. R. W. Beck was asked to provide some background and analysis on the general relationship between oil and natural gas prices.

Interestingly, nearly everyone has an opinion on whether oil prices matter in forecasting natural gas prices. Global includes them as a key driver to its natural gas price model. Altos includes oil prices but gives them little weight. As one might therefore expect, there remains more debate than consensus about the relationship between oil and natural gas prices and the nature of that relationship. Aside from the historical statistical relationship between oil and natural gas prices, oil prices have an effect on overall economic activities such as consumption behavior, productivity, profitability, and investment. Therefore, a review of the effect and relationship of oil prices to the overall economy is in order first.

Effects of Higher Oil Prices

Higher oil prices affect economic activity in many different ways. The following observations briefly review some common thoughts about the effects of high oil prices:

- Higher oil prices reduce the spending capacity of consumers and cause a reduction in demand for all of their spending categories.
- Rising oil costs reduce profit margins for companies when they are not able to pass these costs on to their customers. This is especially true for firms in energy intensive sectors, causing the firms to reduce services or cut production levels.
- Higher oil prices spark fears of a price-wage escalation and cause monetary authorities to tighten credit conditions. This, in turn, weakens investment spending, housing, and sales of durable goods like automobiles.
- Higher oil prices hurt both consumer and investor confidence. As equity prices decline, household wealth declines, and the economy is weakened.
- The U.S. economy is in a better position now to weather oil price shocks than it was in the past because it is less oil-intensive. The United States uses half as much oil to produce the same amount of GDP as it did in the 1970s. The rate of decline in oil use relative to the economy, however, has slowed in recent years.
- Oil still plays a significant role in the U.S. and world economies. The United States transportation sector relies on oil for 97 percent of total U.S. oil demand. Because the transportation sector remains nearly wholly dependent on oil, consumers cannot quickly reduce consumption in response to higher prices.

Obviously, the extent of these impacts is a function of how high and persistent oil prices are. The cumulative effects of high oil prices on economic activity eventually affect natural gas demand as well as levels of investment and development.

The Observed Relationship Between Natural Gas and Oil Prices

For many years, natural gas and refined petroleum were seen as close substitutes in U.S. industry and electric power generation. Industry and electric power generators switched back and forth between natural gas and residual fuel oil, using whichever energy source was less expensive. In the northeast United States, fuel oil is still often used instead of natural gas to heat homes. Consequently, it has been observed that U.S. natural gas price movements generally tracked those of crude oil. In addition, natural gas was originally viewed as a mere byproduct of producing oil. The exploration and production processes are similar, and the same companies look for and produce both natural gas and oil.

The following observations highlight this relationship:

- Oil and natural gas are competitive substitutes primarily in the electric generation and industrial sectors.
- According to EIA, 18 percent of natural gas usage by manufacturers can be switched to oil products (The EIA *Manufacturing Energy Consumption Survey* [MECS], 2002).
- According to the National Petroleum Council (2003), 20 percent of power generation capacity is dual-fired, but in practice very little capacity switches to oil.
- Additional fuel switching is achievable by generation dispatching, although limited because of environmental constraints.
- High oil prices lead to an increase in oil production. High oil production increases natural gas production as a co-product (associated natural gas production in 2005 was about 2.7 TCF, 14 percent of all natural gas production in the United States).
- High oil prices also increase revenues and cash available for oil and natural gas companies, which lead to higher capital spent on drilling and development of new natural gas projects.
- LNG contracts in the global market were historically indexed to oil prices. Many analysts expect new contracts to use natural gas indices as their pricing mechanism.

Market analysts generally identify weather and seasonal natural gas storage levels as key drivers of natural gas prices. Using an error-correction model,[7] Brown and Yücel show that when these and other additional factors are taken into account, movements in crude oil prices have a prominent role in shaping natural gas prices. Their findings imply a range of prices at which natural gas and petroleum products are substitutes.

In an affirmation of these observations, Bachmeir and Griffin (2006) find a weak relationship between oil and U.S. natural gas prices. In contrast, a more recent study by Villar and Joutz (2006) find oil and natural gas prices to be integrated with a trend. The dynamic relationship they find between the oil and natural gas prices suggests that a one-month temporary shock to West Texas Intermediate (WTI) of 20 percent has a 5 percent contemporary impact on natural gas prices but dissipates to 20 percent in two months. Also, they find that a permanent shock of 20 percent in WTI prices leads to a 16 percent increase in the Henry Hub prices one year out, all else being equal. They concluded that oil prices influence the long-run development of natural gas prices but are not influenced by them.

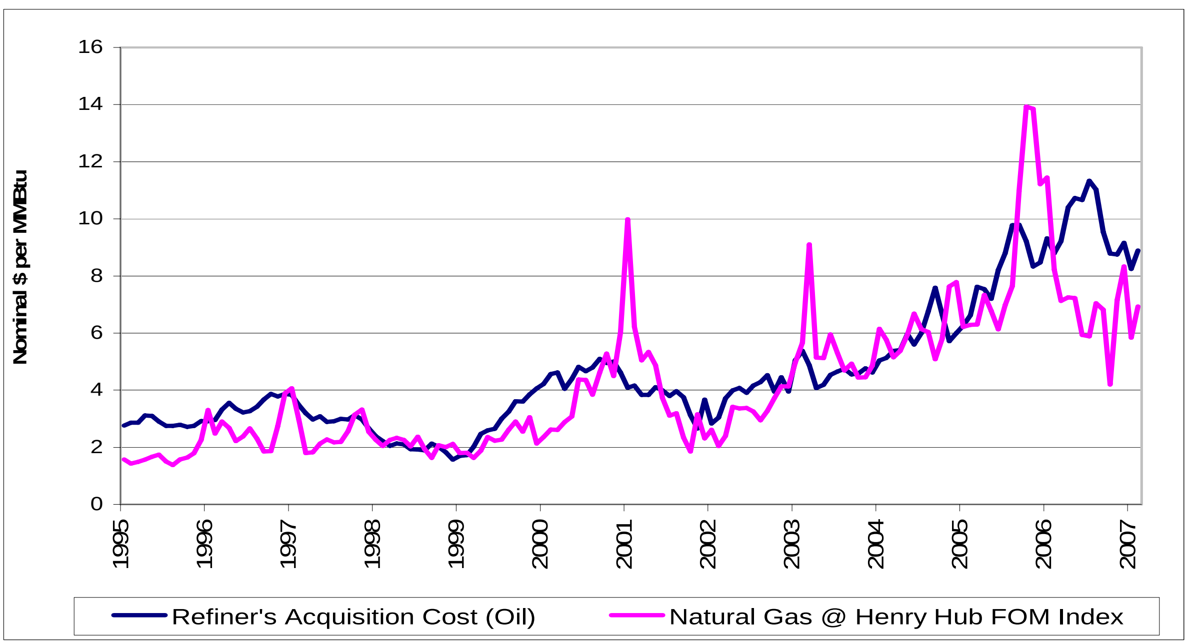
Figures 66 and 67 show the historical movement of natural gas prices versus the equivalent oil prices in $/MMBtu and the movements of crude, residual, and distillate oil prices. It is noteworthy, as shown in Figure 66, that oil and natural gas prices do appear to have moved upward on generally parallel paths most of the time from 1995

[7] Stephen P. A. Brown and Mine K. Yücel, Federal Reserve Bank of Dallas, *What Drives Natural Gas Prices?*, February 2007

to 2005. Natural gas prices display large winter spikes that oil prices do not display. During such periods, natural gas can be said to have traded at a “premium” to oil prices.

Since late 2005, natural gas prices are clearly less linked to oil prices. They are shown on the graph to be lower than oil prices, and thus can be said to be trading at a “discount” to oil. The use here of the terms “premium” or “discount” is different than the notion that natural gas prices are currently trading at premium levels relative to cost or certainly that NYMEX forwards in the $7 to $8 per MMBtu or higher range appear to demonstrate a premium relative to cost. This is sometimes known as the “fear” premium. The fear is that natural gas supply is “tight” enough that supply will be unable to respond to either another Katrina-type disruption or an extreme peak demand period. Thus, forward prices remain high as the market “worries” about being caught short; spot prices remain “sticky” and fall only when the market is faced with overwhelming evidence of excess supply, such as October 2006 when the combination of full storage and low demand temporarily pushed prices down to approximately $4 per MMBtu.

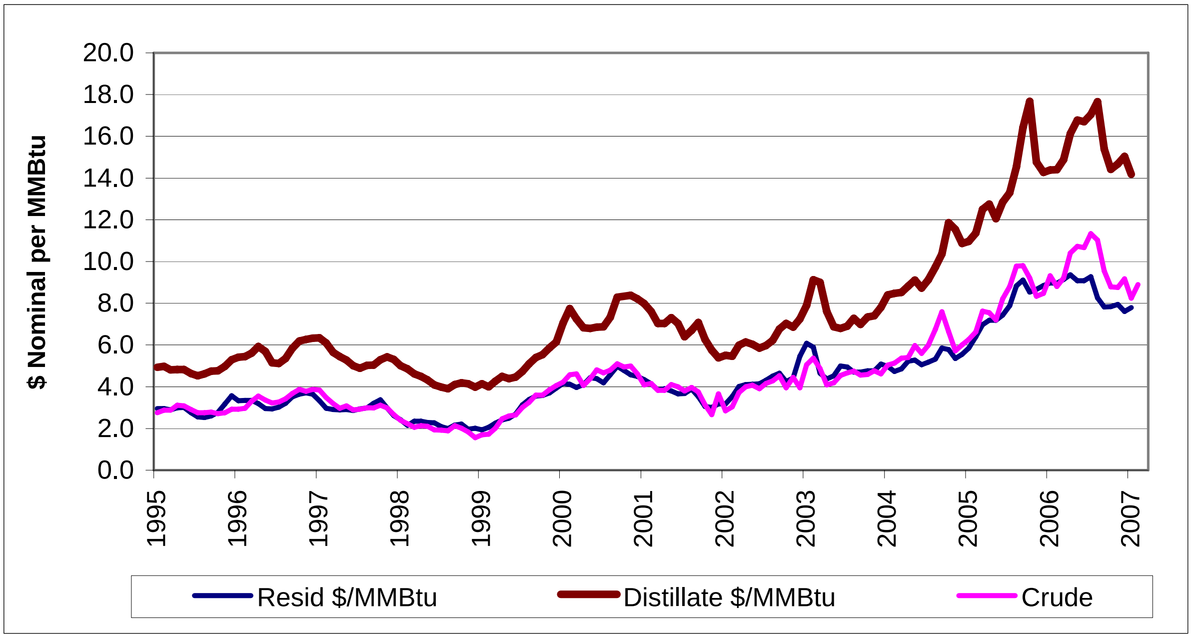
Figure 66: Natural Gas and Equivalent Oil Prices
($ Nominal/MMBtu)



Source: R. W. Beck, 2007

Figure 67 depicts the historical relationship between crude oil and residual oil prices. Residual oil, which has more (albeit, limited) potential substitutability with natural gas than all other refined petroleum products, is sometimes a price taker during periods in which its prices are slightly decoupled from crude oil and other refined product prices. As should be expected, the more refined distillate trades at a premium to crude, while residual oil trades at prices very close to crude oil. Between 1995 and perhaps as late as 2004, distillate appears to have traded at a relatively constant differential to crude oil; beginning in early 2005, that premium appears to have increased, in relative terms, as demonstrated by a widening gap between the two price streams.

Figure 67: Equivalent Crude Oil, Residual, and Distillate Oil Prices

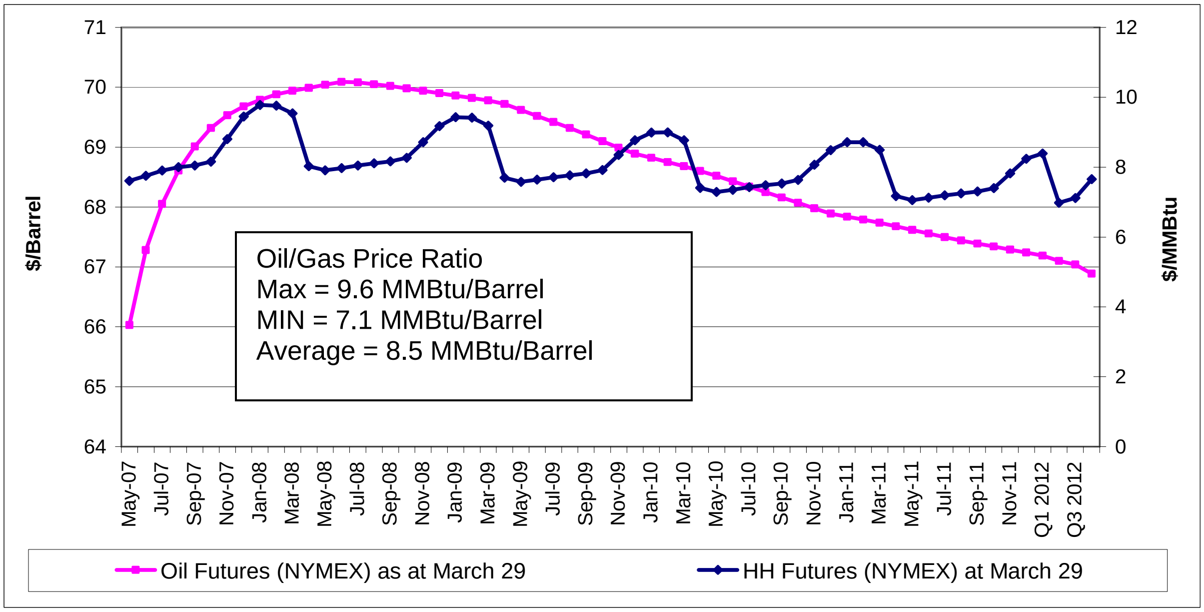


Source: R. W. Beck, 2007

Figure 68 depicts the oil-to-natural gas price ratio embodied in NYMEX forward monthly contracts traded on March 29, 2007. The average ratio in MMBtu per barrel is 8.5 with a range of 7.1–9.6. It is important to note that the ratio is not a constant, indicating that the two price streams do not move together.

In summary, based on the reviewed literature and market data observations, the relationship between oil and natural gas prices is complex: there *is* a relationship, but it is difficult to characterize and it is not constant. This finding appears to be somewhat consistent with the sensitivity case results produced by staff's modeling work, which demonstrates an asymmetric effect from changes in oil prices, with higher oil prices having little effect on natural gas prices, while lower oil prices have a much larger one.

Figure 68: NYMEX Oil and Natural Gas Futures as of March 29, 2007



Source: R. W. Beck, 2007

APPENDIX A: ELECTRIC GENERATION AND TRANSMISSION INFRASTRUCTURE DEVELOPMENT ASSUMPTIONS 2008-2017

Method to Develop Infrastructure Assumptions

EAO staff conducted a 10-year simulation for the forecast period 2008-2017 using Global Energy Decisions (GED) MarketSym model. Changes to the GED dataset included using the Energy Commission DAO forecast for California peak demand and annual energy requirements, and the natural gas price forecast developed by the Energy Commission Natural Gas Unit (NGU). The supply-side resource mix included existing resources and high-probability, named resource additions, as well as staff's best estimate of expected generic renewable energy units that may be added. The data used to develop this staff estimate includes the Long-Term Procurement Plans (LTPP) provided by PG&E, Southern California Edison (SCE), and SDG&E. These renewable units were added to the dataset as an attempt to mimic possible future system conditions given the mandated renewable portfolio standards now in place in many states in the Western Electricity Coordinating Council (WECC) for determining natural gas demand for utility electricity generation (UEG.) A more detailed description of what unit types were added and the method used to estimate these additions will be presented later in this appendix.

The results of the initial simulation were reviewed to provide an assessment of how well the model simulated actual system operations. The review included a check of simulation results including: energy not served, wholesale market clearing prices, transmission line loadings, and capacity factors for combustion turbines, steam turbines, and combined cycle plants. Hourly, monthly, and yearly simulation results were reviewed over the forecast. Close scrutiny was given to summer peak season results, most notably for system operations in California.

The results of the simulation did not reveal any obvious "red flags" or highly unusual predictions of system conditions. Near-term results that were observed could be considered plausible under "normal" conditions in the WECC (for example: market-clearing prices were not extremely high or low, capacity factors were consistent with historical operations data). Given that load growth continued throughout the WECC in the forecast period, in years six through ten of the simulation, market-clearing prices rose significantly, and some areas did experience energy shortages in later years due to "lumpy" resource additions.

System Buildout Generation Resources

Staff chose to begin the system resource buildout with renewable energy technologies due to the many state mandates that now exist throughout the WECC as renewable portfolio standards (RPS). While there are many factors to consider when resources are added to a portfolio, state mandates for renewable energy outweighed other considerations. Staff used inputs to the model that tried to reflect actual system conditions for renewable energy (for example: reduced capacity for wind resources during summer peak, operating profiles for solar resources based on historical data). Staff calculated renewable capacity additions by converting energy (GWh) into capacity (MW) using a simple formula and observed capacity factors for different technology types.

For California, shortfalls in meeting renewable energy targets were addressed by adding renewable generation based on investor-owned utility (IOU) public filings, known renewable energy projects, and in-state renewable energy potential. Different assumptions were made regarding annual procurement targets (APTs) and resource procurement for each IOU. For California publicly owned utilities (POUs), it was assumed that 10 percent of load would be served by renewable energy by 2013. A more detailed description of this process will follow later in this appendix.

For other states in the WECC with RPS mandates, staff used each of those states' specific legislative mandates to develop annual targets. Some state mandates give preference to specific renewable technologies or provide set-asides to require a percentage of renewable energy to be generated from a particular technology. These conditions were addressed by staff in the renewable energy assumptions.

Qualifying RPS generation from the simulation was compared to annual state targets to determine if surpluses or shortfalls existed. Based on the results, generic renewable additions were increased or curtailed so that annual procurement targets were achieved, or nearly achieved.

After adding generic renewable resources to the dataset, staff produced a load-resource balance report at the control area level using the MarketSym model. Using dependable capacity estimates for resources for the peak month for each control area, staff calculated the amount and type of capacity needed to bring control area resources up to a 15 percent (approximate) reserve margin. In some cases the annual reserve fell below this target, but it was assumed that excess capacity in neighboring areas would allow for energy to be imported to maintain reliability and prevent excessive wholesale energy prices. Using typical generic resource characterizations, staff added combustion turbines, combined-cycle plants, or coal-fired steam turbines, depending on the types and quantities of resources needed and the specific control areas in need of capacity.

Existing and Planned Transmission Path Development

Not only is the generation demand and supply infrastructure critical to natural gas demand for electric generation, so is the transmission infrastructure assumed and forecasted to be built. This section describes the method by which the transmission path infrastructure was upgraded to satisfy the demand and generation infrastructure upgrades described in the previous sections of this appendix.

The initial step in evaluating the existing western transmission system under EAO's base case was to find historical use of the major transmission paths. The year 2008 is considered the base case or benchmark year. **Figure A-1** illustrates the transmission infrastructure reasonably certain to be in available in 2008. Selected actual flows in the Western Interconnection from 1998 through 2003 were compiled for benchmarking purposes. Actual flows were not available for all paths in the WECC, but the flows that were studied indicate how the existing system is used to serve load. This information is also useful in the analysis and identification of potential future areas of congestion and for verifying staff modeling representation for production cost analysis. The information can also be used to understand anomalies where transmission scheduling is constrained despite actual flows being less than path transfer capabilities. However, it is not intended to be used to conclude whether there was significant congestion on a path. In addition, it cannot be concluded from this historical analysis that it is either necessary or economical to take any corrective actions for the loading levels reported. For some paths, the real-time optimal transfer capability (OTC) was not reported, and assumptions were made based upon WECC-published path transfer capabilities. These current assumptions are shown in **Table A-1.**

This study includes transmission expansion analyses under an average load forecast, average hydro conditions, and an average range for natural gas and coal prices. By 2017 this base case dataset includes *new generation development capacity* that is 55 percent natural gas-fired, 33 percent renewable, and 11 percent coal from a WECC perspective. For California, by 2017, the *new generation development* contains 59 percent natural gas-fired capacity and 41 percent renewable capacity.

Only major path upgrades that are approved by a regional transmission planning organization with financing were included before 2013 in the base case. For 2013 and beyond, production cost simulations were iteratively run to determine if generation was stranded and/or transmission paths were used above 75 percent on an annual basis and/or used at 100 percent during the time of a given regions peak. Once paths were identified for possible expansion for 2013 and beyond, staff considered and included some of the transmission projects proposed in utility RPFs, or those proposed by regional transmission planning studies and organizations. The final transmission plan is shown in **Figure A-2** (located at the end of this appendix) and includes more than 15,000 MWs of transmission path upgrades between 2009 and 2017 in the WECC. See **Table A-1** for more details regarding the timing of each of the assumed path upgrades.

