CALIFORNIA
ENERGY
COMMISSION

Natural Gas Market Assessment

STAFF REPORT

Prepared in Support of the *Electricity and Natural Gas Report* under the Integrated Energy Policy Report Proceeding (02-IEP-01)

AUGUST 2003
100-03-006

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

Leon Brathwaite
Mark DiGiovanna
Jim Fore
Jairam Gopal
Mignon Marks
Lynn Marshall
Dave Maul
Todd Peterson
Angela Tanghetti
David Vidaver
Bill Wood
Principal Authors

Jairam Gopal
Project Manager
NATURAL GAS MARKET ASSESSMENT

Al Alvarado
Project Manager
ELECTRICITY AND NATURAL GAS REPORT

Karen Griffin
Program Manager
INTEGRATED ENERGY POLICY REPORT

Dave Maul
Manager
NATURAL GAS AND SPECIAL PROJECTS OFFICE

Terrence O'Brien
Deputy Director
SYSTEMS ASSESSMENT AND FACILITIES SITING DIVISION

Robert L. Therkelsen
Executive Director

Acknowledgements

Tajinder Grewal
Lorne Prescott
Jake Taylor
Pam Yoo
Students

Aspen Environmental Group
Mary Dyas
Editing & Production

Table of Contents

Table of Contents 4

List of Figures 6

List of Tables 7

Executive Summary i
- Introduction i
- Assessment Methodology i
- Key Findings and Conclusions ii
  - Demand Trends ii
  - Supply Trends ii
  - Price Projections iii
  - Infrastructure Trends iii
  - Natural Gas Storage iv
  - Scenarios iv
  - Policy Implications v

Chapter 1: Introduction 1
- The Future of the Natural Gas Market 1
- Past and Current Trends in the Natural Gas Market 1
- The Energy Crisis 2

Chapter 2: Basecase 5
- Introduction 5
  - NARG Model Assessment Methodology 5
- Natural Gas Demand 11
  - Modeling Assumptions and Data Sources 11
  - Natural Gas Demand Assumptions 11
  - Natural Gas Consumption in the Basecase 15
- Natural Gas Supply 18
  - Supply Assessment Methodology 18
  - Projected Natural Gas Supply 19
  - Supply for United States 20
  - Supply for California 21
  - Environmental Issues Associated with Natural Gas Exploration and Production 21
- Natural Gas Price Forecast 24
  - Introduction 24
  - Price Forecasting Methodology 24
  - Wellhead Prices in North America 27
  - Gas Prices for Electricity Generators in the WECC Region 30
  - California Border Prices 31
  - Gas Prices for California Gas Utility Customers 32
- Natural Gas Infrastructure 33
  - Interstate Pipelines Serving California 33
  - Infrastructure Modeling Methodology 37
  - Natural Gas Infrastructure Assessment 38

Infrastructure within California 44
Natural Gas Storage 49
Winter 2002-2003 Natural Gas Storage Use 51

Chapter 3: Scenarios 55
Scenarios 55
Demand Scenarios 55
Supply Scenarios 62
Integrated Price and Supply Outlooks (IPSO) 68
LoIPSO 72
Basecase 72
HiIPSO 72
Conclusions 72

Chapter 4: Implications and Natural Gas Policy Issues 73
Introduction 73
Policy Goal 73
Background Context 73
Demand 73
Supplies 74
Infrastructure 74
Markets 75
Natural Gas Policy Issues 75
Overall Theme for Issues 75
A. Demand Issues 76
B. Supply Issues 76
C. Infrastructure Issues 77
D. Price/Market Issues 78
Conclusions 78

Acronyms 80

Glossary 81

Endnotes 83

Appendices
Appendix A: Energy Commission Resource Cost Curves
Appendix B: LNG Assumptions
Appendix C: Natural Gas Demand Projections
Appendix D: Transportation Costs, Capacities, Line Losses for NARG Model Corridors
Appendix E: End-Use Natural Gas Price Forecast by Sector
Appendix F: GDP Implicit Price Deflator

List of Figures

Figure 1a: Projected Natural Gas Flows for Year 2003 (TCF).. 8
Figure 1b: Projected Natural Gas Flows for Year 2013 (TCF) 9
Figure 2: U.S. Core and Non-core Natural Gas Demand (excluding California).................. 13
Figure 3: Natural Gas Demand in California, by Sector... 15
Figure 4: Natural Gas Consumption in the United States... 16
Figure 5: Natural Gas Price Components ($ per Mcf)... 25
Figure 6: Historical Wellhead Prices in the Lower 48 States –Monthly Averages 28
Figure 7: Historical and Projected Wellhead Prices in the Lower 48 States with High and Low Boundaries – Annual Averages 28
Figure 8: Projected Natural Gas Prices for Electricity Generators within the WECC Region31
Figure 9: Projected California Border Prices – Annual Averages... 32
Figure 10: Historical and Projected Utility End-Use Prices in California – Annual Averages 33
Figure 11: Western North American Natural Gas Pipeline 36
Figure 12: Southwest Corridor Interstate Pipeline Capacity Compared to Forecasted Flowing Supply 42
Figure 13: Kern River and PG&E GTN fInterstate Pipeline Capacity Compared to Forecasted Flowing Supply.. 45
Figure 14: Projected Natural Gas Demand Compared to PG&E's Supply Receiving Capacity 46
Figure 15: Projected Natural Gas Demand Compared to SoCal Gas's Supply Receiving Capacity 48
Figure 16: Natural Gas Storage Facilities Map.. 51
Figure 17: Northern California Storage Inventory.. 52
Figure 18: Southern California Storage Inventory.. 53
Figure 19: California Storage Inventory 53
Figure 20: U.S. Storage Inventory 54
Figure 21: Natural Gas Demand for Power Generation in California 56
Figure 22: Change in Gas Demand for Power Generation - High/Low Growth and DSM Cases 59
Figure 23: California Border Gas Price for the High/Low Growth and DSM Cases 60
Figure 24: Impact of Natural Gas Use in Transportation Sector 61

Figure 25: Impact of Natural Gas Use in Transportation Sector on CA System Wide Natural Gas Price 61
Figure 26: Market Share of Natural Gas / Oil in Lower 48 States 63
Figure 27: Impact of Low Resources on US Wide Gas Price 63
Figure 28: LNG Imports along US West Coast 65
Figure 29: LNG Imports along US Gulf and East Coast 65
Figure 30: Annual Average Price for LNG Imports 66
Figure 31: Annual Average Lower 48 States' Wellhead Price ($/MCF) 71
Figure 32: Natural Gas Production in US (TCF per year) 71

List of Tables

Table 2: Natural Gas Consumption in the Western United States 17
Table 3: Natural Gas Consumption in Canada and Mexico 18
Table 4: Projected Natural Gas Supplies for North America (in Tcf/yr) 19
Table 5: Projected Natural Gas Supplies for the United States (in Tcf/yr) 20
Table 6: Projected Natural Gas Supplies for California (in Tcf/yr) 21
Table 7: Projected Wellhead Prices – Annual Averages ($ per Mcf) 29
Table 8: Major Interstate Pipelines and Pipeline Capacity Serving California 37
Table 9: California Natural Gas Storage Facilities 51
Table 10: Comparative Growth Rates of Baseline and Scenario Forecast Assumptions .... Average Annual Growth Rate (%) 57
Table 11: Demand Changes over the Basecase 58
Table 12: Integrated Price and Supply Assessment Assumptions 70
Table 13: Annual Price Growth Rate, % 71

EXECUTIVE SUMMARY

Introduction

The California Energy Commission is required under Section 25310(a) of the California Public Resources Code to prepare a biennial forecast of natural gas demand, supplies, and prices for California over a 20-year period. This report is intended to assess the natural gas market trends, price and supply availability and infrastructure issues over the next decade (2003-2013). This report is in support of the *Electricity and Natural Gas Report* under the *Integrated Energy Policy Report* (IEPR). The IEPR is being prepared under the direction of the Ad Hoc Integrated Energy Policy Report Committee. Chapter 568 of the Statutes of 2002 (formerly SB 1389) mandates that the Energy Commission publish the IEPR and provide it to the Governor and California Legislature by November 1, 2003.

Electricity generation demand for natural gas is driving the growth in natural gas demand throughout the United States (U.S.). It is anticipated that supplies of natural gas will be sufficient but more costly. To accommodate growing demand in California and surrounding states, interstate natural gas pipeline infrastructure in the Southwest, Rocky Mountains, and Canada should be expanded to increase the amount of natural gas that can be transported to California. Based on current data, Southern California Gas Company (SoCal Gas) has adequate intrastate pipeline capacity to receive supplies arriving at the California border through 2013. However, the Energy Commission staff are concerned with the interstate capacity serving Southern California and the regulatory conditions affecting its usage. Increasing gas demand in the Arizona and New Mexico markets can absorb a significant amount of the natural gas flowing west from the San Juan and Permian basins. These markets can consume a significant amount of the supply that would otherwise serve Southern California. This potential bottleneck can be alleviated by expanding the interstate infrastructure serving the East-of-California markets.

Energy Commission staff expects that Pacific Gas and Electric Company (PG&E) will need to expand its pipeline capacity to access Canadian supplies by 2013 to meet the projected demand.

Assessment Methodology

This report was prepared in support of the Integrated Energy Policy Report. Accordingly, the assessment of the natural gas supply, demand, and price trends has been conducted by integrating the electricity market assessment and the natural gas and electricity demand assessments. The scenario analysis to investigate the potential impact of uncertainties in the energy markets also has been done by integrating the assumptions and conditions of both natural gas and electricity markets.

The Commission staff uses the North American Regional Natural Gas (NARG) Model as the principle tool to assess natural gas market fundamentals and generate the California border price forecast. Basic inputs to the NARG model include estimates of resource availability, proved reserves and expected appreciation, production costs, pipeline capacity and transportation costs, regional demand projections, and other parameters defining the market fundamentals. The basecase analysis resulting from the above inputs assumes average hydroelectricity and weather conditions and well-functioning competitive markets. Scenarios have been developed with alternative assumptions to test the impacts of varying conditions on price and supply availability and to investigate the inherent uncertainty in the natural gas market.

Key Findings and Conclusions

Demand Trends

The natural gas demand in the U.S. and Canada continues to grow, with power generation being the prime driver in all regions. Increasing demand for electricity coupled with limited new power generation through sources other than natural gas-fired technology emphasizes the importance of natural gas in meeting demand.

Based on Energy Commission staff analysis, California's overall demand for natural gas will grow approximately one percent per year between 2003 and 2013. The residential and commercial sectors' demand for natural gas is expected to grow at approximately one percent per year. The industrial demand growth is expected to be essentially flat, growing at 0.1 percent per year. The power generation sector's demand for natural gas is expected to grow the fastest in the state, at approximately 1.5 percent per year.

The recently constructed and proposed power plant development has primarily been natural gas-fired combined cycle facilities. If the proposed new plants are abandoned or delayed, natural gas demand will increase sooner because the older, less efficient plants will be needed to run more often.

California's future need for new power plants and the gas supply to serve those plants might decrease if power plants are constructed outside of California, and electricity can be imported from out-of-state facilities at competitive prices.

Supply Trends

Between 2003 and 2013, supplies of natural gas will be sufficient but more costly. The demand for natural gas is increasing throughout North America, and supplies are not as plentiful as expected earlier. As a consequence, the U.S. will likely become increasingly reliant on natural gas from Canadian and liquefied natural gas (LNG) imports, while developing domestic economical "unconventional" sources of natural gas to meet growing demand. Under tight supply conditions, some customers might get priced out of the natural gas market, leading to condition referred to as "demand destruction".