Figure A-1: WECC 2008 Topology

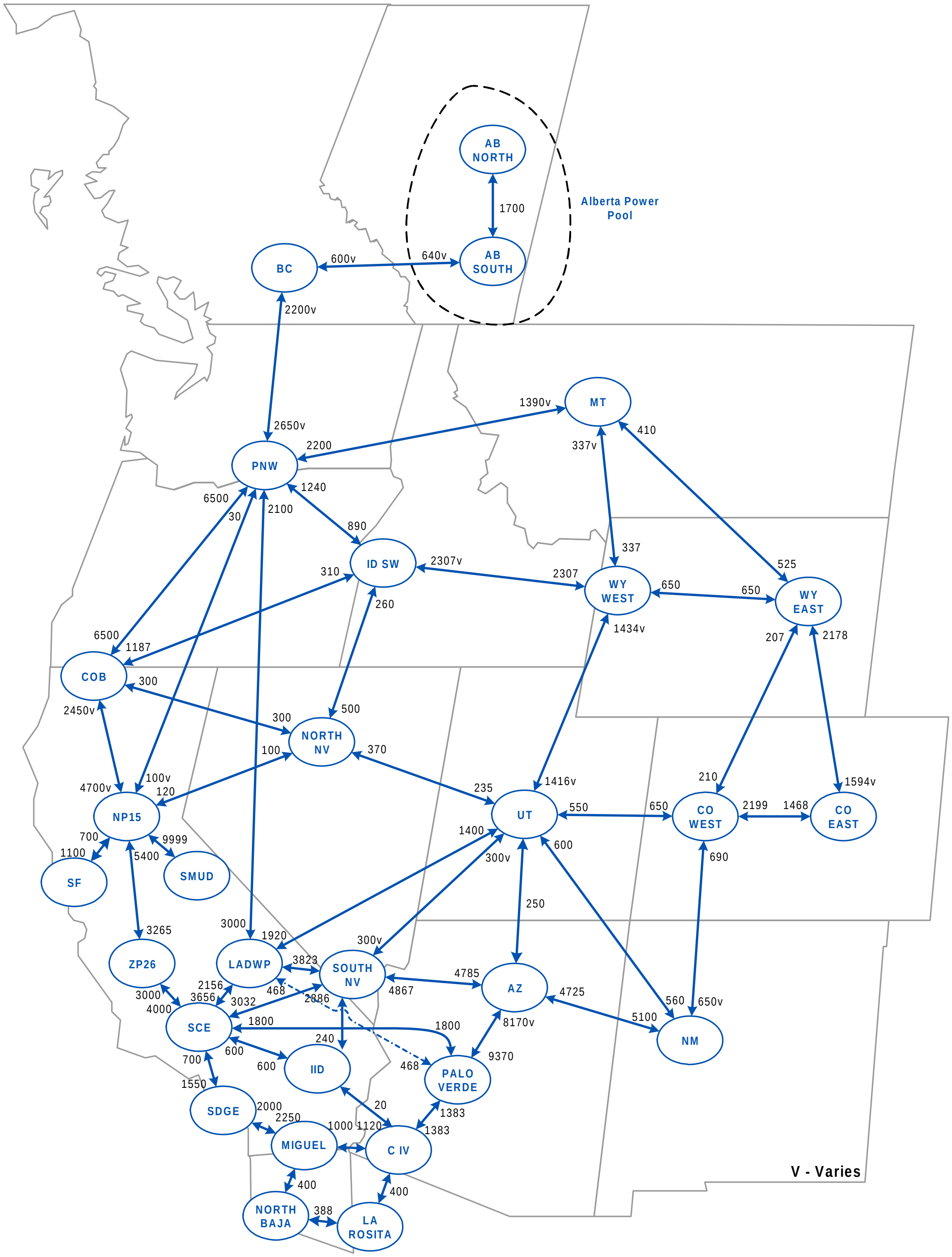
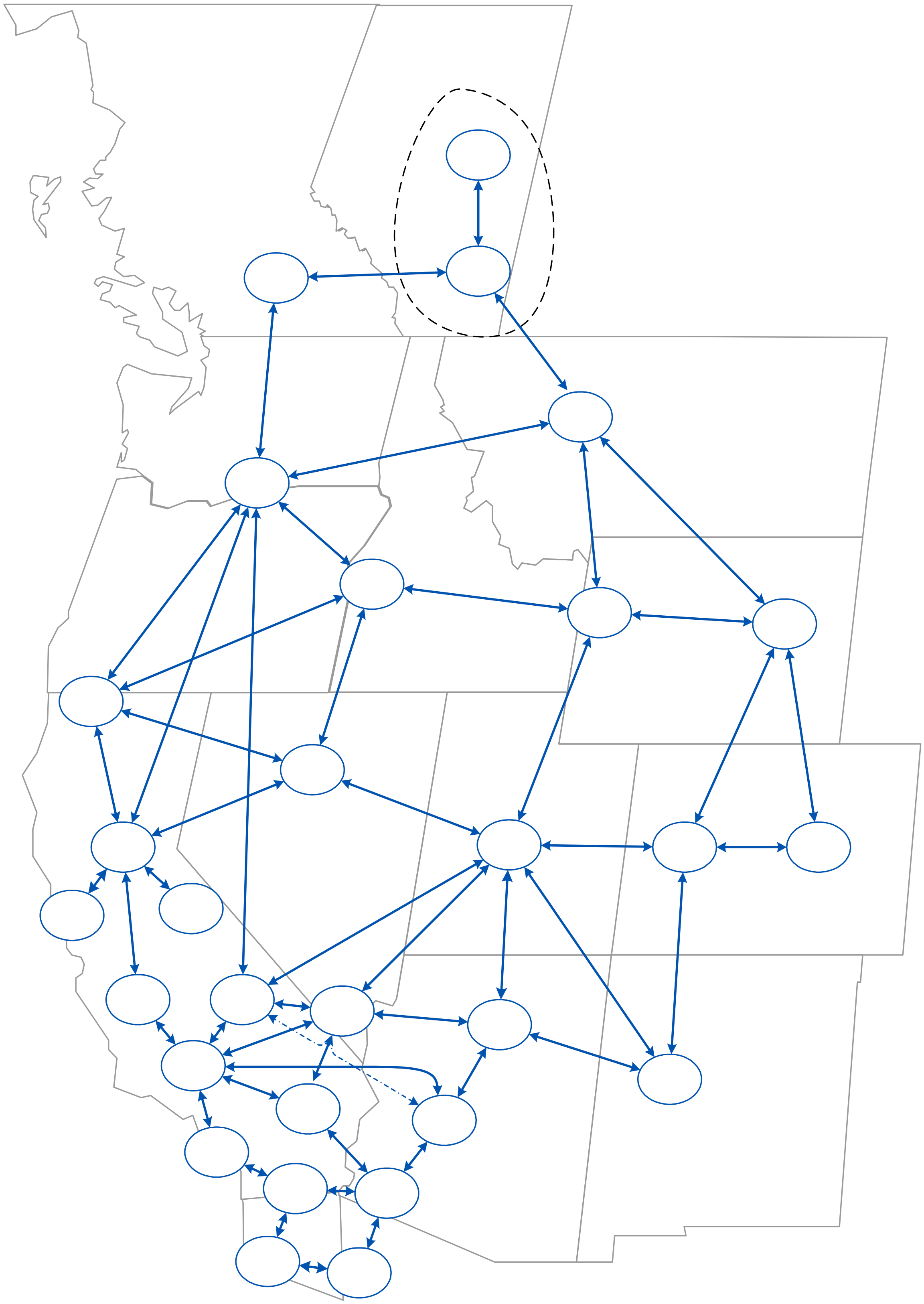


Table A-1: Transmission Path Upgrades 2009-2017

				Transmission Path Expansion (Incremental)			
No.	Trans. Area #1	Trans. Area #2	2008 Path Rating (MW)	Year	Addition #1 (MW)	Year	Addition #2 (MW)
1	BC	AB South	640v	2016	750		
2	South NV	Arizona	4785	2009	1,430		
3	AB South	BC	600v	2009	350	2016	400
4	Northwest	BC	2200v	2009	500		
5	WY West	Idaho	2307	2013	500	2015	200
6	Imperial	IID	120	2013	380		
7	SCE	IID	600	2013	900		
8	Utah	LADWP	1920	2009	480		
9	Northwest	Montana	1390v	2012	310	2014	500
10	BC	Northwest	2650v	2009	500		
11	Montana	Northwest	2200	2011	500	2013	500
12	SCE	Palo Verde	1800	2010	1,200		
13	SF	PG&E	700	2010	800		
14	Arizona	South NV	4867	2009	1,430		
15	IID	SCE	600	2013	900		
16	Palo Verde	SCE	1800	2010	1,200		
17	PG&E	SF	1100	2010	400		
18	AB South	Montana	300	2014	500		
19	Montana	AB South	300	2014	500		

v — indicates that path OTC rating varies seasonally

Figure A-2: WECC 2017 Topology



Simulation Process: Base Case Assumptions for California and Rest of WECC

California Peak and Energy

For this analysis, staff used the 1-in-2 temperature load forecast developed by the Energy Commission DAO. (http://www.energy.ca.gov/2006publications/CEC-400-2006-008/CEC-400-2006-008-SF.PDF) The forecast includes peak demand in megawatts and yearly energy in gigawatt-hours by transmission area for 2008 through 2017.

This peak and energy forecast, updated in 2006, does not include assumptions about the California Solar Initiative or energy efficiency measures beyond 2008. The California Solar Initiative (CSI) was signed into law after staff's previous forecasting cycle. CSI numbers are incorporated into DAO's peak and 2008 draft energy forecast (July 2007). Energy Commission policy is only to include committed (with CPUC approved budgets) energy efficiency programs into DAO's peak and energy forecast. Updated studies on these potential energy efficiency measures will be included in DAO's final peak and energy forecast.

Non-California Peak and Energy

For all areas outside California, staff used the load forecasts provided by GED. These forecasts were developed by GED using publicly available data from EIA and FERC as well as data provided to GED by utilities. Load forecasts include adjustments for conservation and distributed generation. Local load growth patterns and utility load factors are used in projecting future peak demand and yearly energy consumption for non-California utilities.

Fuel Prices

Natural Gas: Staff used the most recent update to western natural gas prices developed by the Energy Commission Natural Gas Unit. The natural gas price forecast includes 31 different pricing points for U.S. portion of the WECC (including 13 for California), two for the Canadian provinces and one price point for Northern Baja, Mexico. Natural gas prices fluctuate monthly for the entire forecast period. California natural gas prices differ by geography, proximity to the pipeline "backbone," and amount used.

Coal: Coal prices in the WECC are assigned to one of two different basins: the Powder River Basin and Rocky Mountain Basin. Fuel prices for each plant are calculated using one of the basin prices (based on proximity and deliverability) and an associated cost adder, also known as transport costs. Coal prices (which fluctuate) are provided monthly through the end of 2008 but are annual prices from 2009 through the end of the forecast.

Fuel Oil: Fuel oil prices for the WECC were updated by GED in the spring of 2007. Fuel oil prices fluctuate monthly throughout the forecast period.

Uranium: GED updated the price forecast for Uranium 308 in the spring of 2007. The price is for an assumed dollar amount per pound U308, based on a long-term supply contract.

WECC Generation Additions-Named and Generic

To supplement the existing resource base, staff made assumptions regarding the addition of new resources in the WECC. These resource additions can be segregated into three different types: high probability named additions, generic renewable additions, and generic thermal additions. These resource types are described below.

High Probability Named Additions

This group of plants includes thermal, hydro, and renewable projects that have moved through the development process and are under construction, or have secured the necessary permits, financing, and have a contract for the plant output. This group of plants may also include projects that have been announced by a utility with a projected resource shortage and have chosen to develop the project on their own. These projects are named, have a specific location for the project, and have secured an interconnection point for the facility to connect to the grid.

Staff reviewed the set of high probability additions in the GED dataset (GED: initial entry) and compared it to the new project data from the Energy Commission Siting Office and new generation database kept by EAO staff. The dataset provided by GED was consistent with data from staff for plant name, unit type, capacity, fuel type, and commercial on-line date, with few exceptions. Some minor edits were made to the data so that it would match Energy Commission data before conducting the final simulation.

Table A2 provides yearly additions by fuel type for this set of new plants. (Note: There are no high-probability named additions added to the base case after 2011.) Please see **Table A-3** at the end of this appendix for the complete list of named additions.

Table A-2: WECC High Probability Named Additions Capacity (MW) Aggregated by Fuel Type*

Fuel Type	2007	2008	2009	2010	2011	Cumulative Total
Biomass		20	85			105
Coal		357	1,150	184	450	2,141
Geothermal	47	276	120			443
Hydro	30	513		49		592
NG	2,205	3,164	1,532	1,280		8,181
Other	12	80				92
Pump Storage		40				40
Solar	64					64
Wind	1,798	706				2,504
Total	4,156	5,156	2,887	1,513	450	14,161

*Additions are not necessarily for California and SB 1368 was not factored in to the capacity additions.

WECC Generic Renewable Additions

A review of the IOU 2006 Long-Term Procurement Plans (public versions) was conducted to obtain each utility's estimate of current levels of RPS eligible energy. In addition, these plans provide an estimate of annual incremental renewable energy (RE) procurement to meet individual IOU annual RE targets. Using this data and information regarding RE projects and proposed transmission projects, staff made assumptions for each IOU regarding how and when each would meet state RPS obligations. The method for setting annual targets differs between the IOUs due to the variation in the filings. DAO load forecasts were used for each IOU in annual RE obligation calculations. A breakdown of each utility's assumed RE obligations and procurement is detailed below.[8]

Southern California Edison: Staff used SCE's best-estimated plan (BEP) as a guide to develop SCE's annual RE resource plan. As a starting point for the RE buildout, staff used SCE's estimates of annual RE for load, expressed as a percentage of retail sales in each year. SCE's RE estimates were "pushed back" one year to reflect staff concerns about the ability of SCE to procure RE given the many uncertainties with RE availability, project performance, and transmission availability. This resulted in SCE reaching the 20 percent RE target in 2012, rather than 2011 as SCE has suggested

[8] *California IOU 2006 Long-Term Procurement Plans: Review of the Treatment of Renewable Energy*, Ryan Wiser, January 3, 2006.

in its BEP. This date is consistent with estimates for transmission expansion in the Tehachapi region to allow for increased penetration of wind energy that is deliverable to SCE load.

The annual percentages of RE were then multiplied by the DAO load forecast to give an annual RE number expressed in GWh. Next, staff used SCE's estimates of RE generation by fuel type for 2007. To accomplish this, staff used the information contained in the pie chart on page 57 of the SCE long-term procurement plan (LTPP). Figure IV-25 provides the mix of renewable energy for SCE's best estimated plan for 2007 and 2016. Staff multiplied the 2007 energy percentages (by fuel type) by the calculated total RE for 2007. This provided an estimate of 2007 RE by fuel type for SCE and was used as the "base year" for the staff RE buildout. Using the 2016 RE estimates found in Figure IV-25, "target" RE percentages (by fuel type) for 2016 were calculated. Using those figures, staff added RE amounts to approximate RE production in 2016 that would approximate SCE's estimate.

It should be noted that staff's simulated annual amounts of RE were considerably lower than SCE estimates from 2008 through 2011 due to the lack of available transmission capacity in staff's simulation model. Significant RE resource additions in 2012 coincide with assumed transmission expansion as well as planned, major RE project additions. This will allow for more RE from wind, biomass, solar, and geothermal resources to help meet RE targets.

Notes and assumptions:

- SCE assumes that no new biomass capacity is added through 2010. As a result, staff did not add biomass to the resource plan until 2011.
- Staff used SCE estimates for annual CSI capacity additions.
- SCE considers transmission capacity and RE project availability as constraints to meeting state RPS mandates.

Pacific Gas and Electric: To develop PG&E's RE buildout, staff used historical qualifying facility (gf) generation data, estimates for renewable energy described in PG&E's basic procurement plan (BPP), and the DAO load forecast. To establish annual RE targets, staff used RE estimates that PG&E assumed would be met in 2007 through 2009 under Scenario 3 of the BPP (~10,500 GWh growing to ~13,000 GWh). Using the DAO load forecast, this amounts to approximately 15 percent RE for retail sales for 2009. While PG&E assumed that it would increase its total renewable percentage from about 15 percent in 2009 to 20 percent in 2011 in the BPP, it also noted that transmission availability and RE resource availability were constraints in achieving its annual targets. For these reasons, staff was more conservative, estimating that PG&E would reach the 20 percent target in 2013.

It should be noted that staff's simulated annual amounts of RE were considerably lower than PG&E RE estimates from 2008 through 2012 due to the lack of available transmission capacity in staff's simulation model. Significant RE resource additions

in 2012 coincide with assumed transmission expansion. This will allow for more RE from wind and solar resources to help PG&E meet RE targets.
Notes and assumptions:

- PG&E did not submit a plan under which the utility would reach 20 percent RE for retail sales by 2010.
- PG&E considers RE availability and transmission availability as constraints to meeting state RPS mandates.
- PG&E states that to meet RE requirements, transmission upgrades will be necessary.
- Staff used PG&E estimates for annual CSI capacity additions.
- Generic renewable capacity additions for PG&E included resources outside PG&E's service territory.

San Diego Gas & Electric: Staff used SDG&E Preferred Plan estimates for existing, planned, and generic RE targets for 2007-2009. Using these estimates, the RE targets climbed from 6 percent in 2007 to 13.8 percent for 2009. Beginning in 2010, staff used lower estimates for RE targets than did SDG&E. In the 2006 filing, SDG&E states that it has approximately 16 percent of RE for retail sales under contract for 2010. Using the DAO load forecast for 2010, staff calculated the amount of RE required to meet the target for 2010, then used a linear approach to SDG&E obtaining 20 percent of RE by 2013 (as opposed to SDG&E reaching 22 percent by 2010 as the IOU claims). Staff's opinion on this RE trajectory is based on the limited availability of in-basin RE, and is consistent with planned transmission expansion projects in Southern California.

It should be noted that staff's simulated annual amounts of RE were considerably lower than SDG&E RE estimates from 2008 through 2012 due to the lack of available transmission capacity in the simulation model. Significant RE resource additions in 2012 coincide with assumed transmission expansion. This will allow for more RE from wind, geothermal, and solar resources to assist SDG&E in meeting RE targets.

Notes and assumptions:

- SDG&E notes that transmission expansion is necessary to meet state RPS mandates.
- Staff used SDG&E estimates for CSI capacity additions.
- Generic renewable capacity additions for SDG&E included resources outside of SDG&E service territory.

For California POUs, it was assumed they would work toward a RPS target of 10 percent RE for retail sales by 2013. This estimate is based on staff's review of current level of renewable production from POUs and POU RE projects in development and announced in media reports. While POUs are not required by state law to provide customers with a specific percentage of energy from renewable sources, larger POUs (Los Angeles Department of Water & Power, Sacramento Municipal Utility District, Imperial Irrigation District) have set their own RE goals. Staff considers the estimate of 10 percent by 2013 to be in line with POU RE projections, if not slightly conservative.

Data obtained from the Energy Commission Renewable Office staff estimated that 6.5 percent of 2006 POU delivered energy came from eligible renewable technologies (approximately 4,700 GWh). For staff's base case, this amount of generation was assumed to continue throughout the forecast, and additional RE was added by staff to meet a 10 percent target by 2013. POU RE projects that are announced and in development were added, along with assumed generic renewable additions. Capacity additions included wind projects, geothermal, biomass, and solar resources. Assumed generic renewable resource additions for POUs were not necessarily located in each POU service area due to the limited RE potential in those areas.

A spreadsheet database was created to track renewable energy production, individual state renewable energy requirements, and generic renewable additions throughout the forecast period. For those state's with RPS requirements, yearly loads (in GWh) for the utilities subject to each states RPS were aggregated. Information on which states have RPS and a summary of the standards were acquired from the Database of State Incentives for Renewables and Efficiency (DSIRE) website (http://www.dsireusa.org). Annual renewable production was then calculated from the simulation results using eligible technologies for each state, and any multipliers or credits were factored into the total renewable energy production for each state (for example: 1.5 kWh credit for in-state production of 1 kWh produced from solar technology). Yearly renewable targets for each state were compared to yearly production to determine if new renewable resources would need to be added to meet state mandates. In those states where production fell significantly short of the target, generic renewable resources were added to the base case.

For those states with a RPS requirement in place, EAO staff added renewable energy to the mix of resources for each state, before adding generic, non-renewable resources into staff's base case.

Out of state RE additions were based on a review of each state's potential for renewable energy technologies, as outlined in the *Renewable Energy Atlas of the West*, published in July 2002. The atlas was produced and written by the Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, and the GreenInfo Network. The atlas was used as a guide for evaluating the potential for renewable energy production from biomass, geothermal, solar, and wind resources. Estimates for annual energy production from each resource type by state are provided in the atlas. Staff used these estimates when adding generic renewable resources to the base case, considering existing transmission and proximity to load centers when making the additions.

Figures A-3 and A-4 below illustrate where generic renewable capacity, and the associated energy production from these units, was added by state or province.

Figure A-3: Installed Renewable Capacity by State and Province, 2017

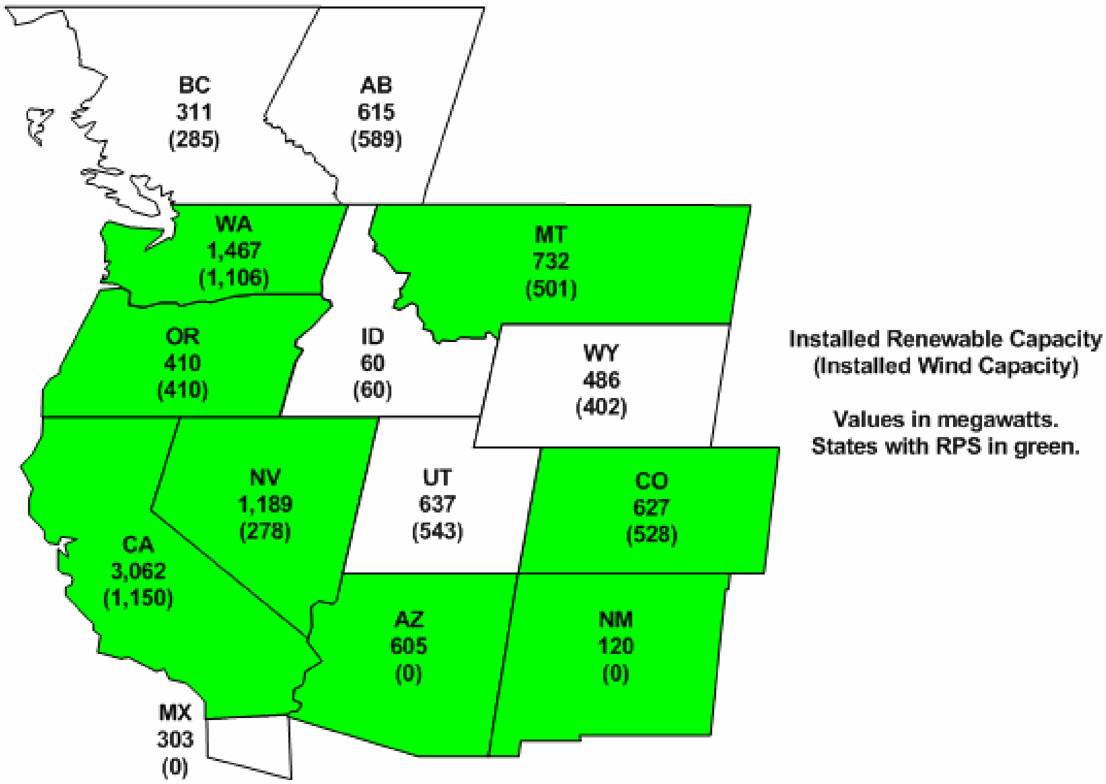
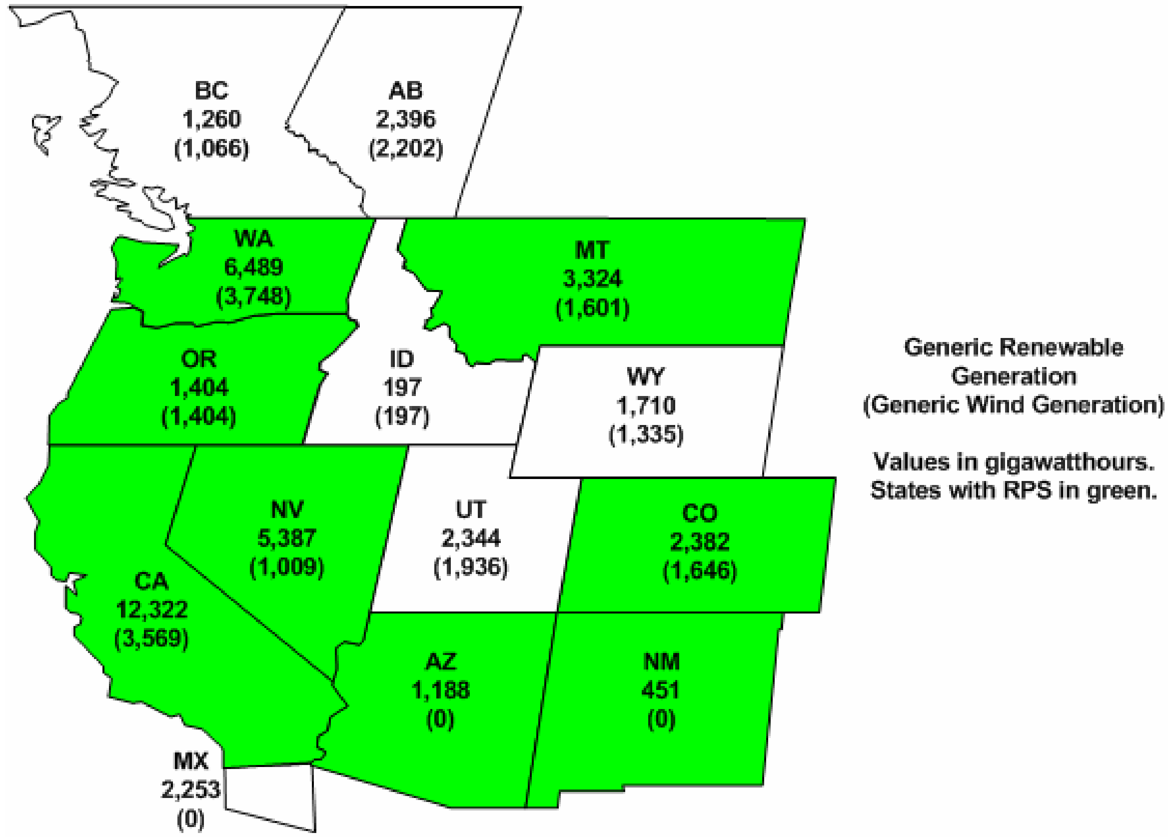


Figure A-4: Expected Generic Renewable Generation, 2017 GWh



Generic Generation Additions

After adding generic renewable resources to the base case, staff reviewed data for peak demand and available dependable capacity at the control area level. Using a 15 percent reserve margin as a target, staff added generic thermal resources to the base case in each area where needed.

The generic resource characterizations added to the base case were developed by GED for use in the MarketSym model. The four types of generic thermal plants used were; a 500 MW pulverized coal plant, a 490 MW natural gas combined-cycle plant, a 100 MW aero-derivative gas turbine, and a 180 MW gas turbine. **Table A-4** below provides an overview for each plant type.

Table A-4: Generic Thermal Power Plant Specifications*

Unit Characteristics	Units	Generator Type			
		Aero derivative Gas Turbine	Gas Turbine	Combined Cycle	Pulverized Coal
Date of Initial Entry	Year	2008	2008	2017	2011
Summer Capacity	MW	90	160	450	500
Winter Capacity	MW	100	180	490	500
Full Load Heat Rate	HHV, Btu/kWh	8,668	10,500	6,500	9,300
Forced Outage Rate	%	3.60%	3.60%	5.50%	6.00%
Maintenance Outage Rate	%	4.10%	4.10%	4.10%	6.50%

*Source: Global Energy Decisions

Arizona and California were given the most generic thermal capacity, nearly all of it fueled by natural gas. Other areas receiving significant generic additions were Alberta, British Columbia, and Utah. For a complete list of the generic resource additions, please see **Table A-5** at the end of this appendix.

Generation Retirements

For this study, staff used retirement dates for generating units as determined by GED, with few exceptions. GED uses different assumptions for generation retirements based on the type and size of the unit in question. In general, renewable resources are not retired. When a renewable resource is known to have specific retirement date, GED assumes that it will be replaced by a similar type and size facility. For nuclear power plants, life expectancy is assumed to last through the end of the plant's operating permit issued by the NRC, usually 40 years for the original license and 20 years for subsequent extensions. Large coal plants (>300 MW) are assumed to have a life expectancy of 75 years, while smaller coal plants are given a 55 year operational lifespan. The 55-year lifespan for coal units of 300 MW or less is used for all other thermal plants, also. This is based on a "high level" survey conducted by GED that found very few of these types of units operate, or planned to operate, longer than 55 years. **Table A-6** below provides the assumed annual retirements, by fuel type, for the forecast period.

Table A-6: Assumed Annual Capacity Retirements (MW)

Year	Coal	Fuel Oil	NG	Annual Total
2007		231	511	742
2008		75	338	413
2009		180	742	922
2010	293		190	483
2011			279	279
2012			554	554
2013	10		990	1,000
2014	19		770	790
2015			858	858
2016	48	10	896	954
2017	10	32	1,149	1,191
Total by Fuel Type	381	528	7,276	8,185

Source: California Energy Commission Staff, 2007

Natural Gas Fuel Use for Electric Generation

Based on these supply, demand, and transmission assumptions, **Table A-7**, below, provides EAO's forecast of natural gas demand for electric generation for California and the entire WECC region. This forecast is based on an average water year, average temperature conditions and load forecast, and current trends in RPS and other power generation legislative mandates throughout the WECC.

Table A-7: Natural Gas Demand for Electric Generation (GBtu)

Year	Rest of WECC	CA	Total WECC
2008	895,143	855,998	1,751,141
2009	909,405	880,718	1,790,124
2010	969,825	899,150	1,868,974
2011	903,426	884,229	1,787,655
2012	962,872	914,716	1,877,588
2013	990,137	900,512	1,890,650
2014	1,053,603	911,567	1,965,170
2015	1,105,592	936,829	2,042,421
2016	1,139,012	969,060	2,108,072
2017	1,192,064	970,129	2,162,193

Source: California Energy Commission Staff, 2007

Table A-3: High Probability Named Additions

Unit Name	Unit No.	Area	Unit Type	Capacity (MW)	Year	Fuel Type
Enmax Taber Wind Pro		AB	WT	80	2007	Wind
OPTI/Nexen Long Lake	1	AB	CGGT	85	2007	NG
OPTI/Nexen Long Lake	2	AB	CGGT	85	2007	NG
Steel Park Wind	15	AZ	WT	15	2007	Wind
_150 Mile House ERG	ST	BC	ST	5.9	2007	Other
Bone Creek		BC	HY	20	2007	Hydro
Clemina Creek		BC	HY	10	2007	Hydro
Mount Hays Wind Farm	14	BC	WT	25.2	2007	Wind
Savona ERG Project	ST	BC	ST	5.9	2007	Other
GenGTA_CSCE07 LB	1	CA	GenGT	100	2007	NG
GenGTA_CSCE07 LB	2	CA	GenGT	100	2007	NG
GenGTA_CSCE07 LB	3	CA	GenGT	50	2007	NG
Pine Tree Wind		CA	WT	120	2007	Wind
Roseville Energy	1a	CA	CC	87.5	2007	NG
Roseville Energy	1b	CA	CC	87.5	2007	NG
Windstar I	60	CA	WT	120	2007	Wind
Cedar Creek Wind Ene	200	CO	WT	300	2007	Wind
Peetz Wind (FPL)	133	CO	WT	199.5	2007	Wind
Spindle Hill	GT1	CO	GT	157	2007	NG
Spindle Hill	GT2	CO	GT	157	2007	NG
Twin Buttes Wind Far	50	CO	WT	75	2007	Wind
Burley Butte Wind Pa	17	ID	WT	10.5	2007	Wind
Lava Beds Wind		ID	WT	18	2007	Wind
Milner Dam Wind		ID	WT	18	2007	Wind
Notch Butte Wind		ID	WT	18	2007	Wind
Oregon Trail Wind Pa		ID	WT	10.5	2007	Wind
Pilgrim Stage Statio		ID	WT	10.5	2007	Wind
Raft River Geothermal		ID	GE	10	2007	Geothermal
Salmon Falls Wind		ID	WT	21	2007	Wind
Schwendiman Wind	18	ID	WT	20	2007	Wind
Thousand Springs Win	1-7	ID	WT	10.5	2007	Wind
Tuana Gulch Wind Par		ID	WT	10.5	2007	Wind
Afton CC	1	NM	CC	272	2007	NG
Nevada Solar One		NV	SS	64	2007	Solar
Salt Wells Geothermal	GE1	NV	GE	11	2007	Geothermal
Stillwater II	GE1	NV	GE	26	2007	Geothermal
Biglow Canyon	63	OR	WT	450	2007	Wind
Elkhorn Wind Power P	70	OR	WT	66	2007	Wind
Port Westward	1	OR	CC	400	2007	NG
Desert Power CC	1	UT	CC	45	2007	NG
Desert Power CC	2	UT	CC	45	2007	NG

Unit Name	Unit No.	Area	Unit Type	Capacity (MW)	Year	Fuel Type
Lake Side	1a	UT	CC	267	2007	NG
Lake Side	1b	UT	CC	267	2007	NG
White Creek Wind Pro	87	WA	WT	200	2007	Wind
Snowflake White Moun	ST	AZ	ST	20	2008	Biomass
Yuma Peaker	GT2	AZ	GT	50	2008	NG
Yuma Peaker	GT1	AZ	GT	50	2008	NG
Anyox River Hydroele		BC	HY	30	2008	Hydro
Bear Mountain Wind	60	BC	WT	120	2008	Wind
Dokie Wind Energy Pr	100	BC	WT	180	2008	Wind
East Toba River		BC	HY	120	2008	Hydro
Forrest Kerr		BC	HY	112	2008	Hydro
Glacier Creek		BC	HY	40	2008	Hydro
Gold River Power Pro	ST2	BC	ST	40	2008	Other
Gold River Power Pro	ST1	BC	ST	35	2008	Other
Howser Creek		BC	HY	49.6	2008	Hydro
Kitsault River Hydro		BC	HY	26.5	2008	Hydro
Kookipi Creek		BC	HY	10	2008	Hydro
Kwoiek Creek		BC	HY	50	2008	Hydro
Log Creek		BC	HY	10	2008	Hydro
Montrose Creek		BC	HY	50	2008	Hydro
Princeton Power Proj	ST1	BC	ST	49	2008	Coal
Rainy River Hydro		BC	HY	15	2008	Hydro
Humboldt Bay	C6	CA	IC	16.3	2008	NG
Humboldt Bay	C2	CA	IC	16.3	2008	NG
Humboldt Bay	C3	CA	IC	16.3	2008	NG
Humboldt Bay	C1	CA	IC	16.3	2008	NG
Humboldt Bay	C10	CA	IC	16.3	2008	NG
Humboldt Bay	C4	CA	IC	16.3	2008	NG
Humboldt Bay	C7	CA	IC	16.3	2008	NG
Humboldt Bay	C8	CA	IC	16.3	2008	NG
Humboldt Bay	C9	CA	IC	16.3	2008	NG
Humboldt Bay	C5	CA	IC	16.3	2008	NG
Inland Empire Energy	1	CA	CS	405	2008	NG
Inland Empire Energy	2	CA	CS	405	2008	NG
Niland	GT1	CA	GT	46.5	2008	NG
Niland	GT2	CA	GT	46.5	2008	NG
Olivenhain Hodges Pumped Storage	1	CA	PS	40	2008	Pump storage
Pacific Wind	WT	CA	WT	205.5	2008	Wind
Panoche Energy Cente	GT2	CA	GT	100	2008	NG
Panoche Energy Cente	GT1	CA	GT	100	2008	NG
Panoche Energy Cente	GT3	CA	GT	100	2008	NG
Panoche Energy Cente	GT4	CA	GT	100	2008	NG

Unit Name	Unit No.	Area	Unit Type	Capacity (MW)	Year	Fuel Type
Salton Sea #6		CA	GE	215	2008	Geothermal
SFERP Potrero 1		CA	GT	49	2008	NG
SFERP Potrero 2		CA	GT	49	2008	NG
SFERP Potrero 3		CA	GT	49	2008	NG
Lamar Plant	AB	CO	AB	18	2008	Coal
Mountain Home	3	ID	GT	170	2008	NG
Raft River Geothermal	E2	ID	GE	26	2008	Geothermal
Hobbs	1a	NM	CC	288	2008	NG
Hobbs	1b	NM	CC	288	2008	NG
Reeves	CC	NM	CC	206	2008	NG
Ely Wind	1	NV	WT	200	2008	Wind
Galena 2		NV	GE	10	2008	Geothermal
Galena 3	GE	NV	GE	25	2008	Geothermal
Tracy (NV)	1a	NV	CCDF	249.5	2008	NG
Tracy (NV)	1b	NV	CCDF	249.5	2008	NG
TS Power Plant	1	NV	ST	200	2008	Coal
Sumas Recovered Ener	ST	WA	ST	5	2008	Other
Wygen II	1	WY	ST	90	2008	Coal
Springerville	4	AZ	ST	400	2009	Coal
Mackenzie Green Ener	ST	BC	CGST	50	2009	Biomass
Contra Costa Power	8a	CA	CCDF	235	2009	NG
Contra Costa Power	8b	CA	CCDF	235	2009	NG
Eastshore Energy Fac	IC	CA	IC	116	2009	NG
EIF Bullard	GT	CA	GT	196	2009	NG
El Centro CC	3	CA	CC	120	2009	NG
Otay Mesa	1a	CA	CCDF	255	2009	NG
Otay Mesa	1b	CA	CCDF	255	2009	NG
Starwood Power Fireb	GT	CA	GT	120	2009	NG
Comanche (CO)	3	CO	ST	750	2009	Coal
Torrance County Biom	ST1	NM	ST	35	2009	Biomass
Blue Mountain Geothe	GE	NV	GE	30	2009	Geothermal
Buffalo Valley	ST	NV	GE	30	2009	Geothermal
Carson Lake	ST	NV	GE	30	2009	Geothermal
Newberry Volcano	GE1	OR	GE	30	2009	Geothermal
Songhees Creek Hydro		BC	HY	15	2010	Hydro
Upper Stave Creek		BC	HY	33.6	2010	Hydro
Wapiti Energy	ST1	BC	ST	184	2010	Coal
PG&E Colusa County	1A	CA	CC	330	2010	NG
PG&E Colusa County	1B	CA	CC	330	2010	NG
Russell City	CC	CA	CC	620	2010	NG
Keephills	3	AB	ST	450	2011	Coal

Source: CEC/Global Energy Decisions

Table A-5: Generic Thermal Resource Additions

Unit Name	Unit No.	Unit Type	Max Rating	Year	Fuel Type	Area
GenGT_AB_S08	4	GenGT	180	2008	NG	AB
GenGTA_CSCE08 Pkrs	1	GenGT	100	2008	NG	CA
GenGTA_CSCE08 Pkrs	2	GenGT	100	2008	NG	CA
GenGTA_CSCE08 Pkrs	3	GenGT	50	2008	NG	CA
GenGT_NBAJ09	1	GenGT	180	2009	NG	BCN
GenGT_NBAJ09	2	GenGT	180	2009	NG	BCN
GenGT__Ariz10	1	GenGT	180	2010	NG	AZ
GenGT__Ariz10	2	GenGT	180	2010	NG	AZ
GenGT__Ariz10	3	GenGT	180	2010	NG	AZ
GenGT_AB_S10	1	GenGT	180	2010	NG	AB
GenGT_AB_S10	2	GenGT	180	2010	NG	AB
GenGT_ABCN10	1	GenGT	180	2010	NG	AB
GenGT_ABCN10	2	GenGT	180	2010	NG	AB
GenGT__Ariz11	1	GenGT	180	2011	NG	AZ
GenGT__Ariz11	2	GenGT	180	2011	NG	AZ
GenGT__Ariz11	3	GenGT	180	2011	NG	AZ
GenGT__Ariz11	4	GenGT	180	2011	NG	AZ
GenGT_ABCN11	1	GenGT	180	2011	NG	AB
GenGT_BC11	1	GenGT	180	2011	NG	BC
GenGT_BC11	2	GenGT	180	2011	NG	BC
GenGT_BC11	3	GenGT	180	2011	NG	BC
GenGT_NBAJ11	1	GenGT	180	2011	NG	BCN
GenST_AB_S11	1	GenCoal	500	2011	Coal	AB
GenST_AZ11	1	GenCoal	500	2011	Coal	AZ
GenST_SNEV11	1	GenCoal	500	2011	Coal	NV
GenST_WYCE11	1	GenCoal	300	2011	Coal	WY
GenGT__Ariz12	1	GenGT	180	2012	NG	AZ
GenGT_CO E12	1	GenGT	180	2012	NG	CO
GenGT_NewM12	1	GenGT	180	2012	NG	NM
GenGT_PV23	1	GenGT	180	2012	NG	AZ
GenGT_PV23	2	GenGT	180	2012	NG	AZ
GenGT_PV23	3	GenGT	180	2013	NG	AZ
GenGT_PV23	4	GenGT	180	2013	NG	AZ
GenGT_PV28	1	GenGT	180	2013	NG	AZ
GenGT__Ariz14	1	GenGT	180	2014	NG	AZ
GenGT__Ariz14	2	GenGT	180	2014	NG	AZ
GenGT__Ariz14	3	GenGT	180	2014	NG	AZ
GenGT_AB_S14	1	GenGT	180	2014	NG	AB
GenGT_Ariz14	1	GenGT	180	2014	NG	AZ
GenGT_Ariz14	2	GenGT	180	2014	NG	AZ
GenGT_Ariz14	3	GenGT	180	2014	NG	AZ