In some regions of the U.S., industrial and power generation customers with dual-fuel capability will likely switch to another fuel, such as oil during high natural gas price conditions. The Energy Commission staff does not expect any appreciable level of fuel switching in California. In the long-term, LNG projects proposed for the East Coast as well as for the West Coast could potentially provide a needed supply source to enhance U.S. reliability if these projects are permitted. The developers of these LNG projects expect to begin serving the West Coast market by 2007 time frame.

Through 2013, the Southwest will remain the state's major natural gas resource region. However, California will increase its gas imports from the Rocky Mountain region and Canada. Expansion of the Kern River pipeline from the Rocky Mountain, completed in May 2003, provides the needed increase in pipeline capacity to serve the state.

Price Projections

Prices for natural gas will likely rise faster than inflation due to growth in gas demand and the expense of developing new gas wells and pipeline capacity.

Electricity generators in the Western Energy Coordinating Council (WECC) region will likely find the lowest-cost natural gas along the PG&E-owned Gas Transmission Northwest pipeline corridor in the Pacific Northwest (which delivers Canadian supplies), and the Kern River pipeline corridor (which connects California to Rocky Mountain gas supplies). Electricity generators who receive gas-delivery service from PG&E, SoCal Gas, and San Diego Gas and Electric Company (SDG&E) are expected to pay the highest prices for natural gas.

California's two largest natural gas utilities, PG&E and SoCal Gas, will have similar California border prices after 2007. However, PG&E's prices are expected to be slightly less expensive than SoCal Gas's prices. System-average prices for all customers of these utilities will probably range between $4 to $6 per thousand cubic feet of natural gas (Mcf), in constant 2000 dollars, between 2003 and 2013. Gas-fired generators that obtain gas from California gas utilities are projected to pay more than $4 per Mcf (in constant 2000 dollars) by 2013.

Infrastructure Trends

New gas-fired power plants in the Western U.S. are increasing gas demand and, in turn, triggering the need for new investments in interstate pipeline projects. The gas flow patterns in the basecase indicate that additional pipeline capacity will be needed to meet growing electricity generator demand in southern Nevada, Arizona, and New Mexico. The San Juan and Rocky Mountain basins will be the primary supply basins of choice.

Within California, the Commission staff predicts that PG&E will need additional receiving capacity or storage after 2006. SoCal Gas recently completed major infrastructure projects with a total pipeline capacity addition of 375 million cubic feet per day. As a result, under average conditions, SoCal Gas has adequate intrastate slack capacity for its service territory through 2013.

Three recently-completed interstate pipeline companies' projects (the Kern River Expansion, the Southern Trails and the North Baja Project) coming into the state and PG&E's expansion of it's Line 401 by 180 mmgd will provide significant benefits to California by improving the ability to move the gas supplies to regional demand centers. In addition, the Kern River Lateral and the El Paso Lateral, to be completed by July 2004, will interconnect a number of main pipelines and should provide additional flexibility.

Natural Gas Storage

Natural gas storage is important as it provides flexibility for the market to balance supply and demand. Storage also provides a stable and reliable supply. Finally, use of natural gas from storage offers supplies as a buffer against volatile price movements in the market place.

California today has about 243 Bcf of storage capacity. In southern California, all storage is owned by the local gas utility, SoCalGas while SDG&E purchases storage services from SoCalGas. In northern California, storage facilities are owned by both the local gas utility, PG&E, and by two private storage facilities, Wild Goose Storage and Lodi Gas Storage.

The gas utilities mainly purchase natural gas for storage to meet the needs of the Core market sector. Based on specific rules, the Utilities ensure that adequate gas is stored in their facilities to meet the high demand during the winter heating season. The critical issue regarding storage is with its use in the Noncore sector. While customers will get more reliable service if gas is stored, the economics of this operation is not always seen as beneficial by noncore customers.

The major questions arising are whether to bundle storage services for the noncore custoemrs in addition to the current practice for core customers; how should storage related costs be allocated if the utility companies should provide enhanced storage services to the noncore customers. Finally, the question arising on the physical aspects of the storage facilities are whether the current storage capacity and locations are adequate for the state operations, should additional capacity be added in either of the utility service areas, and should the addition be done by private or the utility companies? This Market Assessment Report begins to address these questions

Scenarios

A total of eleven scenarios were developed to study the impact of a variety of market uncertainties on natural gas prices and supply availability. This report provides the results of this analysis. The scenarios studied are generally referred to as:

1. Basecase
2. Dry hydro

3. High economic growth
4. Low economic growth
5. High PGC impacts
6. Low PGC impacts
7. Transportation demand
8. Low natural gas supply
9. LNG to West Coast
10. Integrated Low gas price scenario
11. Integrated High gas price scenario

The scenario analysis conducted indicates that changes in natural gas demand, due to factors such as low precipitation conditions or moderate slowing or speeding up of the state's economy, do not appear to affect the long-term trends in the natural gas market. It is entirely possible that these conditions can cause seasonal disruptions, increase volatility of prices in the spot market, or create supply tightness on peak days.

Policy Implications

The State of California's long-term goal for natural gas is to ensure a reliable supply of natural gas, sufficient to meet California's demand, at reasonable and stable prices, and with acceptable environmental impacts and market risk. The two main policy themes associated with achieving this goal include whether or not:

- California is managing all possible challenges that might prevent it from continually achieving its natural gas energy goal adequately; and
- California is actively pursuing all reasonable actions to achieve an optimum natural gas energy goal.

The Energy Commission staff assumes that participants in the natural gas industry will act in a reasonable and rational manner and make their decisions on infrastructure investment and operation in a manner consistent with fundamental economic principles. Staff also assumes that short-term economic dislocations will be resolved and not affect long-term trends and that regulatory policies and decisions will guide this development in a balanced and efficient manner.

The Energy Commission staff have identified several issues that need to be addressed in the demand, supply, infrastructure, and price/market areas. While discussion is needed on all of them, staff have also highlighted three key issues needing immediate action. These are: risk analysis, access to new supplies, including LNG, and natural gas storage. Staff proposes to investigate these issues further and report on it findings in the next natural gas outlook.

CHAPTER 1: INTRODUCTION

The Future of the Natural Gas Market

California's challenge for the future is designing a natural gas market that will provide reliable supply to all consumers. The natural gas market should also ensure that consumers can operate in a less uncertain environment when planning for energy needs and reasonably priced fuel supplies. Affordability and reliability of natural gas will require a comprehensive analysis of the market structure and a re-evaluation of supply, pricing, infrastructure, and market issues.

The Commission staff reviews and analyzes a wide range of parameters that influence the natural gas market in California as well as those parameters outside of California markets that potentially influence the in-state market. The Commission staff is focusing its attention on the following issues:

- Evaluation of supply and demand balance over the short term and over a ten-year period
- Evaluation of the influences and impacts of storage operations and capacity in the seasonal market balance
- Evaluation of pipeline capacity, and assessment of regional infrastructure improvements on reliability
- Evaluation of natural gas demand from power generators in the state, and the impacts of the Western Electricity Coordinating Council (WECC) area-wide demand for natural gas on prices and availability in California
- Assessment of impacts resulting from changes in demand trends on natural gas prices and supply
- Evaluation of prices and supplies resulting from weather, economic, and regulation changes in the gas market.

The Energy Commission will analyze the integrated energy market by considering the relationship of the different energy resources used in the state. This *Preliminary Natural Gas Market Assessment* report will assist the Commission in developing policies for the *Integrated Energy Policy Report (IEPR)*, a comprehensive study of integrated energy resources in the future. The IEPR is scheduled to be published by November 1, 2003.

Past and Current Trends in the Natural Gas Market

Natural gas is an important fuel source in California, and the market is evolving continuously with the changing environment. During the late 1980s, the state experienced significant natural gas curtailment due to increased demand and a constrained pipeline capacity to receive gas supplies at the state's border. As a result, multiple proposals were made to expand the interstate pipeline capacity to California. The Energy Commission, at that time, emphasized its policy on letting the market forces decide on which pipelines should be expanded. Based on this policy and market decisions, in the early 1990s, the PG&E-GTN pipeline from Canada to the State's border was expanded and the new Kern River and the Mojave pipelines were constructed. The addition of the three major interstate pipelines provided the price and supply reliability needed in the state. Throughout the 1990s, California benefited from ample pipeline capacity and the resulting natural gas prices in the state were stable and affordable. Supplies were reliable to the extent that the utility companies confidently offered guaranteed supplies without any curtailments. Since then the natural gas market has experienced very significant market and regulatory changes. These include natural gas and electricity market restructuring, a significant increase in natural gas usage by power generators in California and much of the U.S., and an increase in natural gas consumption in all other sectors.

Starting with summer of 2000, the natural gas market trends have significantly changed. Both the U.S. and Canada, over the past three years, have seen a very volatile natural gas market resulting from a combination of long-term supply and capacity related issues and short-term storage capacity, weather, and rainfall/snowpack conditions. These factors contributed to an energy crisis in California and the western U.S., along with some market participants who manipulated the electricity and natural gas data reporting and trading activity.

The natural gas market has been extremely volatile since summer 2000. Natural gas prices have fluctuated significantly on a day-today basis as well as with erratic monthly and seasonal price averages. Prices spiked to alarming highs during the winter of 2000-2001. That was followed by relatively lower prices during August 2001 to almost end of 2002. The winter of 2002-2003 started with relatively lower prices and high inventories in natural gas storage facilities. However, the extreme and prolonged cold in the eastern U.S. depleted much of the natural gas in storage and caused significant price swings in the northeastern markets. These swings affected natural gas prices in California, but not to the same extent as in the Northeastern states.

Energy uncertainties over the past three years resulted in additional changes to the market place. High natural gas prices have eroded consumption, especially in the industrial sector. The number of power plants built in the state (and in the WECC region) has increased and consequently, the long-term demand for gas in the power generation sector in the state has increased. Power generation continues to be the lead driver for growth in demand for natural gas in the state.

The Energy Crisis

Energy uncertainties over the past three years have resulted in changes to the market place and a destabilization of past trends. High natural gas prices have reduced consumption, especially in the industrial sector. Uncertainties in the electricity market have increased the number of power plants built in the state and consequently the demand for gas in the power generation sector in the state. The California energy crisis during the winter of 2000-2001 resulted in high prices, especially at the southern California/Mexican border. However, following this energy crisis, the natural gas market has stabilized due to infrastructure upgrades as well as consumer behavior.

The capacity to transport gas to the state via interstate pipelines has increased. In addition, the ability to transport supply inside the state to all consumers has increased. Changes in storage capacity will also play a significant role in moderating the price volatility in California. Since the energy crisis, storage capacity or the ability to withdraw gas out of storage has increased in southern California as a result of actions taken by SoCal Gas. In northern California, two private storage facilities have sprung into operation providing the much needed supply buffer required under peak conditions. Consumers' use leads to daily balancing, and the need to meet demands on very hot or very cold days.

CHAPTER 2: BASECASE

Introduction

This chapter provides information on natural gas demand, supply, price, and infrastructure used in the Energy Commission's assessment of the natural gas market. This assessment serves as the basecase forecast of natural gas price and supply availability. The assumptions underlying this forecast stem from the expectation that market outlook will be on a 'business as usual' trend throughout the assessment period. The basecase assessment is done on an annual average conditions for the various price and flows analyzed. Hence the basecase represents a long-term outlook and does not reflect the short-term market conditions such as peaking demand condition, seasonal cycles and operation of storage facilities. The long-term perspective provides the Governor, Legislature and industry with trends in market that can be anticipated based on the drivers assumed in the analysis.