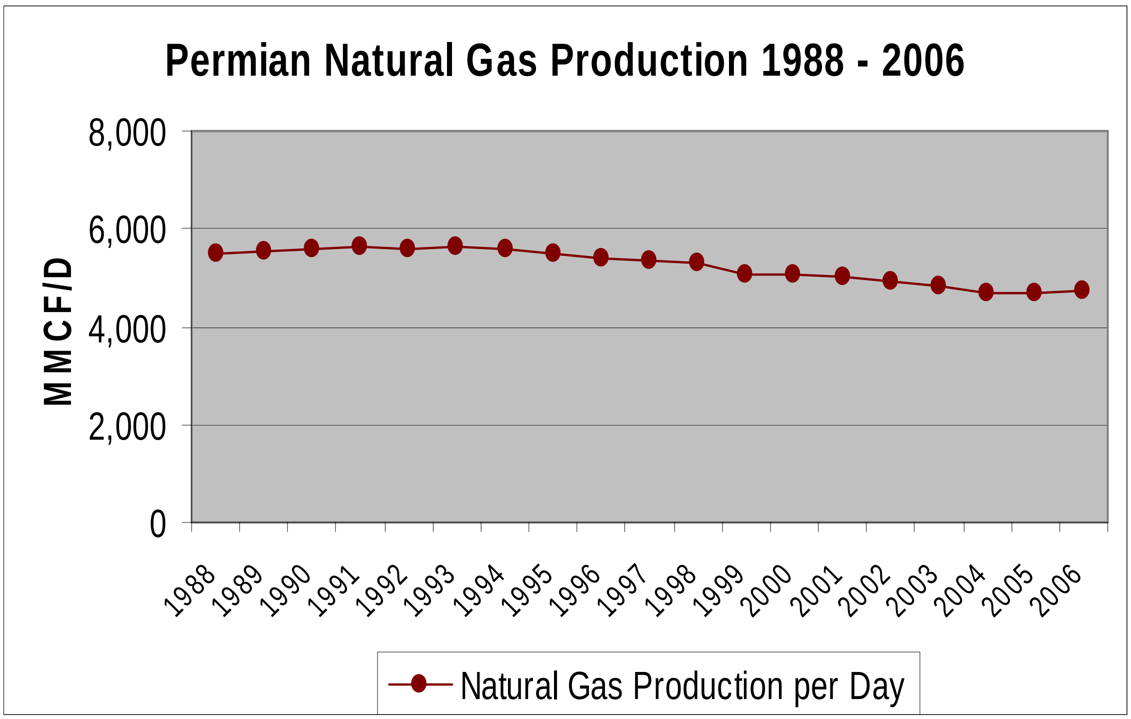
Unit Name	Unit No.	Unit Type	Max Rating	Year	Fuel Type	Area
GenGT_Ariz14	4	GenGT	180	2014	NG	AZ
GenGT_CO E14	1	GenGT	180	2014	NG	CO
GenGT_CO E14	2	GenGT	180	2014	NG	CO
GenGT_ID_S14	1	GenGT	180	2014	NG	ID
GenGT_Utah14	1	GenGT	180	2014	NG	UT
GenGT_Utah14	2	GenGT	180	2014	NG	UT
GenGT_Utah14	3	GenGT	180	2014	NG	UT
GenGTA_CSDG14	1	GenGT	100	2014	NG	CA
GenGTA_CSDG14	2	GenGT	100	2014	NG	CA
GenGTA_LADW14	1	GenGT	100	2014	NG	CA
GenGTA_LADW14	2	GenGT	100	2014	NG	CA
GenGTA_LADW14	3	GenGT	100	2014	NG	CA
GenGTA_LADW14	4	GenGT	100	2014	NG	CA
GenGTA_LADW14	5	GenGT	100	2014	NG	CA
GenGTA_LADW14	6	GenGT	100	2014	NG	CA
GenGTA_LADW14	7	GenGT	100	2014	NG	CA
GenGTA_LADW14	8	GenGT	100	2014	NG	CA
GenGT__Ariz15	1	GenGT	180	2015	NG	AZ
GenGT__Ariz15	2	GenGT	180	2015	NG	AZ
GenGT_CO E15	1	GenGT	180	2015	NG	CO
GenGT_CO E15	2	GenGT	180	2015	NG	CO
GenGT_NBAJ15	1	GenGT	180	2015	NG	BCN
GenGT_NBAJ15	2	GenGT	180	2015	NG	BCN
GenGT_NewM15	1	GenGT	180	2015	NG	NM
GenGT_Nort15	1	GenGT	180	2015	NG	WA
GenGT_Nort15	2	GenGT	180	2015	NG	WA
GenGT_Utah15	1	GenGT	180	2015	NG	UT
GenGT_Utah15	2	GenGT	180	2015	NG	UT
GenGT_Utah15	3	GenGT	180	2015	NG	UT
GenGT_Utah15	4	GenGT	180	2015	NG	UT
GenGTA_CNP115	1	GenGT	100	2015	NG	CA
GenGTA_CNP115	2	GenGT	100	2015	NG	CA
GenGTA_CSDG15	1	GenGT	100	2015	NG	CA
GenGTA_CSDG15	2	GenGT	100	2015	NG	CA
GenGTA_CSDG15	3	GenGT	100	2015	NG	CA
GenGTA_CSDG15	4	GenGT	100	2015	NG	CA
GenGTA_CSDG15	5	GenGT	100	2015	NG	CA
GenGTA_CSDG15	6	GenGT	100	2015	NG	CA
GenGTA_CSDG15	7	GenGT	100	2015	NG	CA
GenGTA_CSDG15	8	GenGT	100	2015	NG	CA
GenGTA_CSDG15	9	GenGT	100	2015	NG	CA
GenGTA_IID15	1	GenGT	100	2015	NG	CA
GenGTA_IID15	2	GenGT	100	2015	NG	CA
GenGTA_LADW15	1	GenGT	100	2015	NG	CA

Unit Name	Unit No.	Unit Type	Max Rating	Year	Fuel Type	Area
GenGTA_LADW15	2	GenGT	100	2015	NG	CA
GenST_UT15	1	GenCoal	500	2015	Coal	UT
GenGT__Ariz16	1	GenGT	180	2016	NG	AZ
GenGT__Ariz16	2	GenGT	180	2016	NG	AZ
GenGT__Ariz16	3	GenGT	180	2016	NG	AZ
GenGT_AB_S16	1	GenGT	180	2016	NG	AB
GenGT_AB_S16	2	GenGT	180	2016	NG	AB
GenGT_Ariz16	1	GenGT	180	2016	NG	AZ
GenGT_Ariz16	2	GenGT	180	2016	NG	AZ
GenGT_Ariz16	3	GenGT	180	2016	NG	AZ
GenGT_ID_S16	1	GenGT	180	2016	NG	ID
GenGT_IDE_S16	1	GenGT	180	2016	NG	ID
GenGT_NBAJ16	1	GenGT	180	2016	NG	BCN
GenGT_Utah16	1	GenGT	180	2016	NG	UT
GenGTA_CSCE16	1	GenGT	100	2016	NG	CA
GenGTA_CSDG16	1	GenGT	100	2016	NG	CA
GenGTA_CSDG16	2	GenGT	100	2016	NG	CA
GenGTA_CSDG16	3	GenGT	100	2016	NG	CA
GenGTA_CSDG16	4	GenGT	100	2016	NG	CA
GenGTA_CSDG16	5	GenGT	100	2016	NG	CA
GenGTA_IID16	1	GenGT	100	2016	NG	CA
GenGTA_IID16	2	GenGT	100	2016	NG	CA
GenGTA_LADW16	1	GenGT	100	2016	NG	CA
GenGTA_LADW16	2	GenGT	100	2016	NG	CA
GenST_AZ16	1	GenCoal	500	2016	Coal	AZ
GenCCY_AB_S17	1	GenCC	245	2017	NG	AB
GenGT__Ariz17	1	GenGT	180	2017	NG	AZ
GenGT__Ariz17	2	GenGT	180	2017	NG	AZ
GenGT__Ariz17	3	GenGT	180	2017	NG	AZ
GenGT__Ariz17	4	GenGT	180	2017	NG	AZ
GenGT_ID_S17	1	GenGT	180	2017	NG	ID
GenGT_MT17	1	GenGT	180	2017	NG	MT
GenGT_NBAJ17	1	GenGT	180	2017	NG	BCN
GenGT_SNev17	1	GenGT	180	2017	NG	NV
GenGT_SNev17	2	GenGT	180	2017	NG	NV
GenGT_SNev17	3	GenGT	180	2017	NG	NV
GenGTA_CNP117	1	GenGT	100	2017	NG	CA
GenGTA_CNP117	2	GenGT	100	2017	NG	CA
GenGTA_CSDG17	1	GenGT	100	2017	NG	CA
GenGTA_CSDG17	2	GenGT	100	2017	NG	CA
GenGTA_CSDG17	3	GenGT	100	2017	NG	CA
GenGTA_CSDG17	4	GenGT	100	2017	NG	CA
GenST_COE17	1	GenCoal	500	2017	Coal	CO

APPENDIX B: PRODUCTION RECORDS

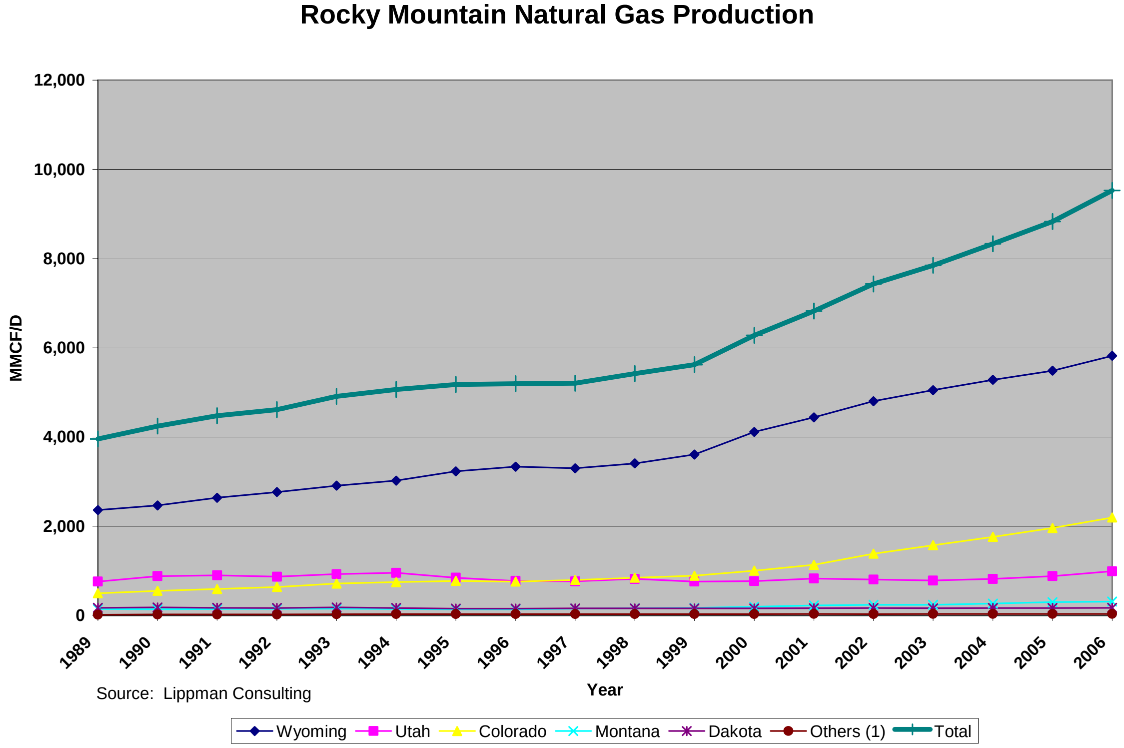
Figures B-1 through **B-5** are the most recent production records for the major producing areas important to California. These include the Permian Basin, the various producing areas of the Rocky Mountains, the San Juan Basin, California, and the Western Canadian Sedimentary Basin (WCSB), in Canada. As shown, only production in the Rocky Mountains is increasing, and the remaining areas have flat to declining production trends.

Figure B-1



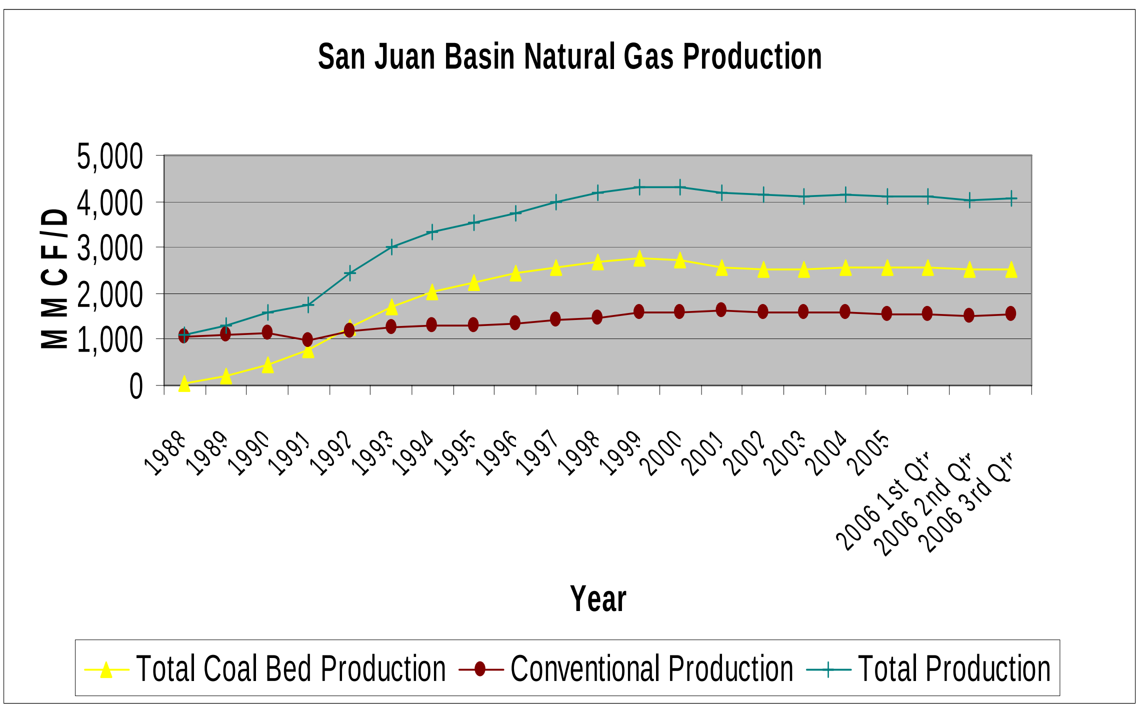
Source: Lippman Consulting

Figure B-2



Source: Lippman Consulting

Figure B-3



Source: Lippman Consulting

Figure B-4

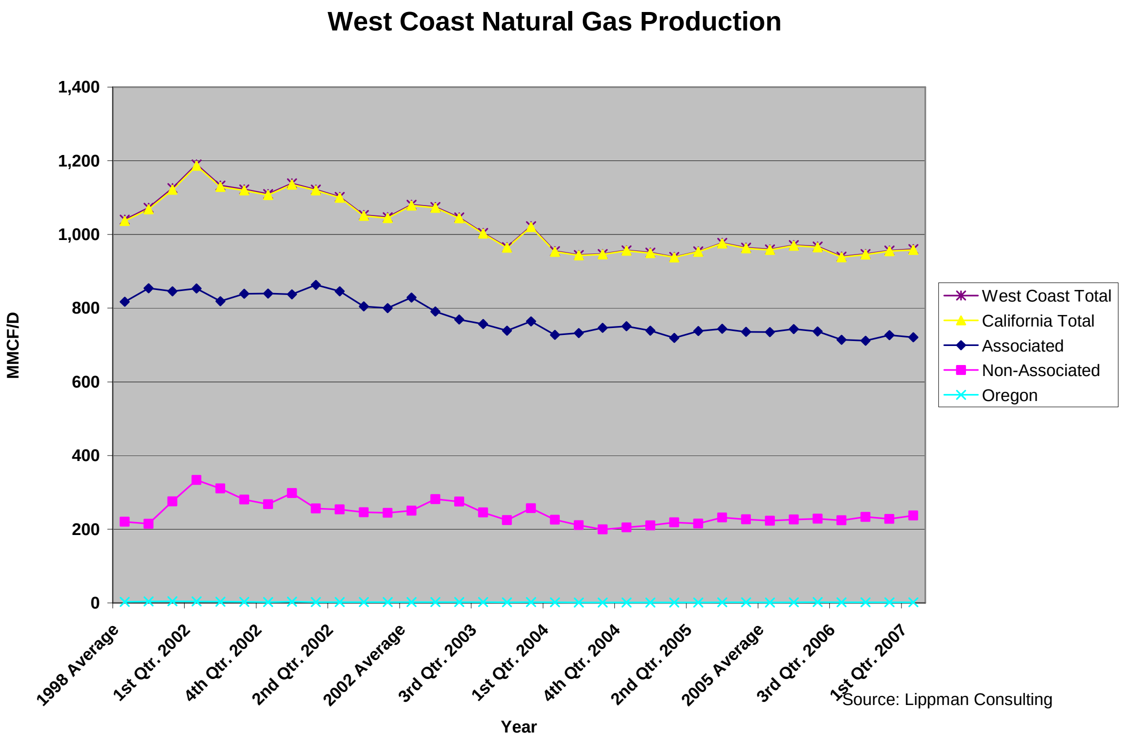
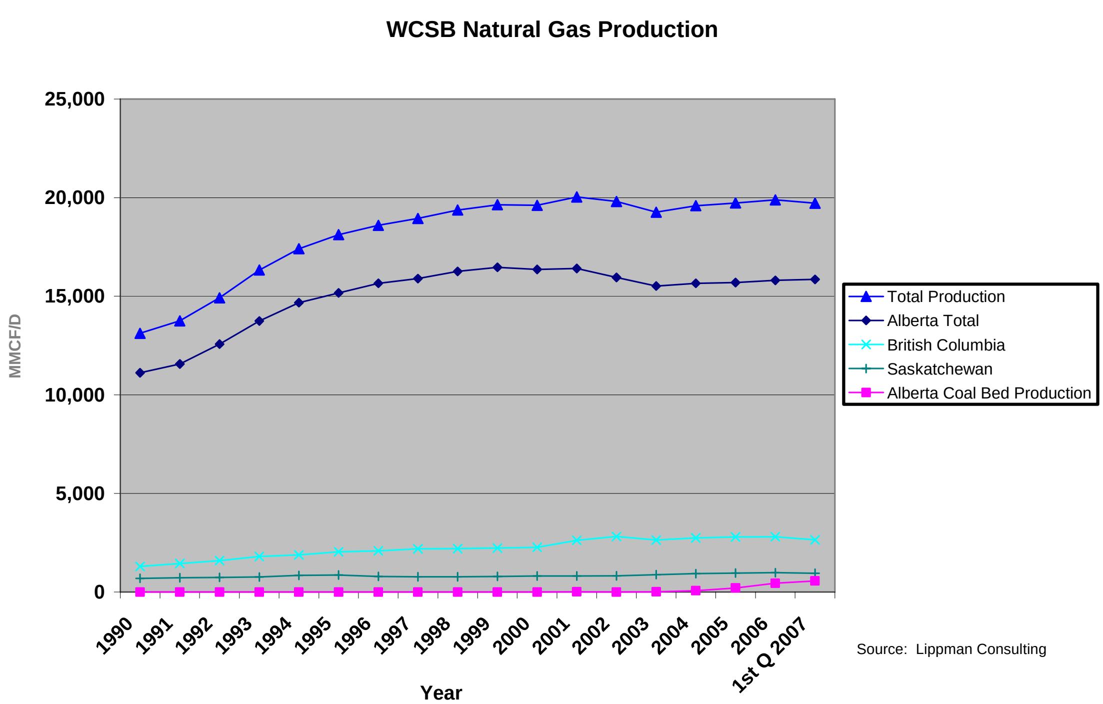
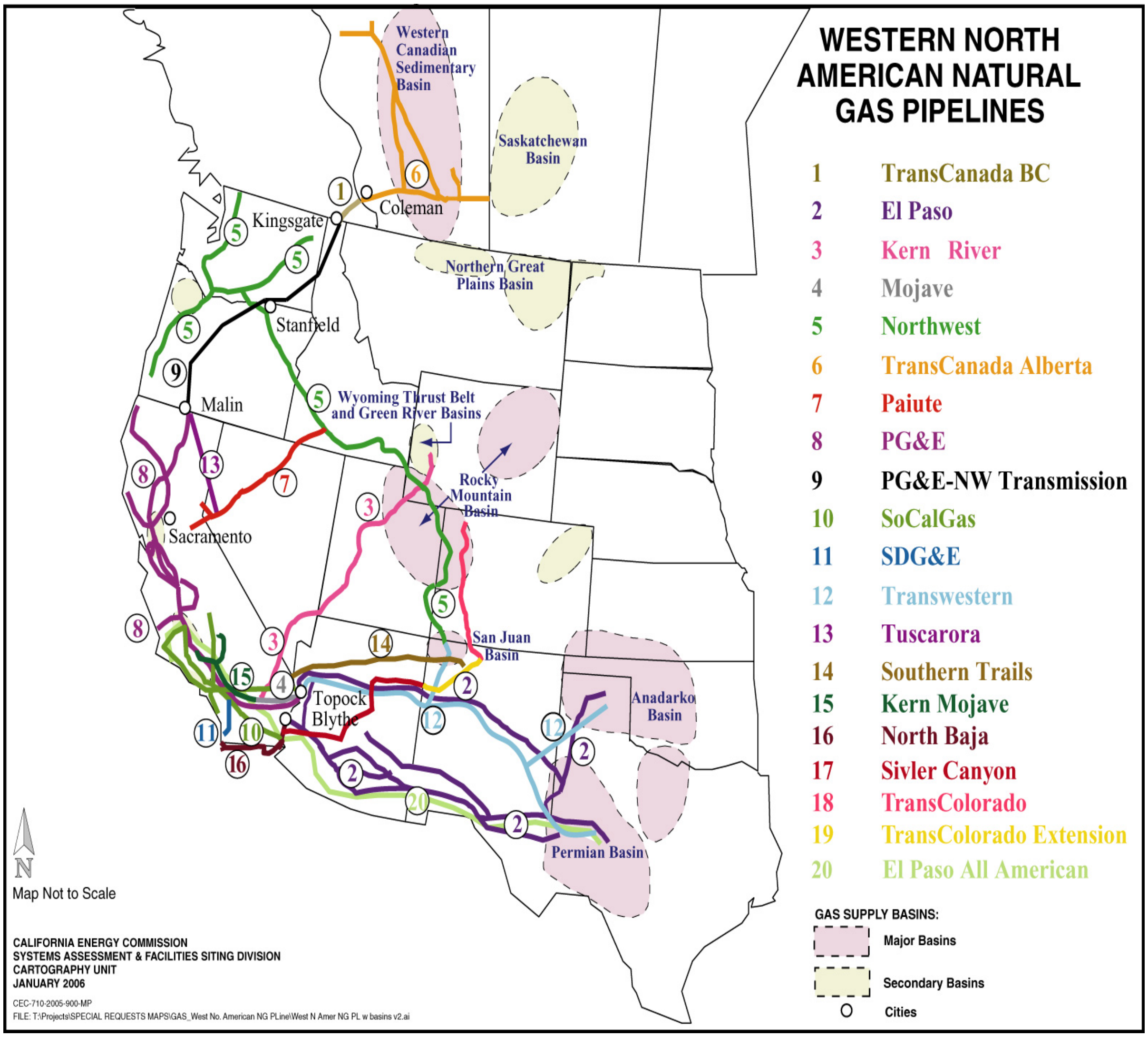