The assumptions under the basecase are described in each of the following sections in this chapter. The natural gas price and supply assessment is conducted by coordinating this analysis with the demand assessment and the electricity infrastructure assessment efforts, thus providing an analysis to support the integrated energy policy analysis that is underway at the Commission.

NARG Model Assessment Methodology

The Energy Commission staff has used the North American Regional Gas (NARG) model as its principal assessment tool since 1989. This general equilibrium model predicts the quantities and prices of natural gas needed to balance supply and demand throughout North America over a 45-year forecast horizon in five-year increments. The analysis in this report focuses on the first ten years of the forecast.

The NARG model incorporates natural gas demand data from the contiguous United States, Alaska, Canada, and portions of Mexico. In addition to the demand data, the NARG model also incorporates information on resource availability, production costs, pipeline capacity, and pipeline transportation costs.

The latest version of the NARG model includes:

- 20 demand regions,
- 18 North American supply regions, and
- Four LNG import locations along the Atlantic seaboard and Gulf Coast.

Demand Regions

Demand regions each contain three end-use consumer classes: core, noncore, and power generation (see sidebar). The demand regions largely correspond to census regions defined by the U.S. Department of Energy. Refer to the Demand Section of this chapter for details on natural gas demand.

NARG Model Terms and Input Variables

Demand Regions

Core Customers – rely solely on natural gas and cannot switch to an alternate fuel.

Non-core Customers – can switch to an alternate fuel if the price of natural gas exceeds a pre-determined cost.

Power Generation Customers – are not included in core or noncore.

Pipeline Corridors

Each assigned a natural gas transport capacity and cost that can vary with use and/or new pipeline infrastructure.

Supply Regions

Conventional and unconventional resources (coalbed methane, tight sands, and shale) are split into proved and potential reserves:

Proved Reserves – require only the outlay of operation and maintenance costs.

Potential Reserves – require capital costs and operation and maintenance costs.

Pipeline Corridors

The NARG model configures each pipeline or pipeline corridor by designating a transport capacity and cost. Corrections are used to account for penalties and discounts. For example, when natural gas flows exceed the listed capacity, the model applies a penalty to the cost of transportation to account for costs incurred in expanding the pipeline capacity. Conversely, the model applies discounts when flows on pipeline or pipeline corridors fall below specified levels to account for the competitive forces that historically affect secondary markets. **Figures 1a (2003) and Figure 1b (2013)** provide a schematic of the regions within the model along with the projected gas flows along pipeline corridors.

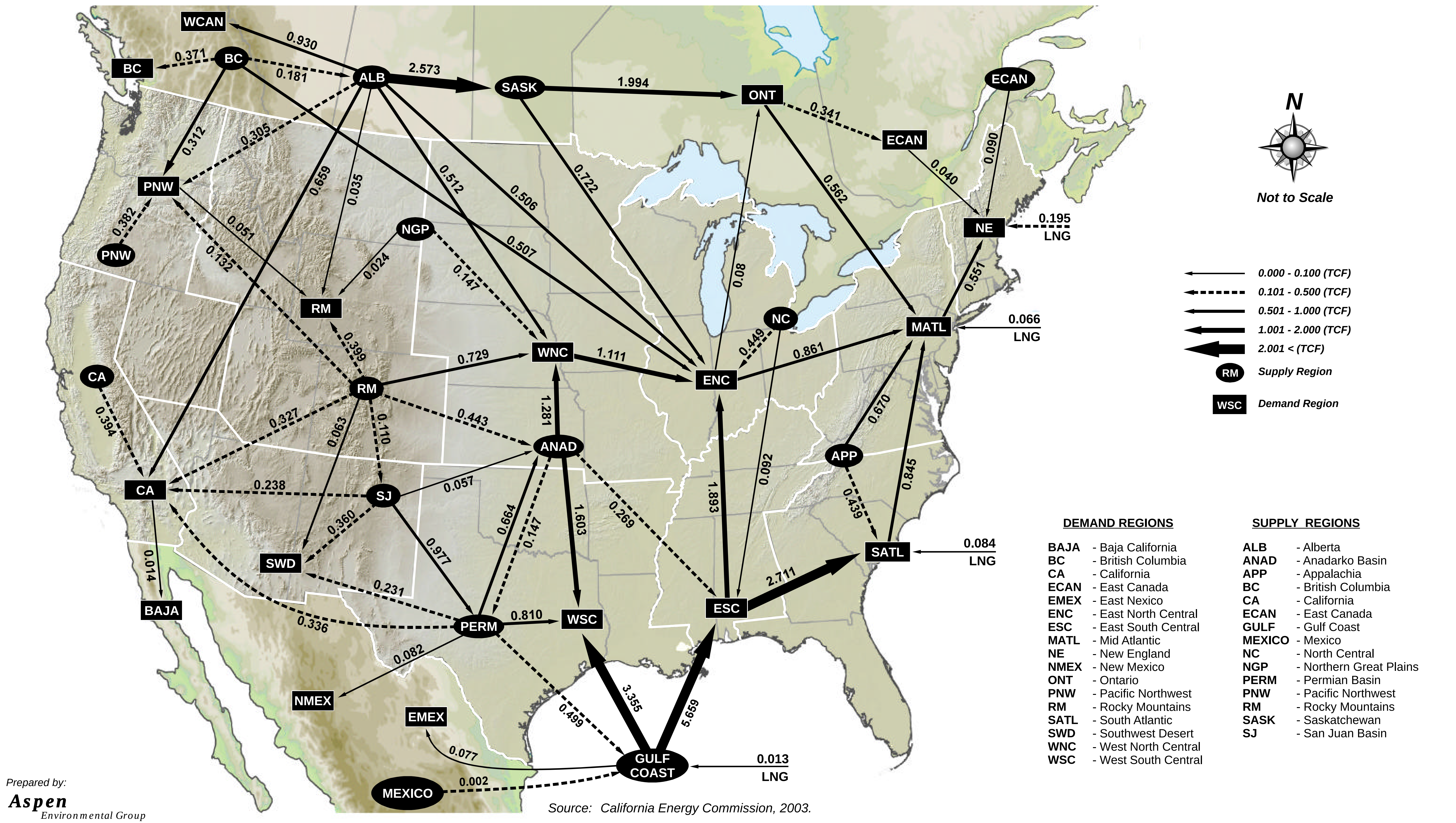
Supply Regions

The NARG model has 18 specific supply regions. Each supply region contains multiple natural gas resources, reflecting different types of conventional and unconventional geological formations. Basic inputs to the NARG model include United States Geological Survey (USGS) estimates of resource availability and production costs. Other parameters are used to simulate long-term market conditions.

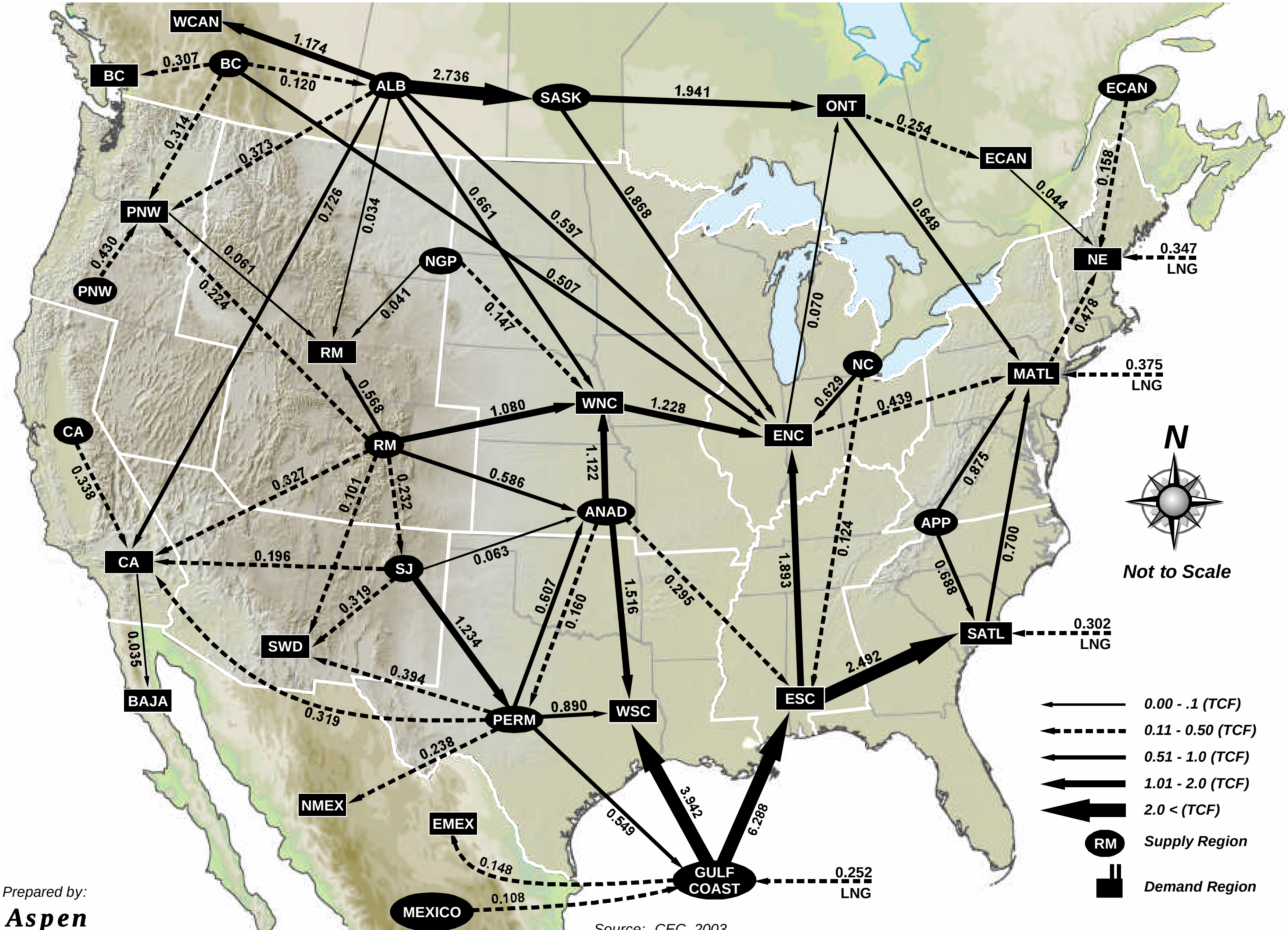
The resource base consists of two categories of reserves: proved and potential. The model assumes that proved reserves are produced first. As it seeks greater amounts of natural gas to satisfy demand requirements, the model moves potential reserves to the proved category. Cost curves in the model determine the associated cost of developing potential reserves. Technology enhancement parameters lower the cost at which potential reserves become proved. Using these terms, the NARG model can determine which reserves will be produced and the associated costs of the production.

Experience shows that more natural gas is recovered from known producing areas than originally anticipated, thus proved reserves tend to increase over time. The amount of natural gas that is eventually produced from each of the basins depends on a variety of factors.

PROJECTED NATURAL GAS FLOWS FOR YEAR 2003 (TCF)



PROJECTED NATURAL GAS FLOWS FOR YEAR 201 3 (TCF)



Prepared by:

Aspen Environmental Group

Source: CEC, 2003.

The assessment of these factors improves as more information is available to producers during the process of developing and producing gas from the reserves. Thus, each year, producers reassess the basin quality and quantity of natural gas contained within. The amount of gas that can be produced from these resources depends on well conditions, new technologies in production, drilling and identification of sources for new wells. Specifically, several factors lead to the phenomenon of expanding proved reserves, including:

- Technology improvements in recovery and production methods,
- Increased drilling sites (*i.e.*, in-fill drilling) tapping into remaining pockets of natural gas, and
- Availability of refined and/or better methods to assess the amount of recoverable gas in the proved resource base.

The economics of producing resources changes as new methods that are less expensive and more reliable than historical methods result in increasing the reserve size. Historically, the reserve appreciation has almost always resulted in increasing the proven reserves or amount of gas that can be produced. This phenomenon is captured in the NARG model by adjusting the reserve appreciation factor that reflects the gas industry's experience in recovering more natural gas than originally estimated. In the model the reserve appreciation factor for each resource ranges from 0.5 to 2.2 percent depending on the type and maturity of each resource.

NARG Model Structure and Assumptions

The level of detail in the NARG model has evolved over time. As new information becomes available, the Commission staff updates various parameters within the model. Commission staff continually tracks the resource base, pipeline infrastructure, and makeup of demand sectors throughout the continent.

The model's flexibility allows the staff to add or delete pipelines, supply regions, and demand regions. The user can adjust the capacity of any pipeline at a specific time in the future, or alternatively the model can adjust capacity as additions become economically viable. Transportation rates and the amount of fuel used for pipeline compressors can also be modified by time period.

Demand assumptions for each customer class – core, noncore, and power generation – can also be modified to make demand elastic or inelastic to price. Due to time constraints staff was unable to incorporate a price response function for demand. While the core customer class relies solely on natural gas, the noncore and power generation classes outside of California can switch to an alternative fuel if the price differentials are sufficient to justify the switch.

After entering all necessary parameter and assumption data, the NARG model solves for equilibrium prices and gas flows in all regions in all time periods.

Natural Gas Demand

Natural gas demand throughout North America affects natural gas supplies and prices in California. The natural gas demand projections for the United States, California, and Canada and Mexico were used to forecast natural gas consumption in these regions during the period of 2003 to 2013.

Modeling Assumptions and Data Sources

The Energy Commission staff used the North American Regional Gas (NARG) model as its principal assessment tool to determine natural gas consumption. To do so, the NARG model incorporates natural gas demand data from the contiguous United States, Alaska, Canada, and portions of Mexico.

In the past, Energy Commission staff obtained natural gas demand data from the Gas Research Institute (GRI) *Baseline Projection Data Book*; however, GRI no longer produces that publication. For this report, the Energy Commission staff utilized demand data from the Department of Energy, Energy Information Administration's (EIA) *Annual Energy Outlook 2002* (AEO 2002), with the following exceptions:

- California's natural gas demand data were developed by the Energy Commission's Demand Analysis Office and obtained from the *California Energy Demand Forecast 2003-2013* report;
- The Energy Commission's Electricity Analysis Office provided information on natural gas demand for electricity generation within the Western Electricity Coordinating Council (WECC), including California; and
- The Canadian natural gas demand data are based on 2001 data from the Canadian Energy Research Institute (CERI).

Once the projected natural gas demand and supplies are incorporated into the NARG model, the model solves for the equilibrium price and quantities consumed over the forecast period. The level of consumption, as well as where that consumption will take place, is an important tool in determining the need for additional natural gas infrastructure.

Natural Gas Demand Assumptions

This section describes the demand inputs to the NARG model for the United States, California, Canada, and Mexico. In summary, while the states demand for natural gas in the electricity generation sector grows between one to two percent per year, national electricity generation demand will grow at nearly 5 percent per year. Growth in the residential commercial and industrial sectors in the US and in California is relatively flat over the assessment period.

United States

The Energy Commission staff classifies natural gas demand data for the U.S. into one of three sectors according to the consumer: core, non-core, and power generation. A description of each sector is provided in the side bar, to the right. For the non-core and power generation demand sectors, oil demand is included because natural gas can be substituted for oil as a fuel source. In addition, the Energy Commission staff uses oil demand as a proxy for all alternative fuel sources for which natural gas could be used as a substitute, such as coal, distillates, or residual fuels.

In the non-core sector, staff estimates that 25 percent of the commercial energy demand currently projected to be met by oil could switch to natural gas. Similar reasoning is applied to industrial oil demand; however, it is assumed that the percentage of industrial oil demand potentially met by natural gas increases over time. Staff only applies this rationale to non-core demand in regions where fuel switching is permitted.

Demand Sector Classifications

- **Core demand** consists of residential, commercial, transportation, and one-half of the industrial natural gas demand. Core customers are totally dependent on natural gas and cannot use alternative fuels, such as petroleum, in place of natural gas;
- **Non-core demand** consists of the remaining half of the industrial natural gas demand, 25 percent of commercial oil demand, and increasing amounts of industrial oil demand (20 percent in 2002, 30 percent in 2007, 40 percent in 2012, and 50 percent thereafter); and
- **Power generation demand** consists of all the natural gas demanded by electricity generation. For regions where petroleum fuel is used for power generation, oil demand is included in this category.

The inclusion of oil demand in the power generation sector varies depending on the geographic region. Based on a literature survey, the Energy Commission staff has determined that only four of the eleven demand regions in the U.S. consume significant quantities of heavy oil or distillates for power generation. These regions are the West North Central, West South Central, Mid Atlantic, and South Atlantic. Accordingly, staff included all of the oil demand for electricity generation in deriving total demand for these regions. Conversely, staff assumed the remaining regions are dependent on natural gas for all incremental power generation as projected by the EIA. It should be noted that EIA estimates that some of these regions will continue to build electricity generation facilities that use fuels other than natural gas, such as coal.

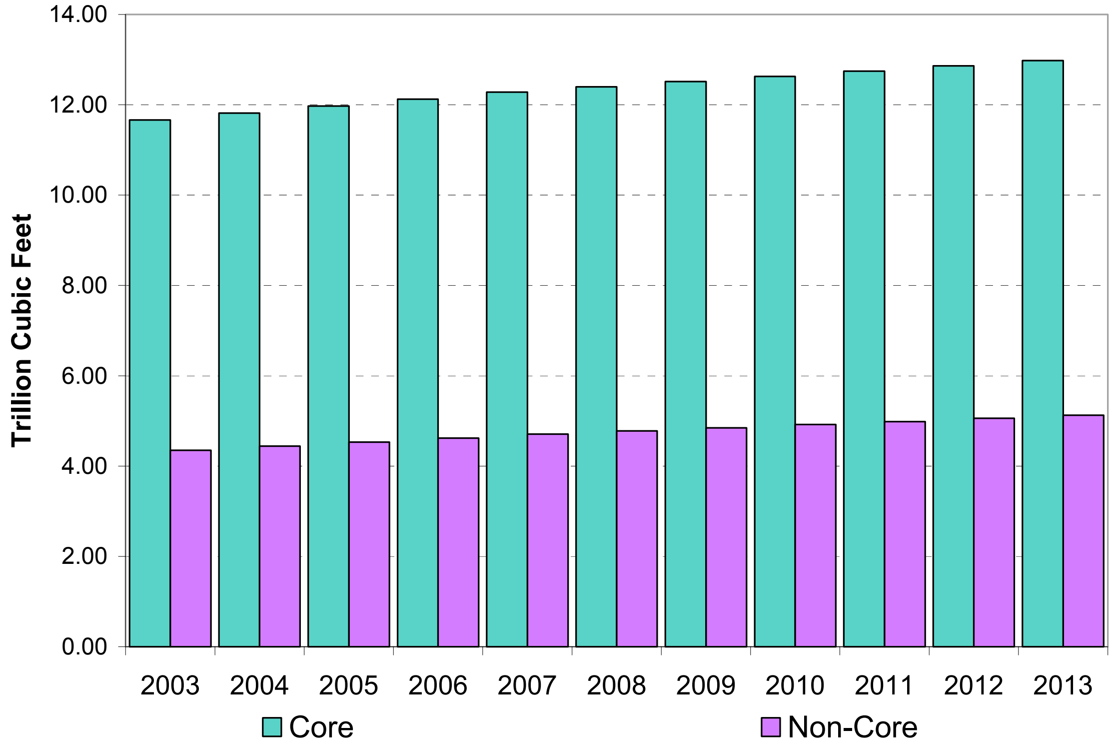
Core and Non-core Natural Gas Demand

Figure 2 shows the core and non-core natural gas demand for the U.S. (excluding California). According to EIA's *Annual Energy Outlook 2002*, natural gas demand in the U.S. (excluding California) will grow as follows:

- **Core demand** will increase from 11.67 trillion cubic feet (Tcf) in 2003 to 12.98 Tcf in 2013, an annual growth rate of 1.1 percent.

- **Non-core demand** will increase at an annual rate of 1.7 percent between 2003 and 2013, from 4.35 Tcf to 5.12.

Figure 2: U.S. Core and Non-core Natural Gas Demand (excluding California)
Source: Department of Energy, EIA



Natural Gas Demand for Power Generation

Natural gas demand for electricity generation represents the fastest growing sector, according to both the EIA's projection for outside the WECC, and staff's projection for within the WECC. The EIA estimates that from 2003 to 2013, gas demand for power generation will grow at an annual rate of 4.6 percent, compared to 1.2 percent for all other sectors. In fact, EIA projects that by 2020, electricity generators will account for 55 percent of total natural gas consumption in the United States. Gas demand for power generation could eclipse all other sectors even sooner, considering that EIA tallies natural gas demand for cogeneration as industrial, or non-core, demand rather than with the power generation sector as in the Energy Commission's estimates.

The natural gas demand for electricity generation in the WECC states surrounding California will increase at an annual rate of 6.6 percent over the next decade per analysis done by the EAO and reported in the Electricity Infrastructure Assessments Report. Specifically, gas demand for power generation will increase by:

- 7.4 percent per year in the Desert Southwest,
- 8.5 percent per year in the Rocky Mountain region, and

- 4.0 percent per year in the Pacific Northwest.

Table 1 shows the growth in natural gas demand for power generation in the WECC states surrounding California, compared to the rest of the United States (excluding California).