Figure B-5



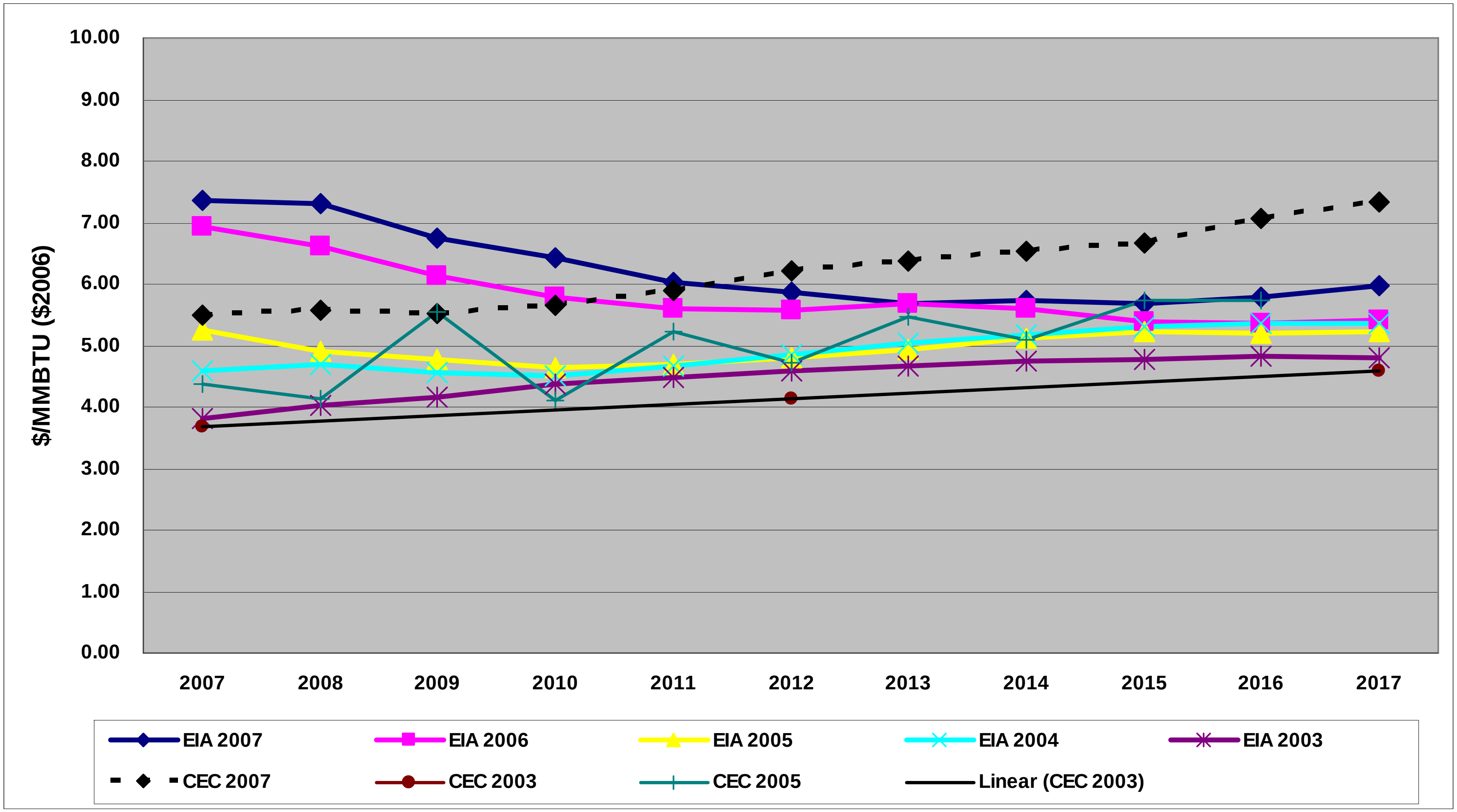
APPENDIX C: PIPELINES SERVING CALIFORNIA

Figure C-1: Pipelines Serving California



APPENDIX D: HISTORICAL PRICE FORECASTS

Figure D-1: Historical Price Forecasts



Source: California Energy Commission Staff, 2007

APPENDIX E: SENSITIVITIES

This *2007 Final Natural Gas Market Assessment* expands the analysis of the natural gas system by simulating four sensitivities. Each sensitivity starts with the revised base case, changes specific model input parameter or parameters, and examines the impact on natural gas prices and supplies. A brief description of the four sensitivities follows:

Sensitivity I: Increase the natural gas demand for power generation to simulate dry hydro conditions. Although California's most significant one-year historic drought occurred in 1977, staff used monthly hydroelectric data from each plant in the Western Electricity Coordinating Council (WECC) from 1982 to 2002 to develop adverse hydro energy conditions. This period contains the largest dry period (1988-1992) of data historically available. As a result of this sensitivity, power generation demand in the WECC increased between 12 and 14 percent for each year between 2008 and 2017.

Sensitivity 2: Insert a 1 Bcf per day liquefied natural gas (LNG) regasification terminal in Southern California, operation beginning in 2011.

Sensitivity 3: Insert a 1 Bcf per day LNG regasification terminal in Southern California, operation beginning in 2011, and allows a 1 Bcf per day expansion in 2015.

Sensitivity 4: Insert a 1 Bcf per day LNG regasification terminal in Southern California, operation beginning in 2011, and insert a 1 Bcf per day LNG regasification terminal in the Pacific Northwest, operation beginning in 2015.[9]

In all LNG sensitivities, staff assumes a usage rate of 75 percent.

Major Findings

The major findings of the World Gas Trade/ North American Regional Model (WGTM/NARG) sensitivity runs follow:

- Increasing the WECC power generation demand adds upward pressure on ($2006) prices. By the end of the forecast horizon, prices rise by about $0.15 to $0.20/Mcf.

- LNG flows from regasification terminals in Southern California and in the Pacific Northwest displace California's traditional sources of natural gas supplies.

[9] Sensitivity 4 required a minor structural change. In the base case, the LNG terminal in the Pacific Northwest, though turned off, links to markets in the Pacific Northwest before flowing to Malin. This case, however, creates a direct link to the Malin Hub. As a result, LNG supplies compete with Canadian supplies at Malin.

- In all three LNG cases, the insertion of LNG regasification terminals produces price reductions that, in most years of the forecast horizon, vary between $0.15/Mcf and $0.60/Mcf.

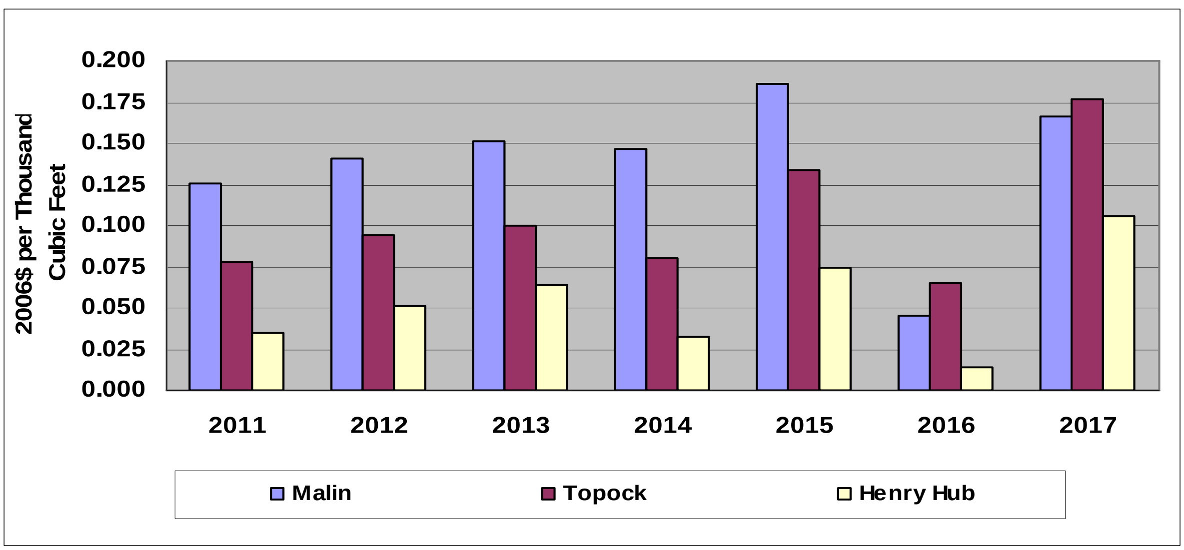
Results of Sensitivity Cases

The results examine the impact of the changes to the reference base case. In the charts and tables below, a difference means the following: Sensitivity of Interest minus reference base case

Sensitivity 1: Dry Hydro

Dry hydro conditions increase demand for natural gas used in the power generation sector, pushing demand higher by approximately 12 percent. As a result, prices increase by about $0.15/Mcf at Malin and $0.12 to $0.18/Mcf at Topock. Henry Hub produced smaller increases, never exceeding $0.12/Mcf during the forecast horizon. **Figure E-1** illustrates the price differences.

Figure E-1: Price Differences in Sensitivity 1



Source: California Energy Commission Staff, 2007

Supplies available to California increase to meet the demand requirements for the power generation sector and natural gas supplies from Southwest and Canada satisfy the added demand. At same time, California production and Mexican LNG flows experience small reductions. **Table E-1** displays the flows difference for 2011, 2014, and 2017.

Table E-1: Flow Differences in Sensitivity 1, MMcf/D

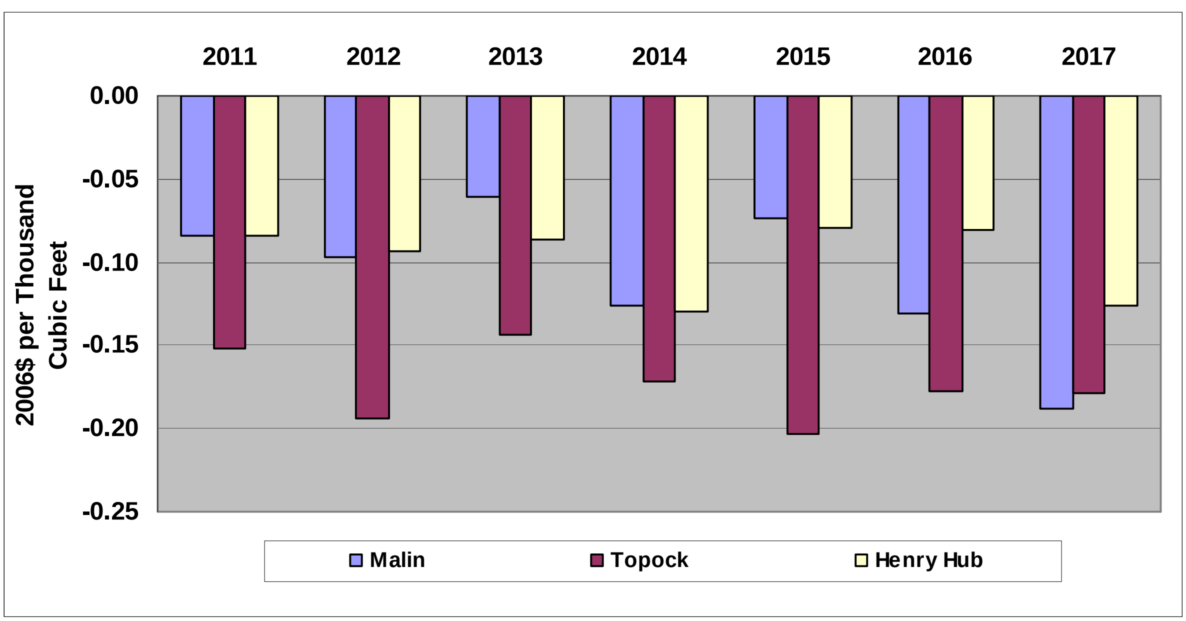
Flows Difference compared with the Basecase			
	2011	2014	2017
California Production	(39.1)	(36.1)	(33.6)
Southwest	138.6	138.9	275.3
Canada	194.1	216.3	72.3
Rockies	14.1	3.4	(0.1)
Mexico (LNG)	(19.5)	(8.6)	(13.0)

Source: California Energy Commission Staff, 2007; ( ) means negative

Sensitivity 2: An LNG Regasification Terminal (1 Bcf/D) in Southern California with no Expansion in Later years

The addition of a 1 Bcf/D regasification terminal in Southern California intensifies gas-on-gas competition throughout the state, placing downward pressure on prices after operation begins. Between 2011 and 2017, prices fall as much as $0.20/Mcf at Topock. Other hubs experiences smaller price reduction. **Figure E-2** demonstrates the price reduction.

Figure E-2: Price Differences in Sensitivity 2



Source: California Energy Commission Staff, 2007

Also, LNG flows from the terminal displaces natural gas supplies from traditional sources. Southwest drops almost 600 MMcf/D, Rocky Mountains supplies fall over 100 MMcf/D, and, by the end of the forecast horizon, Canada flows to California lessen by 100 MMcf/D. **Table E-2** displays the flows difference for 2011, 2014, and 2017.

Table E-2: Flow Differences in Sensitivity 2, MMcf/D

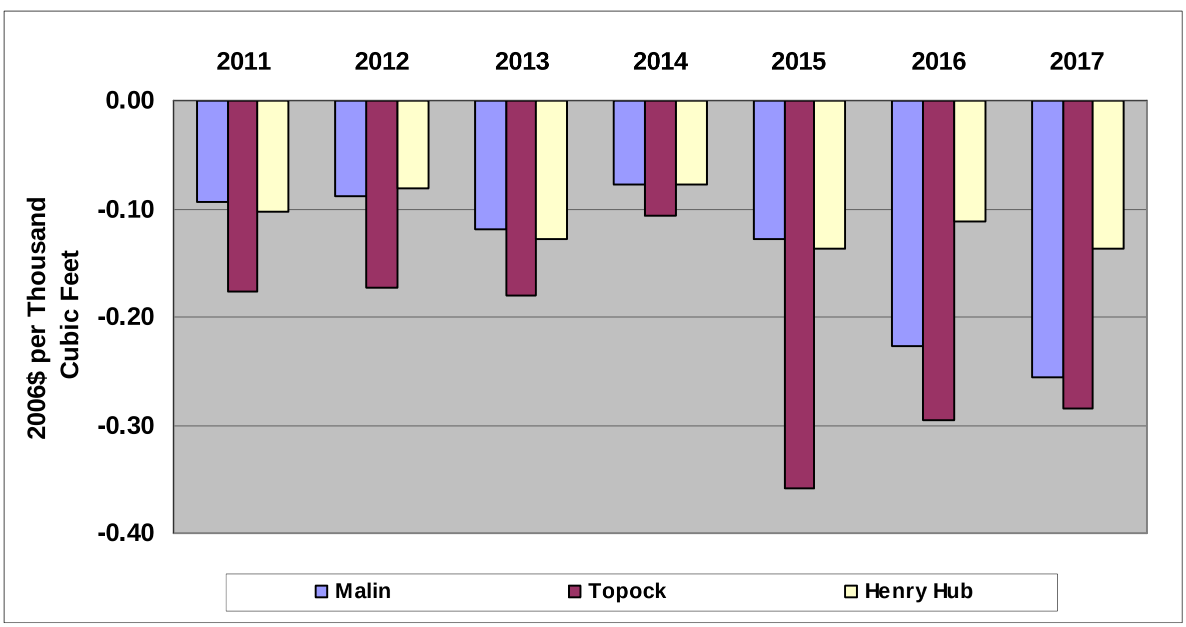
Flows Difference compared with the Basecase			
	2011	2014	2017
California Production	(45.8)	(41.5)	(36.5)
Southwest	(594.5)	(565.3)	(571.2)
Canada	(0.8)	(3.7)	(100.5)
Rockies	(159.4)	(196.0)	(81.1)
Mexico	0.0	0.0	(0.0)
Southern California LNG	749.3	749.3	749.3

Source: California Energy Commission Staff, 2007; ( ) means negative

Sensitivity 3: An LNG Regasification Terminal (1 Bcf/D) in Southern California with Expansion in Later Years

Expansion the Southern California LNG regasification terminal pushes prices even lower. By the end of the forecast horizon, the price reduction nears and, in some years, exceeds $0.30/Mcf**. Figure E-3** illustrates the price reduction between 2011 and 2017. **Table E-3** shows that all traditional sources of natural gas supplies lose market share, with the Southwest experiencing the largest reduction.