Table 1: Natural Gas Demand for Power Generation

	Trillion Cubic Feet 2003	Trillion Cubic Feet 2013	Annual Growth Rate (2003-2013)
Pacific Northwest	0.18	0.27	3.96%
Southwest Desert	0.26	0.53	7.43%
Rocky Mountains	0.10	0.23	8.46%
Western States (excluding California)	0.54	1.03	6.60%
United States (non WECC)	4.18	6.53	4.57%

Source: California Energy Commission and Department of Energy, Energy Information Administration

California's Natural Gas Demand

The Energy Commission's Demand Analysis Office forecasts that the combined, core and non-core natural gas demand will grow at a rate of 0.6 percent per year in California from 2003 to 2013. This represents less than half of the annual rate by which total U.S. core and non-core natural gas demand is projected to grow during the same period. From 2003 to 2013, natural gas demand in California will increase as follows:

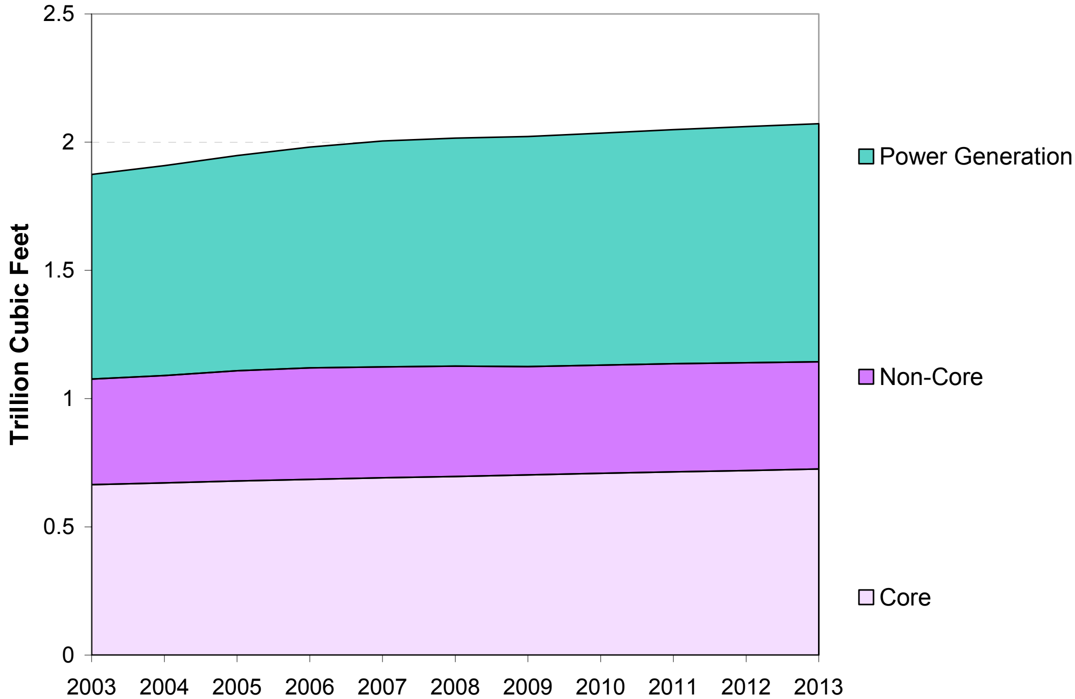
- **Core demand** will increase from 0.66 to 0.73 Tcf, a rate of 0.9 percent per year,
- **Non-core demand** will increase from 0.74 to 0.77 Tcf, which is an annual growth rate of only 0.4 percent.

The Demand Analysis Office's natural gas demand forecast includes the impacts of natural gas energy efficiency programs, and assumes that the current levels of funding for utility energy efficiency programs will continue through 2011, as authorized by the California Legislature.

Data provided by the Energy Commission's Electricity Analysis Office show that gas demand for electricity generation remains the fastest growing segment of California's natural gas demand. Over the next ten years, natural gas demand for power generation will grow from 0.80 to 0.93 Tcf per year, yielding an annual growth rate of 1.5 percent per year. **Figure 3** illustrates natural gas demand in California, by sector.

Figure 3: Natural Gas Demand in California, by Sector

Source: California Energy Commission



Canada and Mexico

The Canadian demand inputs for NARG are based on 2001 data from the Canadian Energy Research Institute (CERI). The composition of the Canadian demand data is similar to that of the U.S., except it is broken into only core and non-core sectors. For Canada, power generation demand for natural gas is included within the non-core demand sector. CERI projects that Canadian gas demand will grow 2.2 percent per year over the next decade, increasing from 2.15 to 2.32 Tcf in the core sector, and from 1.66 to 2.40 Tcf in the non-core sector.

Mexican natural gas demand estimates include only three regions adjacent to the U.S., referred to as North, East, and Baja. Demand data for the North and East regions were derived using actual consumption data published by the EIA in its *Natural Gas Imports and Exports* report. The staff then increased this consumption by one percent annually to derive its estimates for the North and East regions. The demand estimate for the Baja region is based on the natural gas demand for power plants, provided by the Energy Commission's Electricity Analysis Office.

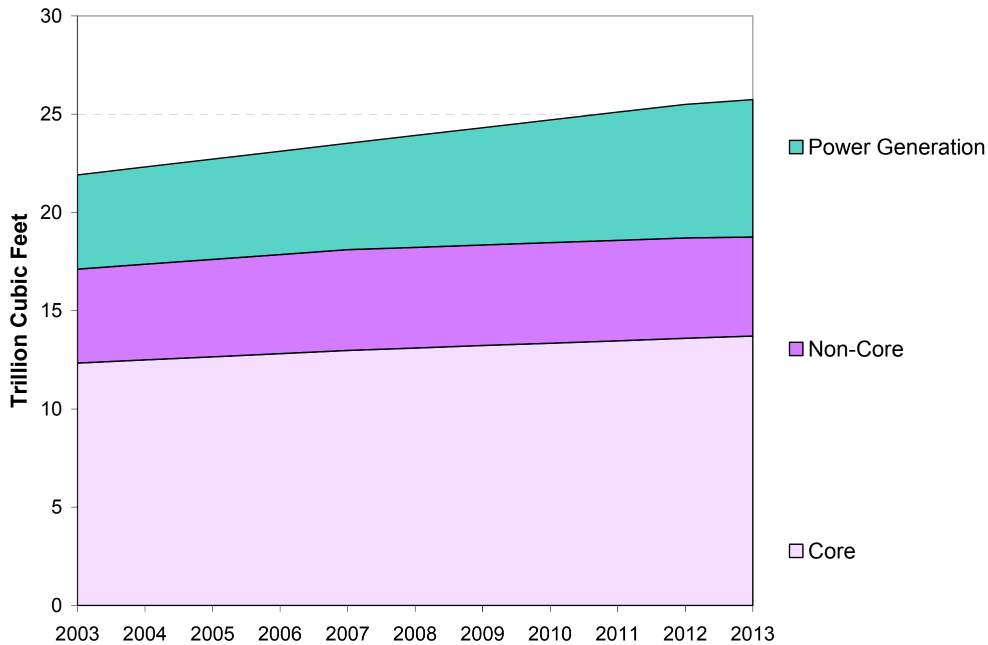
Natural Gas Consumption in the Basecase

This section provides the projected natural gas consumption for the United States, California, Canada and Mexico (border region) based on the NARG modeling results. The consumption levels are a result of the model analysis and are based on the assumptions made in the NARG model and the demand estimates input to the model.

United States

Figure 4 depicts U.S. natural gas consumption for the next decade, by sector. According to the basecase, U.S. natural gas consumption will grow 1.6 percent over the next decade. The largest growth will occur in the power generation sector, which is projected to grow at an annual rate of 3.9 percent. Core and non-core sector natural gas consumption will increase annually by 1.0 percent and 0.5 percent, respectively.

Figure 4: Natural Gas Consumption in the United States
Source: California Energy Commission



California and Western United States

In California, fuel substitution is only permitted in emergency situations, and hence there is no alternative fuel available for the industrial and power generation sectors. Therefore, natural gas consumption and demand estimates for California will be the same. All demand in the state must be met by natural gas.

The current basecase projection for natural gas consumption is lower than the projection contained in the Energy Commission's December 2002 Staff Paper entitled *Natural Gas Supply and Infrastructure Assessment*. In that report, consumption was projected to grow at an annual rate of 1.9 percent; 1.3 percent for core, 1.3 percent for non-core, and 3.9 for power generation. Possible explanations for why the two forecasts differ include:

- Differences in methodology between the EIA, the primary source of U.S. demand data for this *Natural Gas Market Outlook Report*, and GRI, the primary source for the 2002 *Natural Gas Supply and Infrastructure Assessment* Staff Paper;

- The EIA's *Annual Energy Outlook 2002* might reflect demand destruction that occurred as a result of the high natural gas prices in 2000 and 2001. The 2002 Energy Commission staff report used data from the 2000 edition of GRI's *Baseline Projection Data Book,* which does not reflect the same information; and
- Staff limited economic fuel switching to four demand regions, whereas in previous reports fuel switching was allowed in all demand regions other than California.

Natural gas demand in the states surrounding California is projected to grow at a faster annual rate than the U.S. as a whole, driven primarily by natural gas consumption for electricity generation. However, as was the case with the U.S., the projected growth rates are not as robust as those forecasted in the Energy Commission's December 2002 staff report. The largest decline in projected consumption growth occurred in the Pacific Northwest where the projected consumption by 2013 in the basecase is almost 50 percent lower than the Energy Commission's December 2002 projection.

According to the Energy Commission's Electricity Analysis Office, this drop in consumption is attributable to the permanent decline of the aluminum smelting industry in the Pacific Northwest. This fundamental change in the industrial sector in the Pacific Northwest resulted in a significant reduction in the electricity load growth projections for the region, reducing the amount of natural gas needed to fuel electricity generators. The lower basecase consumption projections for the Southwest Desert and Rocky Mountain regions reflect generally lower electricity demand forecasts, as well. **Table 2** provides the projected demand in the Western United States, as well as the forecast consumption growth rates from the Energy Commission's December 2002 staff report.

Table 2: Natural Gas Consumption in the Western United States

	2003		2008		2013		Annual Growth Rate (2003-2013)	
	12/02 Report	Current Report	12/02 Report	Current Report	12/02 Report	Current Report	12/02 Report	Current Report
Pacific Northwest								
- Electricity generation	0.17	0.18	0.27	0.23	0.42	0.27	9.15%	3.96%
- All other sectors	0.46	0.42	0.50	0.45	0.49	0.48	0.51%	1.51%
Subtotal	0.63	0.60	0.77	0.67	0.90	0.75	3.56%	2.31%
Southwest Desert								
- Electricity generation	0.32	0.39	0.55	0.62	0.66	0.62	7.46%	4.76%
- All other sectors	0.30	0.26	0.35	0.29	0.39	0.31	2.84%	1.83%
Subtotal	0.62	0.65	0.90	0.91	1.05	0.93	5.47%	3.67%
Rocky Mountains								
- Electricity generation	0.08	0.10	0.15	0.20	0.23	0.22	11.38%	8.81%
- All other sectors	0.61	0.54	0.70	0.59	0.77	0.64	2.39%	1.80%
Subtotal	0.69	0.63	0.85	0.78	1.00	0.86	3.82%	3.17%
California								
- Electricity generation	0.66	0.80	0.74	0.89	0.82	0.93	2.22%	1.54%
- All other sectors	1.61	1.40	1.79	1.46	1.94	1.50	1.87%	0.67%
Subtotal	2.27	2.20	2.52	2.35	2.76	2.43	1.98%	0.99%
Western States								
- Electricity generation	1.23	1.46	1.70	1.93	2.12	2.03	5.60%	3.36%
- All other sectors	2.98	2.61	3.33	2.78	3.59	2.93	1.88%	1.16%
TOTAL	4.21	4.07	5.04	4.71	5.71	4.97	3.10%	2.00%

Source: California Energy Commission

Canada and Mexico

In the basecase, Energy Commission staff projects that natural gas consumption in Canada will be virtually flat over the next decade, with gas consumption in the non-core sector actually declining over the same period. During that time, Canada's incremental demand will be met by alternative fuel sources. Natural gas consumption in Northern Mexico is projected to grow at a rate of 6.4 percent per year, driven mainly by gas demand for electricity generation. Projected Canadian and Mexican natural gas consumption is shown in **Table 3**.

Table 3: Natural Gas Consumption in Canada and Mexico

		Trillion Cubic Feet 2003	2008	2013	Annual Growth Rate (2003-2013)
Canada	CORE	1.7286	1.7718	1.822	0.53%
	NON-CORE	1.026	0.996	0.9518	-0.75%
	TOTAL	2.7546	2.7678	2.7738	0.07%
Mexico	BAJA	0.0516	0.1256	0.1562	11.71%
	NORTH CENTRAL	0.083	0.0878	0.092	1.03%
	NORTH EASTERN	0.0774	0.1404	0.1476	6.67%
	TOTAL	0.212	0.3538	0.3958	6.44%

Source: California Energy Commission

Natural Gas Supply

This section assesses the adequacy of natural gas supply as it relates to California's demand. The first part of this section describes the methodology for assessing the natural gas supply sources serving North America, the United States, and California. The second part concludes that North America continues to have sufficient natural gas supplies to meet its predicted demand. Forecasted production in the lower 48 states will reach 21.8 Tcf/yr of natural gas by 2013. Staff predicts that the future supplies of natural gas will satisfy projected demand, but at a higher cost.

Supply Assessment Methodology

As described in the Introduction to this chapter, the Commission staff used the NARG computer model to predict the natural gas supplies in North America, United States, and California between 2003 and 2013. In addition to the general assumptions made in the model and described earlier, some of the specific supply assumptions used in the NARG model as described below.

The following inputs to the model were updated or modified for the supply analysis. Staff added the following infrastructure to the NARG model for this supply analysis, based on updated information:

- Added capacity to account for the east-of-California portion of El Paso's All American interstate pipeline;

- Added El Paso's in-State portion of the All American pipeline – Line 1903, a lateral connection from Daggett to Blythe, California; and
- Adjusted model parameters so that fuel switching occurs in only four demand regions of the United States: West North Central, West South Central, South Atlantic, and Middle Atlantic.

Projected Natural Gas Supply

Results suggest that natural gas supplies in North America will increase by a total of 18 percent between 2003 and 2013 as shown in **Table 4**. A majority of projected supply increases will come from the lower 48 states category.

Table 4: Projected Natural Gas Supplies for North America (in Tcf/yr)

Supply Sources	Projected 2003	Projected 2008	Projected 2013	Projected Increase 2003-2013	Percent Change 2003-2013
Lower 48 States	18.664	20.277	21.746	3.082	17%
Canada	7.046	7.230	7.402	0.356	5%
Other Sources	1.200	1.887	2.688	1.488	124%
TOTAL	**26.909**	**29.394**	**31.836**	**4.927**	**18%**

Source: California Energy Commission

In **Table 4**, 'Other Sources' are not supply basins in the lower 48 states or Canada and they include the quantity of fuel available from fuel switching, liquefied natural gas (LNG) receipt at existing U.S. import facilities, and Mexican imports. The fuel switching category is for those customers that are capable of switching between natural gas and other alternative sources of energy. As natural gas prices increase, competition occurs between natural gas and other energy supplies, such as fuel oil. The model substitutes the other supply sources to account for some of the natural gas these customers would have otherwise consumed.

The U.S. has four LNG import facilities, three along the Atlantic seaboard and one on the Gulf Coast. The basecase analysis assumed no new LNG facilities are built but existing facilities can expand as LNG imports become a cost-effective resource. The model also accounts for a small quantity of gas flows north from northeastern Mexico into the U.S. Gulf Coast.

Supply for United States

Projected Lower 48 production will climb to 21.8 Tcf/yr by 2013, up from 18.7 Tcf/yr in 2003, as shown in **Table 5**. Within the lower 48 States category, the Rocky Mountains region will have the greatest gains in production, a 63 percent increase between 2003 and 2013. Only three regions including Anadarko, California, and Permian will see a reduction in production.

Canada's production will contribute about 15 percent of the demand requirements of the lower 48 states. Imports from Canada will grow from 4.2 Tcf/yr in 2003 to 4.9 Tcf/yr in 2013. Other sources (e.g., LNG receipts, Mexican imports) will contribute an additional 1.5 Tcf/yr during the study period.

Table 5: Projected Natural Gas Supplies for the United States (in Tcf/yr)

Supply Sources	Projected 2003	Projected 2008	Projected 2013	Projected Increase 2003-2013	Percent Change 2003-2013
Lower 48 States					
Anadarko	2.203	2.077	1.899	(0.304)	-14%
Appalachia	1.136	1.285	1.601	0.466	41%
California	0.395	0.348	0.338	(0.057)	-14%
Gulf Coast	8.530	9.026	9.872	1.342	16%
North Central	0.561	0.665	0.778	0.218	39%
Northern Great Plains	0.310	0.353	0.389	0.079	25%
Permian	1.552	1.507	1.449	(0.103)	-7%
Rocky Mountains	2.141	3.048	3.486	1.345	63%
San Juan	1.836	1.969	2.014	0.179	10%
Total: Lower 48	18.664	20.278	21.827	3.163	17%
Canada	4.209	4.503	4.853	0.644	15%
Other Sources	1.200	1.887	2.688	1.488	124%
TOTAL	**24.072**	**26.668**	**29.368**	**5.296**	**22%**

Source: California Energy Commission

Table 5 also demonstrates that, while still representing a significant share of Lower 48 production, production in the southwest – from the Anadarko, Permian, and San Juan Basins – is projected to flatten out and start to decline during the next ten years. Combined production from these three basins will remain around 5.5 Tcf/yr throughout the forecast horizon. The southwest supply basins are old and past maturity, having been in production for nearly a century. Gulf Coast supply basins, however, will provide increased supplies by the end of the forecast horizon, growing from 8.5 Tcf/yr in 2003 to almost 10 Tcf/yr in 2013.

Supplies from the developing Rocky Mountains and Canadian production regions are expected to satisfy larger market shares of demand requirements. Supply originating in the

Rocky Mountains will reach almost 3.5 Tcf/yr in 2013, and Canadian imports will reach almost 5 Tcf/yr.

Supply for California

Table 6 indicates that the amount of supply provided by the Rocky Mountains will double during the forecast horizon. The Rocky Mountain region is a relatively new supply basin compared to other supply basins in the U.S. The prices in this region have been surprisingly low when the rest of the nation had very high natural gas prices. This is due to a lack of transportation pipeline capacity out of the Rocky Mountain Basin. To ensure market share, producers compete with each other for pipeline capacity. With recent expansion of the Kern River pipeline (in May 2003), the analysis demonstrates the importance of this supply source for California, and supplies coming from the Rocky Mountain region will be doubling over this time period.

Table 6: Projected Natural Gas Supplies for California (in Tcf/yr)

Supply Sources	Projected 2003	Projected 2008	Projected 2013	Projected Increase 2003-2013	Percent Change 2003-2013
Lower 48 States					
California	0.425	0.468	0.338	(0.087)	-20%
Rocky Mountains	0.327	0.619	0.725	0.398	122%
San Juan and Permian	1.036	1.002	1.008	(0.028)	-3%
Total: Lower 48 States	1.788	2.089	2.072	0.284	16%
Canada	0.634	0.679	0.700	0.066	10%
TOTAL	**2.422**	**2.767**	**2.772**	**0.350**	**14%**

Source: California Energy Commission

As shown in the Table, supplies from in-State production and from the southwest basins (i.e., San Juan and Permian Basins) are expected to remain relatively flat. Forecasted Canadian production will occupy a larger share of California's consumption, reaching 0.7 Tcf/yr by 2013. Incremental growth in gas demand will be met by supplies from the Rocky Mountain and Canadian basins.

Environmental Issues Associated with Natural Gas Exploration and Production

This section provides a discussion of the environmental issues related to the natural gas supply and the infrastructure used to deliver the gas to California. The major infrastructure needed for the supply includes:

- Exploration and drilling for natural gas,
- Pipeline development for gas transmission, and
- Liquefied natural gas (LNG) receipt and distribution facilities.

Environmental restrictions and regulations are dynamic and substantially influence the development of natural gas infrastructure. Regions of natural gas supplies could be made more available for exploration and production depending on changes in national and regional environmental policy.

Exploration in New Supply Basins

Long range planning of supply depends on quantifying future exploration. Access for exploration and drilling or development on federal lands is a subject of serious contention between the federal government, environmentalists, and natural gas development interests. The concerns focus on the potential for damage to these lands from the development of gas wells and production facilities.

The North American regions of greatest potential for natural gas exploration and increased drilling or development are the Gulf of Mexico, the Rocky Mountains, Canada, and Alaska.[i] Compared to regions in the U.S., Canadian supply regions are subject to different types of access restrictions and fewer federally mandated environmental restrictions.[ii]

Developing Offshore Supply Regions

In the Gulf of Mexico, the long-term outlook includes continued restrictions through federal and state legislation. Offshore exploration for gas in the shallow regions of the Gulf of Mexico (e.g. less than 1000 feet below sea level) has been curtailed in recent years because access to offshore natural gas resources is largely restricted by federal moratoria on leasing.[iii] It is anticipated that this restriction will continue after its expiration in 2012. Potential deepwater drilling sites are also subject to significant environmental regulatory restrictions that protect the ocean and offshore environment.

Developing Continental Supply Regions

Development of supply sources on the land has a demonstrated potential for being environmentally destructive and thus is highly scrutinized. Various federal, state, and local requirements must be satisfied before natural gas exploration, extraction, and infrastructure is implemented. Despite complex environmental requirements, a recent joint study completed by the U.S. Departments of Interior, Agriculture, and Energy indicates the situation is favorable for new gas exploration and extraction[iv]. The report states that there is a large amount of gas on public lands, and the access is either not significantly restricted or not restricted at all.

Natural Gas development in the Rocky Mountains is complicated by the process of extracting gas from the coal bed methane basins. Pumping out the highly saline water characteristic to these deposits leads to the environmental issues of water disposal and potential depletion of ground water aquifers. Recently the federal Bureau of Land Management issued a decision that would allow a large increase to coal bed methane drilling in the Powder River Basin of Wyoming and Montana. Before approving the development, the agency required a mitigation strategy for disposal of the saline wastewater associated with these gas deposits.

Development of New Pipelines

The environmental requirements for pipeline construction are similar to those specific to exploration and drilling. Transmission, distribution, and delivery systems for natural gas are also subject to access restrictions based on potential environmental impacts. Developing a pipeline is a lengthy and complex process even though pipeline construction affects a relatively narrow geographic area compared to exploration and drilling. Local community concerns regarding pipeline construction provides a challenge to expanding the gas transportation infrastructure. In general however, pipeline construction in the continental United States does not face widespread resistance from the general public.
Pipeline construction is most complicated in areas that are environmentally sensitive, such as the Alaskan wilderness. Development of a major gas transportation line from the North Slope of Alaska is currently being reviewed because of public concern over disturbance of the permafrost and protecting the pipe from damages that are a result of seasonal temperature fluctuations.[v]

Environmental concerns related to pipeline development do not substantially constrain supply. The gas transportation industry incorporates environmental mitigation steps associated with permitting in advance of project implementation. Compared to exploration and development, pipeline projects have considerable flexibility in that their alignments can be designed to simply avoid ecologically sensitive areas or other areas of potential concern.

Development of New LNG Facilities

In recent years, liquefied natural gas is an increasingly attractive means of augmenting supply infrastructure. This is especially the case in California because the state requires such large supplies. Although there are currently no licensed LNG facilities in California, there are a number of companies proposing LNG import facilities in or near California. These proposals are likely to meet significant public resistance because of the perception of LNG facilities as large, unsightly, and capable of catastrophic explosions.[vi] Public resistance stopped plans to develop an LNG terminal in the San Francisco Bay area of California within the past year.

The visual impacts of any LNG facility along the California coastline would be a public concern because much of the coast is prized for its natural beauty and recreational opportunities. Developers could consider locating LNG terminals in areas already occupied by industrial facilities. Possibilities exist for mitigating the visual impacts of these facilities, as evidenced in Japan where LNG tanks have been built underground.