Figure E-3: Price Differences in Sensitivity 3



Source: California Energy Commission Staff, 2007

Table E-3: Flow Differences in Sensitivity 3, MMcf/D

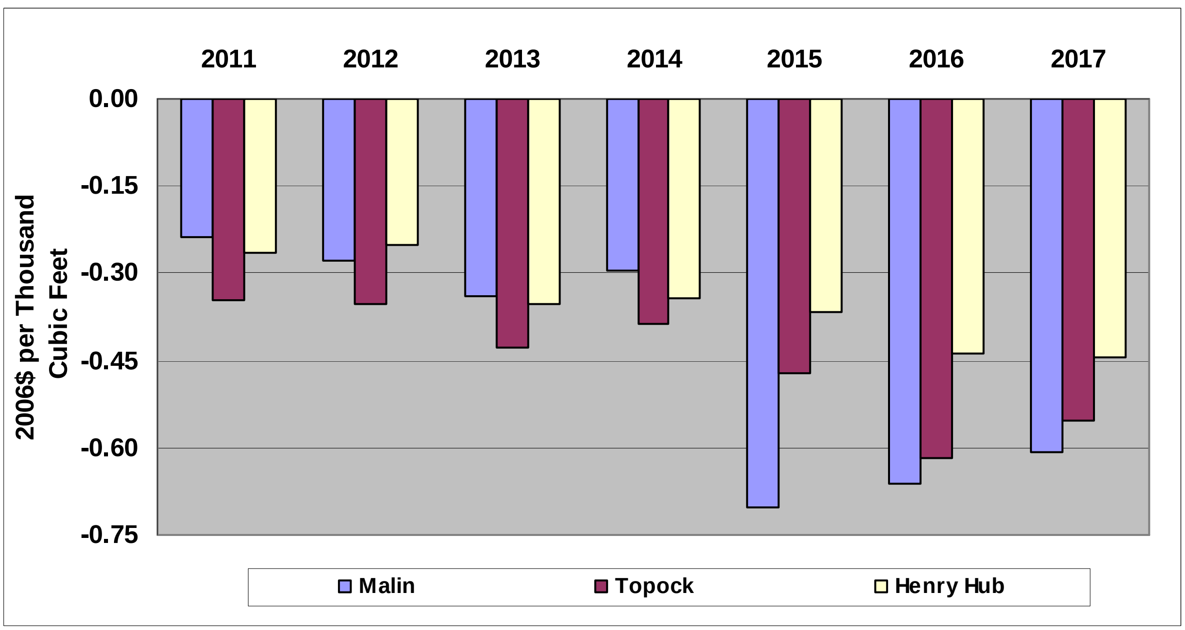
Flows Difference compared with the Basecase			
	2011	2014	2017
California Production	(44.5)	(49.0)	(52.9)
Southwest	(607.8)	(497.2)	(1024.4)
Canada	0.0	(1.2)	(219.7)
Rockies	(145.9)	(251.9)	(228.0)
Mexico	0.0	0.0	(0.0)
Southern California LNG	749.3	749.3	1498.5

Source: California Energy Commission Staff, 2006; ( ) means negative

Sensitivity 4: An LNG Regasification Terminal (1 Bcf/D) in Southern California with an 1 Bcf/D Terminal in the Pacific Northwest

Sensitivity 4 (1 Bcf/D in Southern California and 1 Bcd/D in the Pacific Northwest) generates the largest price reduction. Gas-on-gas competition intensifies at two important California hubs: Malin (Oregon) in the north and Topock in the south. This competition pushes natural gas prices lower, with prices falling by as much as $0.70/Mcf. **Figure E-4** shows the price reduction. All traditional sources, except Canada, lose market share. At beginning, Canada experiences a reduction in flows, but, by the end of the forecast horizon, it gains market share relative to the Southwest and the Rockies.

Figure E-4: Price Differences in Sensitivity 4



Source: California Energy Commission Staff, 2007

Table E-4 demonstrates the flow changes in supplies available to California. In this sensitivity, staff can't estimate how much LNG enters from the north since Canadian supplies and LNG commingles at Malin.

In this sensitivity, the expansion of Line 300, indicated by the reference base case, still occurs in 2016. However, the magnitude of the expansion shrinks to about 130 MMcf/D. The added flow of LNG relieves some of the pressure to expand Line 300.

Table E-4: Flow Differences in Sensitivity 4, MMcf/D

Flows Difference compared with the Basecase			
	2011	2014	2017
California Production	(46.0)	(43.5)	(41.9)
Southwest	(618.3)	(564.5)	(923.4)
Canada	(11.4)	(19.6)	375.5
Rockies	(192.0)	(270.5)	(295.7)
Mexico	0.0	0.2	(0.1)
Southern California LNG	749.3	749.3	749.3

Source California Energy Commission Staff, 2007; ( ) means negative

APPENDIX F: THE WORLD GAS TRADE MODEL: BRIEF DESCRIPTION

The World Gas Trade Model (WGTM)

In the *2007 Final Natural Gas Market Assessment*, the Energy Commission staff used the World Gas Trade Model, a generalized equilibrium model that calculates long-term market clearing prices and quantities, production and pipeline flows. However, to accommodate the model's functions and simulate the natural gas market, staff disaggregated the model at four levels:

a. Super-regions
b. Regions
c. Sub-regions
d. Activity nodes

Super-Regions

The super-regions represent the highest level of disaggregation within the WGTM. The model contains two types of super-regions:

a. *Geographic*: Africa, Australia, Europe, Latin America, Mainland Asia, Middle East, North America, Pacific Rim, and Russia;

b. *Process*: World LNG Liquefaction, World LNG Regasification, World Shipping, and World Oil.

The super-region North America represents the North American Regional Gas (NARG) model.

Regions and Sub-Regions

The WGTM divides each super-region into smaller units called regions. For example, the North American super-region contains three regions: United States, Canada, and Mexico. The regions then break into sub-regions. For example, the United States contains three main sub-regions types:

a. *Supply*: 40 supply sub-regions (supply basins)
b. *Demand*: 54 demand sub-regions (demand centers)
c. *Transportation*: 33 transportation sub-regions (pipeline and pipeline corridors)

Activity Nodes

Every sub-region within the WGTM further subdivides into activity nodes. Staff updates and inputs model data at this level. The model uses fives types of activity nodes:

a. *Supply resource*: These nodes contain the supply cost curves and determine how much natural gas a resource produces and at what cost.

b. *Allocation*: These nodes determine the allocation of natural gas. The models calculate direction of flow and the price of flow quantities in these nodes. Unlike other activity nodes, allocation nodes do not allow the inputting of data.

c. *Processing*: These nodes represent natural gas gathering facilities, or LNG liquefaction facilities, or LNG regasification facilities.

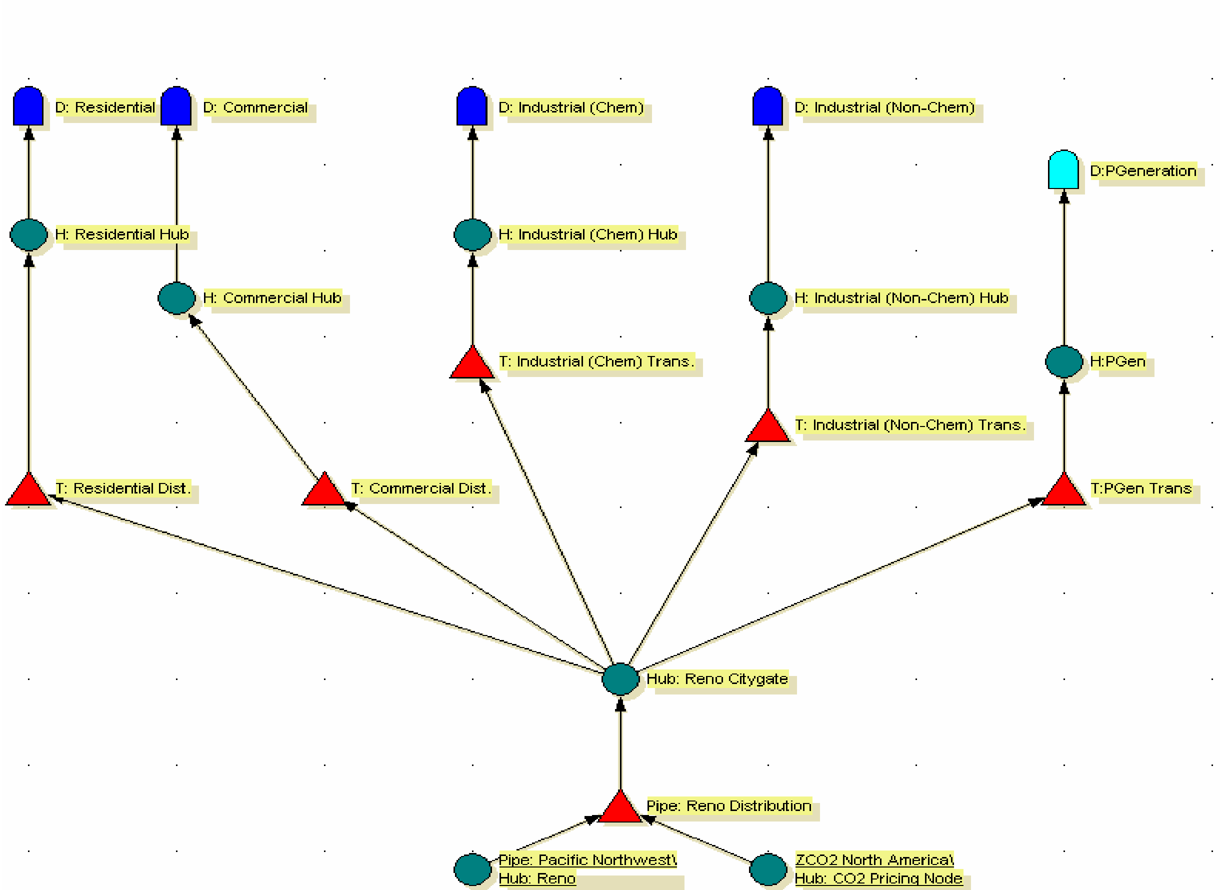
d. *Transportation*: These nodes link supply basins to demand centers and also link LNG liquefaction to LNG regasification. These nodes represent either a pipeline or a pipeline corridor (a series of pipelines transporting natural gas in the same general direction). Also, the model uses these nodes to simulate the movement of LNG in cargo tankers (shipping lanes).

e. *Demand*: These nodes represent all demand sectors including residential, commercial, industrial, and power generation. These nodes can represent elastic demand (residential, commercial, and industrial) or inelastic demand (power generation).

Figure F-1, in this case, illustrates a typical sub-region—a demand sub-region. The tombstones represent demand sectors, the circles represent allocations, and the triangles represent transportation along pipeline or pipeline corridor.

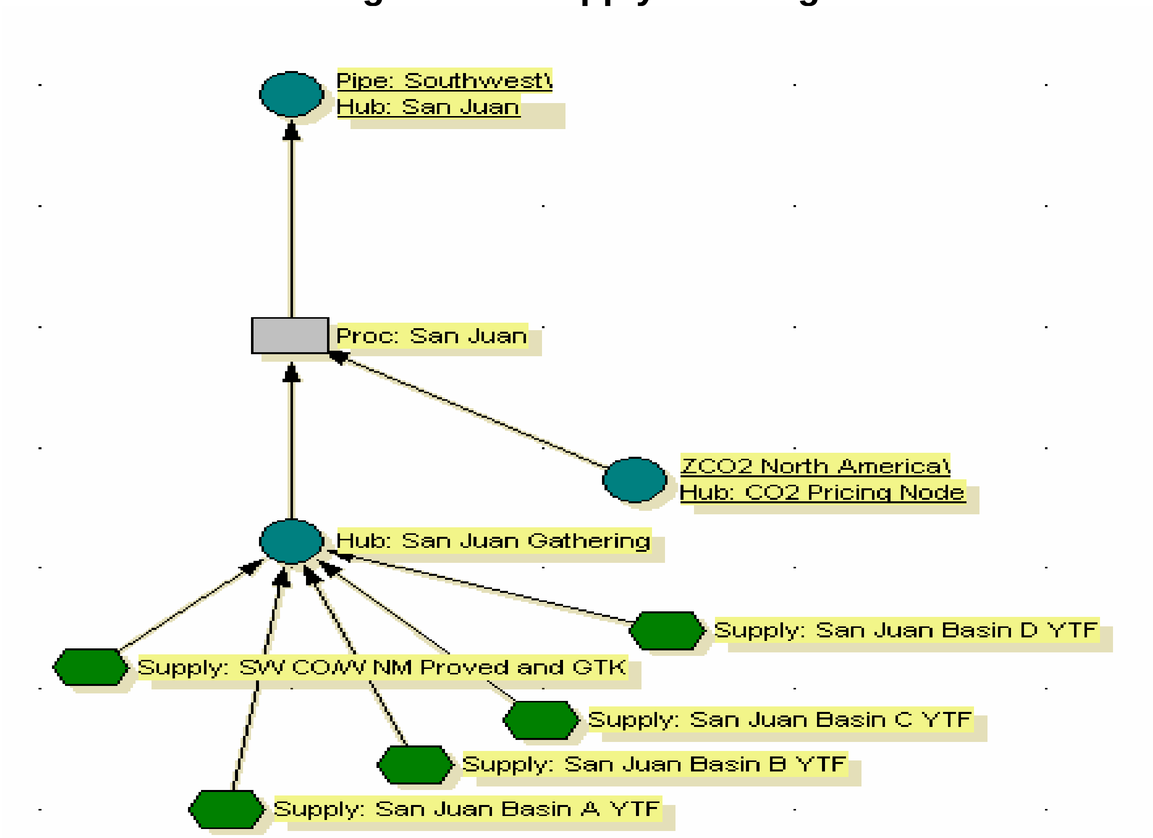
Figure F-2 illustrates a supply sub-region. The hexagons represent different supply resources. The model contains a supply cost curve for each supply resource. Over 200 supply cost curves, used to determine the marginal cost of production of natural gas, reside within the model. The rectangle represents a natural gas gathering facility.

Figure F-1: Demand Sub-Region



Source: California Energy Commission Staff

Figure F-2: Supply Sub-Region



Source: California Energy Commission Staff

Model's Features

In the current version of the model, staff broke out the time periods as follows: One-year periods between 2006 and 2020, two-year periods between 2020 and 2038, and five-year periods between 2038 and 2048.

The level of detail in the WGTM has evolved over time. As new information becomes available, the Commission staff updates various parameters that include the natural gas resource base, pipeline infrastructure (additional or abandonment), and the makeup of end-user demand. A major feature of the model is its flexibility, which allows a user to add or delete pipelines and to modify supply and demand sub-regions. Further, the user can adjust the model at a specific time during the forecast period. The model's flexibility allows for the adjustment of available supply, required demand, or needed pipeline capacity.

In 2003, the National Petroleum Council (NPC) completed a comprehensive study of the natural gas resource base on the North American continent. In 2006, Altos Management Partners updated the NPC work, and staff incorporated the new supply cost curves in the current version of the WGTM. The model contains all known natural gas resources and all associated cost of production. Resources fall into two reserve categories: proven and potential. Proven reserves require only operation and maintenance (O&M) expenditure for production. However, potential reserves require expenditure of both capital and O&M costs. In addition, the model contains representation to account for other competing fuels such as oil and for the trading of LNG in the world.

The competitive functions of the WGTM model evaluate the cost of the development of all potential resources against the cost of other natural gas sources, production from other supply regions in the United States, Canada, and imports of LNG. Based upon the relative costs and elasticities, the model decides how much of each resource enters the supply mix.

In addition, the transportation nodes—pipelines or pipeline corridors—link supply regions to demand regions and link LNG liquefaction to LNG regasification. For each transportation node, staff develops a profile, which includes pipeline capacity, transportation rates (tariff), and expansion criteria. As such, the model is a representation of a competitive natural gas market that simulates the integrated world trading system. The WGTM configures each transportation corridor (pipeline, pipeline corridor, or shipping lane) by designating a transport capacity and cost that can vary with use and/or new pipeline infrastructure. Further, when economically feasible, the model will add capacity to an existing corridor. For example, the model applies an associated cost to the transportation tariff to account for expenditure of expanding the pipeline capacity when natural gas flows exceed the listed capacity.

APPENDIX G: FORECASTED NATURAL GAS DEMAND

Table G-1: Forecasted Natural Gas Demand for North America (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
United States Lower 48	58,781	59,574	60,935	62,415	64,604	67,164	67,864	68,778	69,935	70,982	72,112
Canada	8,980	9,307	9,667	10,067	10,453	10,801	11,150	11,293	11,362	11,423	11,504
Mexico	3,897	4,010	4,272	4,653	4,892	5,081	5,279	5,466	5,692	5,885	6,105
Total	71,658	72,891	74,874	77,134	79949	83,046	84,294	85,537	86,989	88,290	89,721

United States Tables

Table G-2: Forecasted Natural Gas Demand for United States (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Core	31,946	32,142	32,589	32,946	33,075	33,152	33,130	33,117	33,337	33,472	33,689
Non-Core	10,545	10,610	10,866	11,055	10,983	10,878	10,640	10,403	10,363	10,271	10,223
Power Generation	16,290	16,823	17,479	18,414	20,547	23,134	24,094	25,258	26,235	27,240	28,200
Total	58,781	59,574	60,935	62,415	64,604	67,164	67,864	68,778	69,935	70,982	72,112

Table G-3: Forecasted United States Natural Gas Demand by Regions (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
East North Central	10,048	10,168	10,386	10,566	10,799	11,016	11,114	11,213	11,360	11,475	11,651
East South Central	2,983	3,056	3,224	3,381	3,585	3,785	3,903	4,023	4,177	4,320	4,492
Middle Atlantic	7,679	7,812	7,935	8,044	8,432	8,812	8,924	9,035	9,203	9,354	9,554
Mountains	4,207	4,335	4,377	4,506	4,431	4,576	4,691	4,843	4,987	5,009	5,029
New England	2,584	2,608	2,644	2,689	2,837	2,991	2,979	2,966	2,986	3,003	3,023
Pacific	7,303	7,606	7,645	7,862	7,791	7,944	7,929	8,093	8,144	8,331	8,407
South Atlantic	6,963	6,958	7,256	7,542	8,264	8,978	9,314	9,649	9,861	10,059	10,341
West North Central	3,427	3,465	3,533	3,585	3,785	3,978	3,969	3,961	4,048	4,124	4,151
West South Central	13,588	13,566	13,935	14,241	14,679	15,085	15,040	14,995	15,169	15,307	15,465
Total	58,781	59,574	60,935	62,415	64,604	67,164	67,864	68,778	69,935	70,982	72,112

Table G-4: Forecasted Natural Gas Demand U.S. Western States (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	2,727	2,742	2,772	2,802	2,834	2,860	2,887	2,918	2,953	2,986	3,019
Commercial	1,438	1,465	1,498	1,529	1,551	1,568	1,587	1,611	1,626	1,644	1,667
Industrial	3,325	3,380	3,400	3,408	3,406	3,396	3,381	3,370	3,362	3,352	3,346
Power Generation	3,952	4,306	4,304	4,580	4,384	4,648	4,719	4,992	5,144	5,312	5,357
Total	11,442	11,892	11,973	12,319	12,175	12,472	12,574	12,890	13,085	13,294	13,390

Table G-5: Forecasted Residential Natural Gas Demand U.S. Western States (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Arizona	112	116	120	124	127	130	134	137	141	144	148
California	1,383	1,395	1,408	1,421	1,435	1,448	1,462	1,476	1,490	1,505	1,521
Colorado	349	357	362	365	368	369	368	372	377	382	386
Idaho	87	66	62	62	63	63	64	65	66	66	67
Montana	57	57	58	58	59	59	59	59	60	60	60
Nevada	108	111	115	118	121	124	127	130	134	136	140
New Mexico	95	97	98	99	100	100	101	101	102	102	102
Oregon	114	113	114	116	117	118	119	121	122	123	125
Utah	173	175	178	181	183	185	188	189	192	194	196
Washington	217	219	221	223	226	228	231	233	236	239	241
Wyoming	34	35	35	35	35	35	35	35	35	35	35
Total	2,727	2,742	2,772	2,802	2,834	2,860	2,887	2,918	2,953	2,986	3,019

Table G-6: Forecasted Commercial Natural Gas Demand U.S. Western States (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Arizona	100	102	105	108	110	112	114	117	119	121	124
California	596	601	607	616	618	620	628	638	638	642	648
Colorado	177	184	189	193	197	198	199	201	205	209	214
Idaho	4	14	25	33	37	40	42	43	44	44	45
Montana	41	42	43	44	45	45	46	46	47	47	48
Nevada	81	80	80	82	83	85	86	87	89	90	92
New Mexico	72	72	74	75	76	77	78	78	79	80	81
Oregon	83	83	84	85	86	87	88	89	91	92	93
Utah	102	102	103	104	106	107	108	109	111	112	113
Washington	154	155	157	159	161	164	166	168	171	173	176
Wyoming	30	30	31	32	32	33	33	33	33	34	34
Total	1,438	1,465	1,498	1,529	1,551	1,568	1,587	1,611	1,626	1,644	1,667