A public outreach and education program is needed to inform the public as well as local and regional governmental agencies about the operations and safety of LNG facilities. Compared to the impacts of oil refineries and coal or nuclear power generation, fewer environmental impacts would likely be associated with LNG facilities.

Natural Gas Price Forecast

Introduction

This section provides a forecast of natural gas prices, including wellhead prices in North America, prices for electricity generators in the WECC region, and prices for customers of California's largest gas utilities. Increasing costs of finding natural gas to meet growing demand and bringing supplies to customers are driving natural gas prices to rise between 2003 and 2013.

Prices in the Basecase Forecast

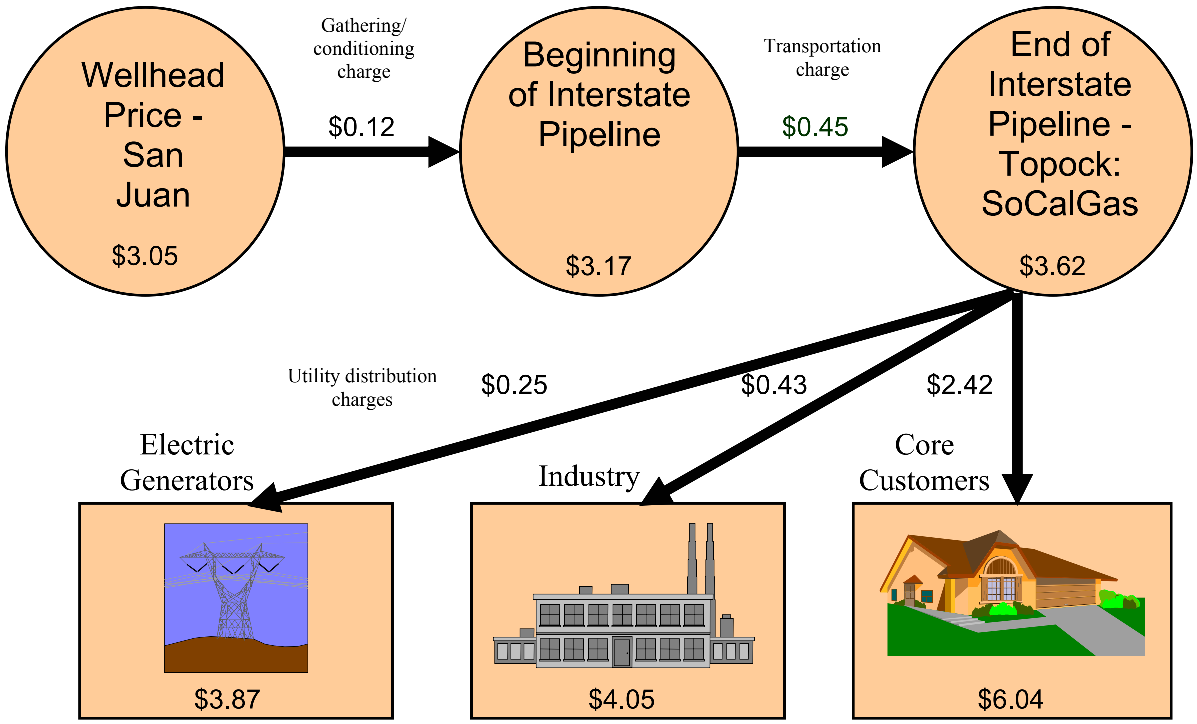
The natural gas prices shown in this chapter are long-term annual average prices. Showing long-term prices does not capture the seasonal price variability that occurs in the gas market. The basecase forecast represents the most likely estimate of how the gas market will behave over the forecast period based on demand, natural gas resources, transportation rates, and pipeline capacities. The basecase forecast assumes average weather conditions and availability of hydroelectricity in the WECC region. The forecast does not include the short-term consequences of temperature extremes, droughts, abundant hydroelectricity, or financial difficulties within the natural gas industry. All prices are adjusted for inflation and are expressed as year 2000 dollars.

Price Forecasting Methodology

Price Components

As illustrated in Figure 5, natural gas prices for the end-user are a result of the following factors: the wellhead price, the cost of gathering and conditioning the natural gas, the price of interstate pipeline transportation, and utility costs of distribution. Cost examples provided in **Figure 8** are based on the average of spot market transactions at the San Juan Basin to Topock, Arizona on October 4, 2002. The gathering and conditioning charge is based on various publications from the U.S. Department of Energy, Energy Information Administration (EIA). The transportation charge is the price of transporting natural gas from the San Juan Basin to the California border at Topock, Arizona. The remainder of the figure illustrates the computed charges for gas distribution within the SoCal Gas service area for each customer class. The end-use prices reveal that the wellhead price comprises about 80 percent of the price for industrial and electricity-generation customers and about 50 percent for core customers. Prices are reported in dollars per thousand cubic feet (Mcf).

Figure 5: Natural Gas Price Components ($ per Mcf)
Price Source: NGI, October 4, 2002



Sequence of Price Analysis

Natural gas price forecasting requires the following three sequential analyses:

- An analysis of likely supply and infrastructure, along with wellhead and border prices.
- An analysis of differing market conditions that influence resource availability.
- An analysis of sector-by-sector customer demands that influence delivery costs.

The price analysis begins with a review of long-term natural gas production, transportation, and demand throughout the North American continent. The geographic extent of this analysis includes the United States, Canada, and northern Mexico. Changes in price or supply can influence contiguous regions, which often creates a ripple effect across the continent. For each demand region, the North American Regional Gas (NARG) model identifies the likely sources of supply, wellhead prices, and border prices.

The second analysis considers the effects of uncertainty in the natural gas market. Staff presented two scenarios, a high-price and a low-price scenario, to determine price boundaries relative to the basecase assessment. Staff used an integrated price and supply outlook (IPSO) to estimate how different natural gas market conditions might influence both wellhead prices and supply availability. Unlike a sensitivity analysis that assesses changes in price due to variations in a single variable, this integrated outlook approach broadly examines the influence of a combination of market changes occurring at the same time. To develop the integrated outlook assumptions, staff modified the following five critical parameters: technological advances, resource availability, efficiency improvements affecting demand projections, oil prices, and oil use constraints.

The integrated outlooks predict plausible upper and lower price limits but not the actual volatility that is normally observed in the marketplace. Extreme price deviations are reachable but are not sustained because markets tend to correct themselves under volatile conditions when prices either rise or fall. After a brief price run-up or sag, the general, long-term trend returns due to buyer and supplier responses. The probability of price extremes occurring was not determined in this analysis.

The third analysis assesses the price for each utility customer class: residential, commercial, industrial, and power generation. Staff also produced a price projection for non-utility electricity generation customers receiving gas deliveries via the Kern and Mojave interstate pipelines. The assessment for utility customers was limited to California's three major gas utilities: Pacific Gas and Electric (PG&E), SoCal Gas, and San Diego Gas and Electric (SDG&E).

Staff matches supply and demand for each customer class then allocates gas transportation and distribution costs to these customer classes. Sources of gas-delivery cost information include firm and interruptible transportation agreements between the gas utilities and customers or between suppliers and non-utility customers, utility revenue projections, and other utility costs that have been approved for pass-through to customers by the California Public Utilities Commission (CPUC). This phase of the natural gas projections results in price projections for end-use customers.

Long-term versus Short-term Forecasts

Providing an annual average price projection does not provide insight into the volatility of the day-to-day or the seasonal market price. Four factors are not included in this analysis: weather, hydroelectricity availability, seasonal demand swings, and changes in economic parameters. This is a limitation in the long-term analysis described in this report. Staff has research underway to incorporate these factors into future assessments.

For example, during peak demand periods, a price run-up will occur if all the pipelines serving a region are full, with premium prices being charged to account for the transportation congestion. The increase in price will be moderated by the quantity of natural gas that is available from storage. Droughts could reduce the amount of available hydroelectricity, causing seasonal increases in natural gas demand. These effects can result in higher prices over fluctuating time frames. Quantifying these factors requires a comprehensive analysis of short-term market fundamentals.

Wellhead Prices in North America

Wellhead prices reflect the capital and production costs of natural gas and the willingness of buyers to pay for it. These prices motivate gas producers to explore, drill, develop, and produce the gas needed to satisfy consumer demand.

Reduced regulatory control at the wellhead in the United States and Canada caused natural gas supplies to increase, surpassing total natural gas demand from the mid-1980s to the late-1990s, which resulted in a reduction in natural gas prices. These low prices encouraged growth in natural gas demand. In response to this rising demand, wellhead prices began to increase in 1999.

The growing demand helped set the stage for wellhead price spikes by mid-2000. At that time, natural gas was preferentially used for electricity generation. Also, at this time there was little price incentive to store gas for the winter because the forward market was backwardated. When winter arrived in 2000, storage levels across the nation were below average levels. Cold months in November and December 2000 caused robust demand, which constrained the existing natural gas transportation infrastructure system and resulted in the inability of the natural gas companies to meet the demand. Low availability of hydroelectricity and price manipulation of the gas and electricity markets also contributed to dramatic price increases over the winter of 2000 - 2001. Gas prices dropped when demand weakened in mid-2001. For 2002, wellhead prices ranged between \$2.06 and \$3.71 per thousand cubic feet (Mcf), illustrating the price variability. **Figure 6** shows these historical trends in monthly wellhead prices.

Figure 7 illustrates the historical path of annual average wellhead prices in the Lower 48 States with the basecase price assessment provided after 2002. As shown in **Figure 7**, between 2003 and 2013, the following ranges are plausible deviations in wellhead prices in the Lower 48 States:

- Above the forecast, the variations increase from \$1.19 to \$1.41 per Mcf.
- Below the forecast, the variations increase from \$0.33 (Year 2003) to \$0.54 (Year 2013) per Mcf.

Figure 6: Historical Wellhead Prices in the Lower 48 States –Monthly Averages
Source: EIA

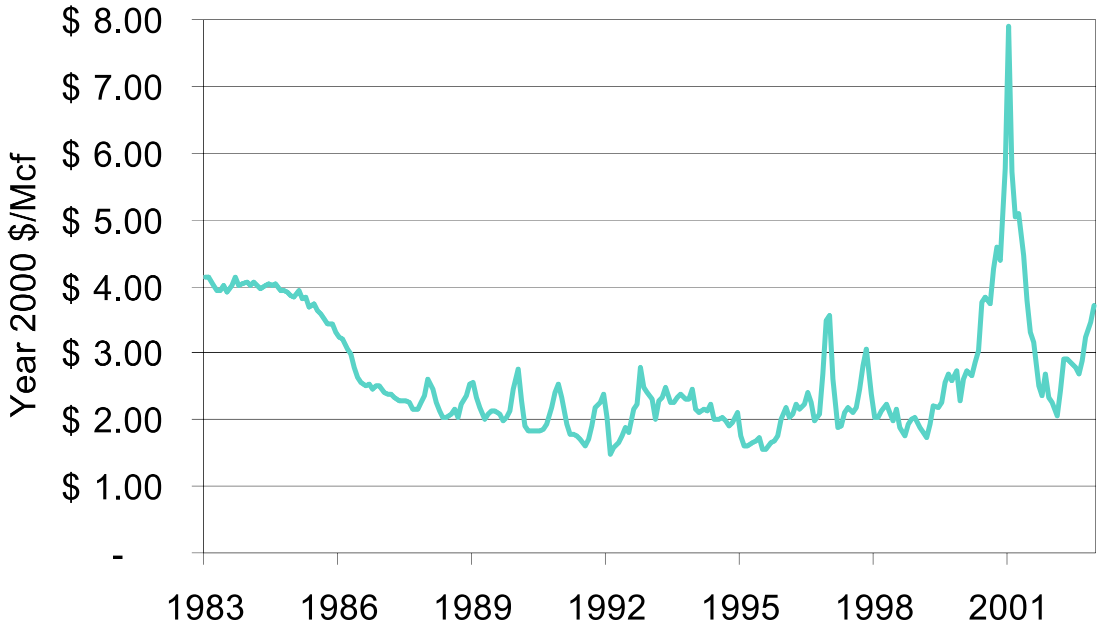


Figure 7: Historical and Projected Wellhead Prices in the Lower 48 States with High and Low Boundaries – Annual Averages
Source: EIA (Historical Data) and the California Energy Commission (Forecast)