Table G-7: Forecasted Industrial Natural Gas Demand U.S. Western States (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Arizona	61	62	63	63	63	62	62	61	61	61	61
California	1,696	1,701	1,705	1,713	1,719	1,723	1,724	1,725	1,724	1,724	1,723
Colorado	507	524	531	531	529	524	517	513	512	512	512
Idaho	103	108	109	110	110	109	109	108	108	107	107
Montana	78	80	81	81	81	81	80	80	79	79	79
Nevada	31	31	31	30	30	30	29	29	29	28	29
New Mexico	94	98	100	101	100	100	99	98	98	97	97
Oregon	246	251	253	252	250	248	246	244	242	241	239
Utah	100	103	103	104	103	102	101	100	99	98	98
Washington	237	241	241	240	238	235	233	231	229	227	226
Wyoming	172	180	183	184	184	183	182	180	179	178	177
Total	3,325	3,380	3,400	3,408	3,406	3,396	3,381	3,370	3,362	3,352	3,346

Table G-8: Forecasted Power Generation Natural Gas Demand U.S. Western States (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Arizona	691	769	716	845	757	814	765	938	974	1,048	1,064
California	2,222	2,465	2,479	2,610	2,539	2,635	2,569	2,652	2,708	2,814	2,827
Colorado	271	248	238	233	228	240	253	272	286	294	292
Idaho	4	6	6	7	7	8	7	8	7	7	9
Montana	0	0	0	0	0	0	0	0	0	0	1
Nevada	303	296	298	287	301	291	394	290	427	348	340
New Mexico	32	99	175	128	118	150	169	181	183	190	200
Oregon	200	211	209	245	227	250	267	290	283	302	317
Utah	64	36	9	39	30	68	93	129	60	52	29
Washington	156	171	167	182	175	187	197	226	210	249	273
Wyoming	9	5	6	4	4	5	6	7	7	8	8
Total	3,952	4,306	4,304	4,580	4,384	4,648	4,719	4,992	5,144	5,312	5,357

Table G-9: Forecasted Canada Natural Gas Demand (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Core	5,706	5,797	5,855	5,898	5,926	5,997	6,016	6,039	6,063	6,077	6,095
Non-Core	2,497	2,704	2,938	3,176	3,499	3,653	3,884	3,973	3,944	3,956	3,928
Power Generation	777	806	874	994	1,029	1,150	1,250	1,281	1,355	1,390	1,481
Total	8,980	9,307	9,667	10,067	10,453	10,801	11,150	11,293	11,362	11,423	11,504

Table G-10: Forecasted Canada Natural Gas Demand by Canadian Provinces (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alberta	3,837	4,080	4,350	4,668	4,932	5,112	5,373	5,427	5,455	5,494	5,533
British Columbia	962	993	1,009	1,017	1,025	1,030	1,034	1,036	1,044	1,048	1,050
Canada Arctic	0	0	0	0	0	50	50	50	50	50	50
Manitoba	313	321	322	328	334	338	343	348	353	357	360
New Brunswick	59	73	111	152	221	294	335	377	377	377	377
Ontario	2,642	2,644	2,655	2,662	2,680	2,698	2,718	2,737	2,744	2,746	2,764
Quebec	571	580	592	602	612	622	633	643	654	663	675
Saskatchewan	596	616	629	639	649	658	666	675	685	688	695
Total	8,980	9,307	9,667	10,067	10,453	10,801	11,150	11,293	11,362	11,423	11,504

Table G-11: Forecasted Residential Natural Gas Demand by Canadian Western Provinces (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alberta	342	347	351	354	356	358	359	361	363	364	365
British Columbia	209	214	217	219	222	224	227	229	232	234	235
Saskatchewan	87	88	88	88	88	88	87	87	87	86	86
Total	638	649	656	661	666	670	673	677	682	684	686

Table G-12: Forecasted Commercial Natural Gas Demand by Canadian Western Provinces (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alberta	413	425	433	440	446	451	455	459	465	469	473
British Columbia	257	265	271	275	279	283	286	290	294	297	299
Saskatchewan	124	127	129	131	132	133	134	135	136	137	138
Total	794	816	833	846	857	867	875	884	894	903	910

Table G-13: Forecasted Industrial Natural Gas Demand by Canadian Western Provinces (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alberta	2,728	2,952	3,196	3,438	3,760	3,910	4,139	4,225	4,193	4,200	4,170
British Columbia	446	463	470	471	471	469	466	464	462	461	458
Saskatchewan	227	236	239	240	240	238	237	235	235	233	232
Total	3,400	3,651	3,905	4,150	4,470	4,617	4,842	4,925	4,890	4,894	4,860

Table G-14: Forecasted Power Generation Natural Gas Demand by Canadian Western Provinces (Million Cubic Feet per Day)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alberta	355	356	371	436	370	393	421	382	435	461	526
British Columbia	50	52	51	52	53	53	54	52	56	56	58
Saskatchewan	158	165	173	180	189	198	208	217	227	232	238
Total	563	573	594	667	613	645	683	652	718	749	821

Source: Tables G-1 through G-14 California Energy Commission staff

APPENDIX H: FORECASTED NATURAL GAS WELLHEAD PRODUCTION

Table H-1: Forecasted Natural Gas Wellhead Production MMcfd

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
United States											
South and Central Alaska	741	746	782	770	818	795	879	798	724	658	598
North Alaska	0	0	0	0	0	0	0	0	112	291	318
Alaska Subtotal	741	746	782	770	818	795	879	798	836	949	916
California	883	879	856	831	809	864	861	842	823	806	790
Eastern States	1,603	1,558	1,516	1,479	1,446	1,415	1,361	1,302	1,234	1,173	1,118
Midcontinent States	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563
Midwest States	1,008	1,441	1,441	1,585	1,873	2,110	1,996	1,835	1,683	1,547	1,579
Northern Great Plains	276	250	228	213	253	271	262	254	246	239	300
Permian	4,422	4,045	3,816	3,867	4,063	4,123	3,945	3,668	3,614	4,092	4,595
Rocky Mountains	9,354	9,297	9,200	9,252	9,253	9,804	9,654	9,413	9,377	9,446	9,391
San Juan	4,264	4,264	4,223	4,221	4,264	4,198	3,903	3,597	3,335	3,110	2,906
Southeastern Gulf of Mexico Offshore	2,752	2,712	2,802	2,875	2,884	2,828	2,780	2,727	2,624	2,544	2,468
Southeastern Gulf of Mexico Onshore	8,150	8,813	9,193	8,922	9,104	9,792	10,111	10,656	10,640	10,439	10,642
Southeastern Gulf of Mexico Subtotal	10,902	11,525	11,995	11,797	11,988	12,619	12,891	13,383	13,264	12,982	13,110
Texas Offshore	1,089	987	903	819	752	686	630	612	1,083	1,775	2,234
Texas Onshore	12,737	12,584	12,336	12,643	13,130	13,339	13,222	13,095	12,927	12,790	12,675
Texas Subtotal	13,826	13,571	13,239	13,462	13,883	14,025	13,852	13,707	14,010	14,565	14,909
Total US Natural Gas Production	53,843	54,137	53,859	54,040	55,213	56,787	56,166	55,361	54,985	55,474	56,176
Canada											
Western Sedimatary Basis	18,082	17,213	16,925	17,417	18,040	18,737	19,016	18,930	18,707	18,170	17,698
Eastern Canada	506	541	541	541	541	765	803	836	877	893	893
Northern Canada	0	0	0	0	0	54	54	54	54	54	54
Total Canada Natural Gas Production	18,588	17,754	17,466	17,958	18,581	19,556	19,873	19,820	19,638	19,116	18,645
Mexico											
Burgos Field	1,268	1,151	1,099	1,248	1,474	1,961	2,453	2,937	3,524	4,158	4,792
Vera Cruz Field	40	40	40	40	40	40	40	40	40	40	40
Yucatan Field	1,726	1,783	2,059	2,572	2,869	3,093	3,279	3,424	3,576	3,757	3,952
Tampico-Misantla Field	39	40	40	40	40	40	40	40	40	40	40
Total Mexico Natural Gas Production	3,072	3,014	3,238	3,900	4,423	5,134	5,812	6,441	7,181	7,996	8,824

Source: California Energy Commission Staff

APPENDIX I: FORECASTED LIQUEFIED NATURAL GAS MARKETED IN NORTH AMERICA

Table I-1: Forecasted Liquefied Natural Gas Marketed in North America MMcfd

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada											
Nova Scotia	-	-	-	-	-	714	714	714	714	714	714
United States											
Cameron Louisiana	-	612	856	856	856	856	856	856	856	856	856
Corpus Christi Texas	-	-	-	-	357	571	571	571	571	571	571
Cove Point Maryland	714	714	1,121	1,284	1,284	1,284	1,284	1,284	1,284	1,284	1,284
Elba Island Georgia	856	856	856	856	856	856	856	856	856	856	856
Everett Mass	765	765	765	765	765	765	765	765	765	765	765
Freeport Texas	-	-	765	1,070	1,070	1,070	1,962	2,319	2,319	2,319	2,319
Golden Pass/East of River	-	-	-	816	1,142	1,142	1,142	1,142	1,142	1,142	1,142
Lake Charles Louisiana	571	1,060	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256
Sabine Pass Louisiana	530	848	954	1,060	1,166	1,272	1,378	1,770	2,283	2,283	2,283
United States Subtotal	3,435	4,854	6,573	7,963	8,752	9,073	10,071	10,819	11,333	11,333	11,333
Mexico											
Altamira Mexico	510	510	510	510	510	510	510	510	510	510	510
Baja Mexico	-	255	816	816	816	816	816	816	1,580	1,886	1,886
Mexico Subtotal	510	765	1,325	1,325	1,325	1,325	1,325	1,325	2,090	2,396	2,396
Total LNG	3,945	5,619	7,898	9,289	10,078	11,111	12,109	12,858	14,136	14,442	14,442

Source: California Energy Commission Staff

APPENDIX J: CALIFORNIA NATURAL GAS SUPPLY AND DEMAND FORECAST

Table J-1: PG&E Forecasted Natural Gas Supply and Demand

MMcfd

Supply	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
California Production	143	150	150	150	150	150	150	150	150	135
Malin - GTN	1,268	1,148	1,043	1,282	1,236	1,360	1,354	1,364	1,338	937
Topock - El Paso	267	515	612	187	198	141	126	161	152	532
Dagget - Kern River/Mojave	410	410	410	828	817	873	888	854	863	977
Supply Sum	2,087	2,223	2,214	2,447	2,401	2,524	2,518	2,529	2,502	2,582

Demand	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Residential	558	563	570	576	583	590	597	604	612	619
Commercial	239	239	240	242	242	242	244	247	246	247
Industrial	440	445	448	451	453	455	456	457	458	459
PG&E EG Backbone	336	401	416	624	587	609	604	635	627	664
PG&E EG Local Trans.	341	369	334	350	336	346	336	338	333	344
SMUD EG	102	119	121	121	121	122	124	124	125	127
Demand Sum	2,016	2,137	2,128	2,364	2,322	2,364	2,361	2,406	2,401	2,460
Losses	71	86	86	82	79	160	157	123	102	122
Percent of Supply	3%	4%	4%	3%	3%	6%	6%	5%	4%	5%

Source: California Energy Commission Staff
2007 is forecasted

Table J-2: SoCal Gas Forecasted Natural Gas Supply and Demand

MMcfd

Supply	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Topock	1,299	1,299	1,299	1,617	1,617	1,617	1,617	1,617	1,488	1,330	1,298
Blythe	753	837	776	443	457	507	496	529	706	878	934
Kern-Adelanto	199	152	77	-	-	-	-	-	-	-	-
Calif. Offshore	68	68	68	68	68	68	68	68	68	68	68
Calif. Los Angeles Basin	189	189	178	165	154	144	133	122	113	105	99
Supply Sum	2,507	2,546	2,398	2,293	2,296	2,336	2,314	2,336	2,375	2,381	2,399

Demand	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	733	739	744	750	755	760	766	772	778	784	791
Commercial	314	318	322	327	329	331	336	342	342	345	349
Industrial	460	464	465	468	469	470	470	470	470	470	470
Electric Generation	688	769	819	703	697	728	696	706	737	734	741
SDG&E Off system	265	206	-	-	-	-	-	-	-	-	-
Demand Sum	2,460	2,497	2,350	2,247	2,250	2,290	2,268	2,290	2,327	2,334	2,351
Losses	47	49	48	46	46	47	46	47	47	48	48
Percent of Supply	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%

Source: California Energy Commission Staff
2007 is forecasted

Table J-3: SDG&E Forecasted Natural Gas Supply and Demand MMcfd

Supply	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
TGN	-	62	269	248	254	259	270	277	307	339	339
SoCal Gas	265	206	-	-	-	-	-	-	-	-	-
Supply Sum	265	268	269	248	254	259	270	277	307	339	339

Demand	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	92	93	95	96	97	98	99	100	101	102	104
Commercial	43	44	45	46	47	47	48	49	49	50	51
Industrial	11	11	11	11	11	11	12	12	12	12	12
Electric Generation	116	117	115	92	96	100	108	113	141	172	170
Demand Sum	262	265	266	245	251	256	266	274	304	336	336
Losses	3	3	3	3	3	3	3	3	3	3	3
Percent of Supply	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

Source: California Energy Commission Staff
2007 is forecasted

Table J-4: California Nonutility Forecasted Natural Gas Supply and Demand MMcfd

Supply	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
California Production	483	472	459	448	436	426	416	405	397	405	384
El Paso	1	62	82	81	71	82	77	81	95	179	181
Kern/Mojave	1,047	1,043	1,010	1,009	1,013	1,040	1,024	1,061	1,057	992	994
TGN	-	-	6	65	66	68	70	71	76	76	76
Supply Sum	1,531	1,576	1,558	1,602	1,586	1,615	1,587	1,619	1,625	1,652	1,636

Demand	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
EG Calif Prod	70	73	73	68	67	71	73	74	75	76	75
EG Kern/Mojave	334	364	346	341	334	346	319	347	352	373	361
EG Coolwater	18	23	20	18	15	16	11	15	12	16	13
EOR Steaming	785	781	781	784	786	787	786	786	785	783	781
EOR Cogen	156	164	164	164	164	164	163	164	163	164	163
EG Blythe	61	66	66	63	56	65	66	66	66	69	69
EG Otay Mesa	-	-	6	65	66	68	70	71	76	76	76
Demand Sum	1,424	1,471	1,456	1,503	1,488	1,517	1,488	1,522	1,529	1,555	1,540
Losses	108	106	102	99	98	99	98	97	96	97	96
Percent	7%	7%	7%	6%	6%	6%	6%	6%	6%	6%	6%

Note: El Paso supply includes Line 1903 flows
EOR Cogen is for natural gas used for electric generation
EOR Steaming includes process heat from cogeneration

Source: California Energy Commission Staff
2007 is forecasted

Table J-5: California Statewide Forecasted Natural Gas Supply and Demand MMcfd

Supply	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Calif Production	883	879	856	831	809	788	767	746	728	714	701
Malin	1,312	1,189	1,079	1,326	1,279	1,407	1,401	1,412	1,384	970	957
Kern River	1,545	1,504	1,426	1,635	1,627	1,716	1,716	1,713	1,716	1,716	1,716
Topock	1,677	1,915	1,982	2,005	2,019	1,955	1,939	1,980	1,844	2,115	2,085
Blythe - SW	937	894	638	224	306	398	419	471	-	-	75
Blythe - No. Baja	-	-	216	291	216	185	152	135	804	1,061	1,049
Otay Mesa	-	62	274	313	319	327	340	348	382	415	416
Supply Sum	6,353	6,441	6,471	6,626	6,575	6,776	6,735	6,804	6,858	6,991	6,998

Demand	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	1,382	1,395	1,408	1,421	1,435	1,448	1,462	1,476	1,490	1,505	1,521
Commercial	596	601	607	616	618	620	628	638	638	642	648
Industrial	1,696	1,701	1,705	1,713	1,719	1,723	1,724	1,725	1,724	1,724	1,723
Electric Generation	2,222	2,465	2,479	2,610	2,539	2,635	2,569	2,652	2,708	2,814	2,827
Demand Sum	5,897	6,163	6,199	6,360	6,311	6,426	6,384	6,492	6,560	6,684	6,718
Losses	456	278	272	266	264	350	351	312	298	307	280
Percent of Supply	0.07	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.04	0.04	0.04

Note: Industrial includes natural gas used for process heat in EOR cogeneration
Electric Generation includes natural gas used for electric generation in EOR cogeneration

Source: California Energy Commission Staff
2007 is forecasted

APPENDIX K, TABLE K-1: CALIFORNIA NATURAL GAS PIPELINE CAPACITIES

MMcfd

PG&E		Capacity
Redwood Path		1,850
Baja Path		1,140
SoCal Gas		
North System		
	El Paso	594
	Transwestern	750
	Sum	1,344
South System		1,240
SDG&E		
Rainbow		500
TGN		400
Calif. Receiving Capacity		
Malin		2,100
Topock		
	PG&E	1,140
	SoCal from Transwestern	790
	SoCal from El Paso	540
	Mojave	400
	Sum	2,870
Blythe		
SoCal Gas		1,240
El Paso Line 1903		500
	Sum	1,740
Kern River		1,760
Line 1903		500
Pipeline Delivery Capacity		
GTN at Malin		2,100
El Paso No./Transwestern/So. Trails at Topock		
	El Paso	1,680
	Transwestern	550
	So. Trails	100
	Sum	2,330
El Paso So/ No.Baja at Blythe		
	El Paso So	1,240
	El Paso All American	500
	North Baja flowing North	1,500
	Sum	3,240

Source: California Energy Commission Staff

Note: Transwestern has 500 MMcfd stranded capacity at the California Border due to the new Phoenix lateral.

APPENDIX L: CALIFORNIA NATURAL GAS PIPELINE CAPACITIES

Table L-1: California Forecasted Natural Gas Pipeline Capacity Factors

PG&E Capacity Factors	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Redwood	69%	62%	56%	69%	67%	73%	73%	74%	72%	51%	50%
Baja Path											
Topock to Daggett	23%	45%	54%	16%	17%	12%	11%	14%	13%	47%	43%
Daggett to Kern Station	59%	81%	90%	89%	89%	89%	89%	89%	89%	132%	132%
Kern Station to San Fran	59%	81%	90%	89%	89%	89%	89%	89%	89%	132%	132%
SoCal Gas Capacity Factors											
Northern System	97%	97%	97%	120%	120%	120%	120%	120%	111%	99%	97%
Southern System	61%	68%	63%	36%	37%	41%	40%	43%	57%	71%	75%
SDG&E Capacity Factors											
Rainbow	53%	41%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Otay Mesa	0%	15%	67%	62%	63%	65%	67%	69%	77%	85%	85%
Utility Receiving Capacity Factors											
Malin	62%	57%	51%	63%	61%	67%	67%	67%	66%	46%	46%
Topock	56%	64%	67%	68%	68%	66%	65%	67%	62%	71%	70%
Blythe	54%	51%	49%	30%	30%	33%	33%	35%	46%	61%	65%
Kern River	88%	85%	81%	93%	92%	97%	97%	97%	97%	97%	97%
Pipeline Delivery Capacity Factors											
GTN at Malin	62%	57%	51%	63%	61%	67%	67%	67%	66%	46%	46%
El Paso No./Trans/So. Trails at Topock	72%	82%	85%	86%	87%	84%	83%	85%	79%	91%	89%
El Paso So/ No.Baja at Blythe	29%	28%	26%	16%	16%	18%	18%	19%	25%	33%	35%

Source: California Energy Commission Staff
2007 is forecasted

APPENDIX M: FORECASTED ANNUAL AVERAGE NATURAL GAS HUB PRICES

Table M-1: Forecasted Annual Average Natural Gas Hub Prices 2006 Dollars per Mcf

	Chicago	New York	Opal	AECO	Malin	So Calif	El Paso San Juan	Cheyenne	Henry Hub
Historical									
2003	5.59	6.05	4.48	4.60	4.89	4.93	4.60	4.67	5.50
2004	5.86	6.64	5.21	5.13	5.45	5.57	5.13	5.19	5.97
2005	8.22	9.46	6.88	6.92	7.33	7.82	6.92	7.13	8.11
2006	6.72	7.23	4.97	5.66	6.04	6.07	5.66	5.72	6.41
Forecasted									
2007	5.43	6.13	4.50	4.51	5.15	5.12	4.84	4.65	5.50
2008	5.64	6.25	4.74	4.79	5.45	5.37	5.08	4.91	5.58
2009	5.62	6.18	4.72	4.83	5.46	5.34	5.05	5.12	5.51
2010	5.82	6.24	4.98	5.09	5.87	5.57	5.26	5.34	5.65
2011	6.06	6.45	5.19	5.21	5.97	5.79	5.48	5.56	5.89
2012	6.39	6.87	5.38	5.64	6.46	6.09	5.76	5.88	6.21
2013	6.59	7.05	5.64	5.82	6.67	6.34	6.00	6.07	6.36
2014	6.80	7.24	5.92	6.03	6.93	6.61	6.26	6.28	6.54
2015	6.97	7.40	6.03	6.20	7.12	6.76	6.41	6.43	6.66
2016	7.38	7.84	6.47	6.59	7.41	7.24	6.86	6.78	7.06
2017	7.69	8.17	6.76	6.89	7.77	7.53	7.15	7.07	7.35

Source: California Energy Commission Staff and Natural Gas Week

APPENDIX N: FORECASTED ANNUAL AVERAGE NATURAL GAS WELLHEAD PRICES

Table N-1: Forecasted Annual Average Natural Gas Wellhead Prices 2006 Dollars per Mcf

Production Region	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
United States											
Alaska	2.15	3.96	1.84	4.31	1.43	4.82	0.84	9.02	1.10	1.39	2.53
California	5.36	5.62	5.56	5.81	6.04	6.36	6.62	6.90	7.02	7.54	7.84
Eastern States	5.75	5.91	5.85	6.00	6.25	6.65	6.83	7.03	7.18	7.61	7.92
Midcontinent States	5.09	5.30	5.27	5.51	5.74	6.07	6.26	6.47	6.62	7.01	7.29
Midwestern States	5.59	5.76	5.73	5.91	6.15	6.48	6.69	6.90	7.07	7.50	7.80
North Great Plains	4.72	5.00	5.03	5.30	5.47	5.83	6.05	6.30	6.47	6.90	7.16
Permian Basin	4.97	5.18	5.14	5.33	5.54	5.85	6.05	6.28	6.42	6.79	7.05
Rocky Mountains	4.51	4.76	4.78	5.03	5.23	5.45	5.69	5.96	6.08	6.48	6.78
San Juan Basin	4.69	4.92	4.89	5.10	5.31	5.59	5.82	6.07	6.23	6.67	6.95
Southeastern Gulf of Mexico Offshore	4.47	4.79	4.73	4.52	4.64	5.00	5.26	5.60	5.86	6.10	6.50
Southeastern Gulf of Mexico Onshore	2.51	2.31	2.22	2.37	2.41	2.46	2.40	2.30	2.29	2.42	2.42
Southeastern Gulf of Mexico Average	3.00	2.90	2.81	2.89	2.94	3.03	3.02	2.97	3.00	3.14	3.19
Texas Offshore	5.21	5.34	5.27	5.40	5.58	5.90	6.04	6.21	6.34	6.67	6.91
Texas Onshore	4.21	4.34	4.28	4.44	4.62	4.88	5.01	5.15	5.25	5.51	5.69
Texas Average	4.29	4.41	4.35	4.50	4.67	4.93	5.06	5.20	5.33	5.65	5.88
United States Average	4.31	4.45	4.36	4.57	4.70	4.97	5.03	5.25	5.24	5.56	5.79
Canada											
Western Sedimatary Basis	4.32	4.61	4.64	4.91	5.01	5.41	5.58	5.79	5.96	6.35	6.67
Eastern Canada	5.52	0.77	0.77	0.77	0.74	5.84	6.07	6.28	6.45	6.85	7.17
Northern Canada	1.21	1.19	1.28	1.31	0.95	1.58	0.97	1.66	0.92	1.80	0.86
Canadian Average	4.35	4.49	4.52	4.78	4.88	5.41	5.59	5.80	5.97	6.36	6.67
Mexico											
Burgos Field	3.97	5.06	4.93	5.23	5.21	5.40	5.64	5.69	5.93	6.14	6.48
Tampico-Misantla Field	4.11	5.23	4.94	5.42	5.38	5.56	5.71	5.76	6.10	6.32	6.45
Vera Cruz Field	4.40	5.44	5.11	5.64	5.57	5.74	5.89	5.93	6.00	6.13	6.25
Yucatan Field	4.11	5.10	4.78	5.26	5.19	5.34	5.24	5.50	5.35	5.70	5.58
Mexico Average	4.05	5.09	4.83	5.26	5.20	5.37	5.42	5.59	5.64	5.93	6.07

Source: California Energy Commission Staff

APPENDIX O: CALIFORNIA FORECASTED NATURAL GAS BORDER PRICES

Table O-1: Forecasted Natural Gas Prices at the California Border 2006 Dollars per Mcf

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Calif Production	5.36	5.62	5.56	5.81	6.04	6.36	6.62	6.90	7.02	7.54	7.84
Malin	5.15	5.45	5.46	5.87	5.97	6.46	6.67	6.93	7.12	7.41	7.77
Kern River	5.06	5.33	5.28	5.62	5.85	6.14	6.39	6.67	6.82	7.35	7.64
Topock	5.20	5.47	5.44	5.65	5.88	6.18	6.43	6.71	6.86	7.36	7.65
Blythe	5.24	5.47	5.41	5.57	5.80	6.14	6.37	6.65	6.65	7.10	7.37
Otay Mesa	-	5.62	5.23	5.38	5.61	5.95	6.18	6.45	6.42	6.76	7.11
Costa Azul	-	5.62	5.23	5.38	5.61	5.95	6.18	6.45	6.42	6.76	7.11

Note: Otay Mesa is Baja California Wholesale Gas
Costa Azul is Baja Regas Existing

Source: California Energy Commission staff

APPENDIX P: NATURAL GAS END-USE PRICE FORECASTING METHODOLOGY - JANUARY 30, 2007

1. **General Assumptions**
   All natural gas prices used in this analysis are expressed in real or constant 2006 dollars per Mcf (thousand cubic feet). Implicit price deflators were used to convert any changes in price bases. The deflators used are in **Table P-5**.

   The price a customer pays for natural gas has several components. These include the costs associated to find, produce and condition the natural gas into a marketable product, pipeline transport costs and utility distribution costs. The assumptions regarding the utility distribution costs follow.

   There are several demand centers in California that are considered in the Energy Commission's staff analysis. Each has one or more sources of supply that meet its needs. **Table P-1** denotes these demand centers and supply sources. Some may receive supply indirectly as SoCal Gas' receipts of LNG from Costa Azul via the Baja North pipeline at Blythe. In this instance, it would be treated as a supply mixed with southwest production.

Table P-1: Direct Natural Gas Supply Sources for California Service Areas

Service Area	Calif. Production	Canada	Rocky Mountains	Southwest	LNG
PG&E	x	x	x	x	
SoCal Gas	x		x	x	
SDG&E			x	x	x
EOR	x		x	x	
Non Utility Electric Gen	x		x	x	

Source: California Energy Commission staff

Each supply is received at the border with a price equal to the commodity price, transportation, and regional pricing transactions. Regional pricing differentials occur when the model reaches pricing equilibrium. At this point, these transactions would be added to or subtracted, depending on the competition between the supply areas and demand centers. For instance, regasified LNG could have a cost of $5.00 but a market clearing price of $7.00. This extra $2.00 would be included in the border price. At the same time, a competing supply might drop from $7.50 to $7.00. A $0.50 loss would occur to this supply.

For each demand center, the supply is mixed and a weighted average price is determined by staff, as shown in **Tables P-2** and **P-3.** The weighted average cost of gas (WACOG) is applied to all demand being serviced in the same area. Staff has not determined long term versus spot prices or fixed and discounted transport costs. Staff assumed that the model's border prices include the results of these business deals.

Staff did not forecast the margin or allocation of these costs. Instead, the rates effective in January 2007 were held constant over the period in real 2006 dollars. Staff's past analysis found little variation in these costs for the forecasted period. Additionally, recent CPUC Biennial Cost Allocation Proceeding decisions have held constant utility revenue requirements in real terms.

Assumptions for each utility were slightly different in terms of how staff applied the current rate structures. These are discussed below.

2. PG&E

For PG&E, staff used the recently adopted "Gas Accord III Settlement Agreement," CPUC D0412050 Opinion Adopting Gas Accord Settlement III. Backbone and transport costs for the Redwood and Baja systems were applied to natural gas delivered to the PG&E city gate. Staff also used local distribution rates from that point. Staff also separated power plants into those receiving local distribution and backbone service. SMUD's separate transportation agreements were also accounted for in the forecasting analysis. All pipeline transport costs, including off-system delivery rates to SoCal Gas, were based on the annual firm transportation rates.

3. SoCal Gas

Recent SoCal Gas tariff sheets were used by staff with some modification. For those schedules with a declining block, a share of demand was assumed for each block to obtain a weighted average rate for that schedule. The recent decision regarding implementation of firm access rights was not included in the forecasting analysis.

4. SDG&E

For SDG&E, rate treatment was similar to SoCal Gas. Recent tariff sheets were used with some modification. For those schedules with a declining block, a share of demand was assumed for each block to obtain a weighted average rate for that schedule. The recent decision regarding implementation of firm access rights was not included in the forecasting analysis

One difference was the treatment of SoCal Gas's delivery cost to SDG&E. It was treated as a backbone rate and not a commodity rate. Since the SoCal Gas delivery charge is written into each distribution rate, these rates were adjusted downward to accommodate the backbone treatment that was being used. Additionally, LNG was available at a price received at the San Diego County – Mexican border.

5. Nonutility Service

For those receiving nonutility service, no additional distribution costs were added. The total price was the interstate delivery price to California, or for California production, its wellhead price.

Table P-2: Forecasted Utility Retail Natural Gas Prices

2006 Dollars per Mcf

PG&E	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	9.92	10.24	10.24	10.70	10.79	11.34	11.56	11.84	12.04	12.33	12.70
Commercial	8.88	9.20	9.19	9.66	9.75	10.30	10.52	10.79	11.00	11.28	11.66
Industrial (Chem)	7.05	7.36	7.36	7.82	7.92	8.46	8.69	8.96	9.17	9.45	9.82
Industrial (Non-Chem)	7.04	7.36	7.36	7.82	7.91	8.46	8.68	8.95	9.16	9.44	9.82

SoCal Gas	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	9.93	10.19	10.12	10.26	10.50	10.86	11.11	11.40	11.42	11.91	12.21
Commercial	8.89	9.15	9.07	9.22	9.45	9.82	10.06	10.36	10.38	10.87	11.17
Industrial (Chem)	7.05	7.31	7.24	7.38	7.62	7.99	8.23	8.52	8.55	9.04	9.34
Industrial (Non-Chem)	7.06	7.32	7.25	7.39	7.63	8.00	8.24	8.53	8.55	9.05	9.35

SDG&E	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Residential	10.00	10.26	9.87	10.04	10.28	10.63	10.88	11.16	11.14	11.50	11.86
Commercial	8.96	9.22	8.84	9.00	9.24	9.60	9.84	10.12	10.10	10.46	10.83
Industrial (Chem)	7.13	7.39	7.01	7.17	7.41	7.77	8.01	8.30	8.27	8.63	9.00
Industrial (Non-Chem)	7.13	7.39	7.01	7.17	7.41	7.77	8.01	8.30	8.27	8.63	9.00

Source: California Energy Commission Staff

Table P-3: Forecasted Annual Average Natural Gas Prices for Electricity Generation 2006 Dollars per Mcf

Electric Generation Areas	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Northern California											
PG&E Backbone	5.67	5.98	5.98	6.45	6.54	7.08	7.31	7.58	7.79	8.07	8.45
PG&E Local Transmission	5.82	6.14	6.14	6.60	6.69	7.24	7.46	7.73	7.94	8.22	8.60
SMUD	5.62	5.94	5.93	6.39	6.49	7.03	7.26	7.53	7.74	8.02	8.39
Southern California											
SoCal Gas	5.63	5.86	5.80	5.96	6.19	6.53	6.76	7.04	7.04	7.49	7.76
SDG&E	5.93	6.18	5.80	5.96	6.20	6.55	6.79	7.07	7.04	5.84	7.75
California Nonutility											
EOR Steaming	5.61	5.88	5.83	6.15	6.39	6.71	6.99	7.28	7.45	8.01	8.32
Kern-Mojave	5.06	5.33	5.28	5.62	5.85	6.14	6.39	6.67	6.82	7.35	7.64
California Source Gas	5.61	5.88	5.83	6.15	6.39	6.71	6.99	7.28	7.45	8.01	8.32
Cool Water	5.82	6.14	6.13	6.59	6.69	7.23	7.46	7.73	7.94	8.22	8.59
Otay Mesa	5.92	6.18	5.80	5.96	6.20	6.55	6.79	7.06	7.04	5.84	7.75
Southwest States											
Arizona North	5.15	5.41	5.38	5.60	5.83	6.13	6.38	6.64	6.80	7.28	7.57
Arizona South	5.30	5.55	5.49	5.68	5.90	6.24	6.48	6.75	6.84	7.24	7.51
Las Vegas	5.35	5.60	5.57	5.79	6.02	6.32	6.58	6.84	7.01	7.47	7.77
Reno	5.41	5.75	5.77	6.21	6.24	6.69	6.88	7.15	7.36	7.78	8.22
New Mexico	4.96	5.20	5.17	5.39	5.61	5.90	6.14	6.41	6.57	7.03	7.32
Pacific Northwest											
Kingsgate	4.81	5.12	5.15	5.48	5.59	6.03	6.23	6.47	6.65	7.02	7.36
Stanfield	4.94	5.25	5.26	5.63	5.73	6.19	6.39	6.63	6.82	7.17	7.51
Malin	5.16	5.46	5.46	5.88	5.97	6.47	6.68	6.93	7.12	7.42	7.77
Oregon/Coastal	5.18	5.50	5.52	5.96	5.98	6.42	6.62	6.88	7.09	7.49	7.90
Wash/Coastal	5.18	5.51	5.52	5.96	5.99	6.42	6.63	6.88	7.09	7.49	7.90
Rocky Mountains											
Idaho	5.60	5.92	5.94	6.38	6.41	6.84	7.04	7.30	7.51	7.90	8.30
Colorado	5.55	6.07	6.04	6.53	6.49	7.42	7.75	7.69	7.73	7.75	8.06
Montana	5.35	5.64	5.68	5.96	6.15	6.54	6.76	7.02	7.21	7.65	7.94
Utah	5.14	5.40	5.37	5.66	5.87	6.08	6.37	6.67	6.77	7.24	7.55
Wyoming	5.35	5.61	5.59	5.87	6.08	6.28	6.56	6.85	6.97	7.43	7.75
Kern	4.96	5.22	5.18	5.51	5.73	6.02	6.26	6.53	6.68	7.20	7.48
Canada											
Alberta	5.14	5.45	5.50	5.78	5.93	6.39	6.59	6.81	7.00	7.42	7.75
British Columbia	5.28	5.61	5.63	6.05	6.05	6.41	6.59	6.83	7.04	7.43	7.85
Saskatchewan	5.14	5.43	5.46	5.74	5.88	6.32	6.52	6.73	6.91	7.33	7.65

Note: Prices for EOR steaming are based on a weighted average for supply from SoCal Gas, Kern-Mojave, and California Production

Source: California Energy Commission Staff

Table P-4: Electricity Generation Fuel Group Definitions

California	
Coolwater	Topock WACOG plus Mojave transport
Mojave	Topock WACOG plus Mojave transport
Otay Mesa	North Baja Pipeline WACOG at Otay Mesa plus across border transport
PG&E Back Bone PP	PG&E WACOG plus backbone
PG&E Old PP	PG&E WACOG plus backbone and local distribution
SDG&E	Southern Calif Utility WACOG plus SCG transport and SDG&E EG distribution
SMUD < 85 MMcfd	PG&E WAGOG plus reduce back bone
SMUD > 85 MMcfd	PG&E WAGOG plus reduce back bone
So. Calif Prod.	So. Calif production
SoCal Gas	Southern Calif Utility WACOG plus EG Distribution
TEOR	WACOG of supply from SoCal Gas, Kern/Mojave pipelines and California production.

Canada	
Alberta	Alberta wellhead plus transport
British Columbia	British Columbia wellhead plus transport

Rocky Mtns	
Colorado	Rocky Mountain Wellhead Price plus transport
Montana	Rocky Mountain Wellhead Price plus transport
Rockies Idaho	Rocky Mountain Wellhead Price plus transport
Rockies Utah	Rocky Mountain Wellhead Price plus transport
Rockies WY/CO	Rocky Mountain Wellhead Price plus transport

SW Desert	
EPN-Az	El Paso North/Transwestern WACOG
EPN-NM	El Paso North/Transwestern WACOG
EPS-Az	El Paso South WACOG
EPS-NM	El Paso South WACOG
SW Desert Utility	SW Desert WACOG plus utility transport

Nevada	
Nev-No	Tuscarora and Paiute WACOG
Nev-So	Kern River and SW Gas WACOG
Kern River	Kern River WACOG

Pacific Northwest	
GTN -Kingsgate	GTN WACOG at Kingsgate
GTN -Stansfield	GTN WACOG at Stansfield
GTN -Malin	GTN WACOG at Malin
Oregon/Coastal	PNW WACOG plus utility transport
Washington/Coastal	Northwest Pipeline WACOG from Sumas

North Baja Pipeline	
PP in Mexico	North Baja WACOG in Mexico
El Centro	North Baja WACOG in California

Table P-5: GDP Price Deflator

2006 Demand Analysis Office
GDP Implicit Price Deflator (2006 = 100)
5/30/2006

YEAR	INDEX	ANNUAL GROWTH RATE
1970	23.78	
1971	24.96	5.0%
1972	26.05	4.3%
1973	27.50	5.6%
1974	29.99	9.1%
1975	32.81	9.4%
1976	34.71	5.8%
1977	36.91	6.3%
1978	39.50	7.0%
1979	42.78	8.3%
1980	46.67	9.1%
1981	51.05	9.4%
1982	54.17	6.1%
1983	56.30	3.9%
1984	58.42	3.8%
1985	60.20	3.0%
1986	61.53	2.2%
1987	63.20	2.7%
1988	65.36	3.4%
1989	67.83	3.8%
1990	70.46	3.9%
1991	72.92	3.5%
1992	74.59	2.3%
1993	76.32	2.3%
1994	77.94	2.1%
1995	79.54	2.0%
1996	81.04	1.9%
1997	82.39	1.7%
1998	83.31	1.1%
1999	84.51	1.4%
2000	86.35	2.2%
2001	88.43	2.4%
2002	89.97	1.7%
2003	91.79	2.0%
2004	94.21	2.6%
2005	96.84	2.8%
2006	100.00	3.3%
2007	102.96	3.0%
2008	105.35	2.3%
2009	107.53	2.1%
2010	109.71	2.0%
2011	111.96	2.0%
2012	114.16	2.0%
2013	116.39	1.9%
2014	118.61	1.9%
2015	120.88	1.9%
2016	123.17	1.9%
2017	125.48	1.9%
2018	127.82	1.9%
2019	130.19	1.9%
2020	132.63	1.9%

Source: California Energy Commission Staff
Demand Assessments Office, May 30, 2006

APPENDIX Q: FORECASTED NATURAL GAS WELLHEAD PRODUCTION

Table Q-1: Forecasted Prices for Liquefied Natural Gas Sold in North America
2006 Dollars per Mcf

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada											
Nova Scotia	-	-	-	-	-	5.84	6.07	6.28	6.45	6.85	7.17
United States											
Cameron Louisiana	-	5.54	5.46	5.59	5.81	6.13	6.29	6.46	6.58	6.98	7.26
Corpus Christi Texas	-	-	-	-	5.58	5.90	6.04	6.21	6.34	6.68	6.91
Cove Point Maryland	6.01	6.14	6.04	6.13	6.37	6.81	6.99	7.20	7.34	7.79	8.12
Elba Island Georgia	5.62	5.71	5.65	5.75	6.02	6.41	6.59	6.79	7.03	7.35	7.69
Everett Mass	6.39	6.54	6.48	6.63	6.91	7.29	7.51	7.73	7.91	8.39	8.73
Freeport Texas	-	-	5.30	5.43	5.62	5.94	6.04	6.17	6.30	6.49	6.84
Golden Pass/East of River	-	-	-	5.38	5.56	5.87	6.02	6.20	6.32	6.66	6.90
Lake Charles Louisiana	5.48	5.54	5.46	5.59	5.81	6.13	6.29	6.46	6.58	6.98	7.26
Sabine Pass Louisiana	5.38	5.45	5.37	5.49	5.70	6.03	6.18	6.34	6.46	6.84	7.12
United States Average	5.81	5.80	5.67	5.74	5.93	6.27	6.39	6.54	6.67	7.02	7.32
Mexico											
Altamira Mexico	4.11	5.23	4.94	5.42	5.38	5.56	5.71	5.76	6.10	6.32	6.45
Baja Mexico	-	5.62	5.23	5.38	5.61	5.95	6.18	6.45	6.42	6.76	7.11
Mexico Average	4.11	5.36	5.12	5.40	5.52	5.80	6.00	6.18	6.34	6.67	6.97

Source: California Energy Commission Staff