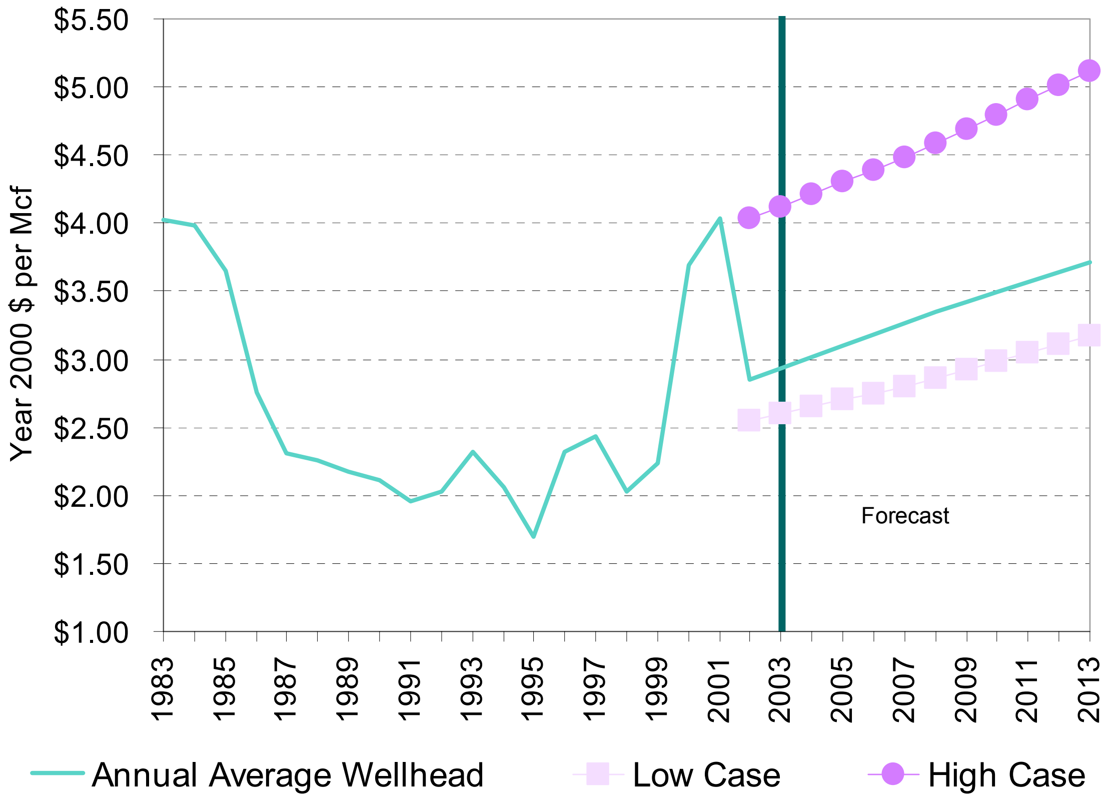


Table 7 gives the projected prices, in year 2000 dollars per Mcf, for major gas-producing regions throughout North America.

The differences of wellhead prices between regions stem from dissimilar regional demand growth, varying resource costs, differences in access to production basins, and available pipeline capacity. Wellhead prices in the following regions are especially of interest to California because they are expected to provide the majority of the supply:

- California
- Permian
- Rocky Mountains
- San Juan Basin
- Alberta

Wellhead prices for Canadian gas supplies will likely be less than those in the Lower 48 States, but prices from both sources are expected to increase by more than two percent annually. The 2013 weighted-average price for Canadian wellhead gas is projected to be $3.12 per Mcf, compared to $2.49 in 2003. By 2013, the lowest-cost production regions in the Lower 48 States will most likely be the Rocky Mountains, the San Juan Basin in the Four Corners region, and the Northern Great Plains Basin in Montana. In 2013, all three production regions will have wellhead prices below the weighted-average price for the Lower 48 States of $3.71 per Mcf.

Table 7: Projected Wellhead Prices – Annual Averages ($ per Mcf)

Producing Region	2003	Projected 2008	Projected 2013
Lower 48 States			
Anadarko	3.14	3.57	4.04
Appalachia	3.55	3.91	4.19
California	3.16	3.56	3.89
Gulf Coast	3.04	3.42	3.82
North Central	3.22	3.54	3.83
Northern Great Plains	2.57	2.78	2.95
Permian	3.04	3.44	3.85
Rocky Mountains	2.73	2.96	3.20
San Juan	2.76	3.12	3.46
Weighted Average: Lower 48	**3.02**	**3.34**	**3.71**
Canada			
British Columbia	2.65	3.05	3.41
Alberta	2.41	2.73	3.02
Saskatchewan	3.22	3.76	4.14
Eastern Canada	3.72	3.64	3.88
Weighted Average: Canada	**2.49**	**2.82**	**3.12**

Source: California Energy Commission

The rank order of the three lowest-priced production regions in the Lower 48 States are (starting with the least expensive): Northern Great Plains, Rocky Mountains, and San Juan Basin, and does not change between 2003 and 2013. The Rocky Mountain and San Juan Basins will continue to have relatively low wellhead prices. The Permian basin becomes relatively more expensive by 2013 moving from the middle of the pack to the fourth most expensive. The Northern Great Plains Basin and the Appalachia Basin are, respectively, the least and most expensive production regions throughout the forecast, but are essentially inaccessible for California's needs.

The assessment of wellhead gas prices in the lower 48 and Canada, indicated in Table 7, includes the following:

- Prices for gas produced in the Lower 48 States are expected to grow 2.1 percent per year, climbing from $3.02 in 2003 to $3.71 per Mcf in 2013.
- Canadian wellhead prices will likely increase 2.2 percent per year, from $2.49 in 2003 to $3.12 per Mcf in 2013.

As explained in the supply and demand chapters, an increase in projected wellhead prices is largely driven by growth in demand, especially by customers who can not substitute an alternative fuel for natural gas.

Gas Prices for Electricity Generators in the WECC Region

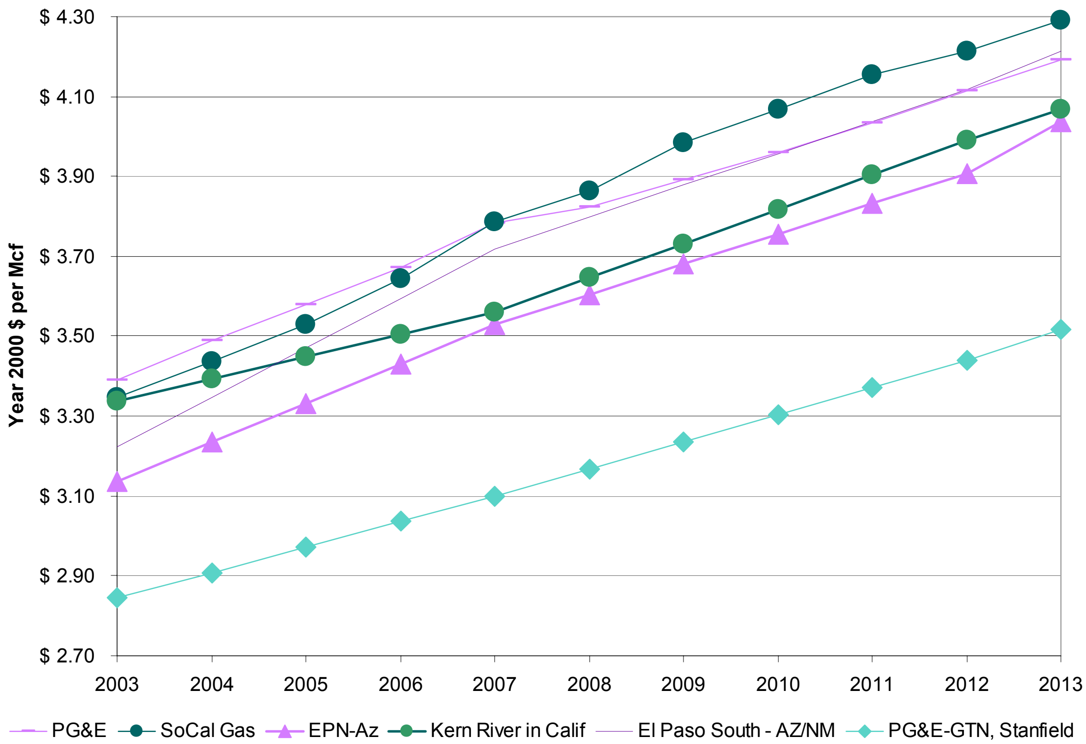
Low wellhead prices and easy access to affordably priced natural gas along interstate pipelines are attractive to gas-fired electricity power generators. **Figure 8** shows the price projections for electricity generators located within the WECC region.[vii] Buying gas directly from interstate pipelines allows gas customers to avoid gas-utility distribution costs, associated taxes, and surcharges. Other costs or constraints, however, may be incurred by locating a power plant near an interstate pipeline. Saving on gas costs is particularly important to merchant generators who compete for market share based on their electricity prices. Other factors that power plant developers consider include proximity to electricity transmission systems and costs to connect to it, including congestion costs.

Electricity generators who receive large gas shipments from in-state utility-owned gas lines are classified as noncore customers in the PG&E, SoCal Gas, or SDG&E gas utility systems. They purchase gas supplies from third parties. It is projected that the electricity generators located in California will probably pay higher natural gas prices, approximately two percent above inflation annually. As noncore customers in the utility systems, these electricity generators will be paying higher prices for gas compared to electricity generators taking gas directly from interstate pipelines. Electricity generators located near California demand centers, however, may be offsetting these higher gas prices by reducing other expenses, such as transmission line losses and costs.

Electricity generators receiving gas from PG&E will pay about the same price as electricity generators in southern California. Commodity prices will be lower in PG&E's service area, but these are partially offset by higher transportation costs that eventually become cheaper over time. PG&E is likely to attain a slight price advantage over southern California after 2006.

Figure 8: Projected Natural Gas Prices for Electricity Generators within the WECC Region

Source: California Energy Commission



The lowest-cost for natural gas is, and will continue to be, Canadian gas via the PG&E Gas Transmission Northwest (GTN) interstate pipeline at the Washington-Oregon border in Stanfield, Oregon.

In Arizona, electricity generators will probably see a slight price advantage through 2013 for gas delivered using the northern El Paso pipeline corridor – a corridor that includes El Paso, Transwestern, and Southern Trails pipeline systems – rather than the southern El Paso corridor. The major advantage comes from easier access to low-priced San Juan Basin gas compared to gas from the Permian and Anadarko Basins. Since much of the new, electricity generation capacity appears to prefer locations along the northern El Paso pipeline corridor, the necessary pipeline infrastructure improvements would add costs to these prices.

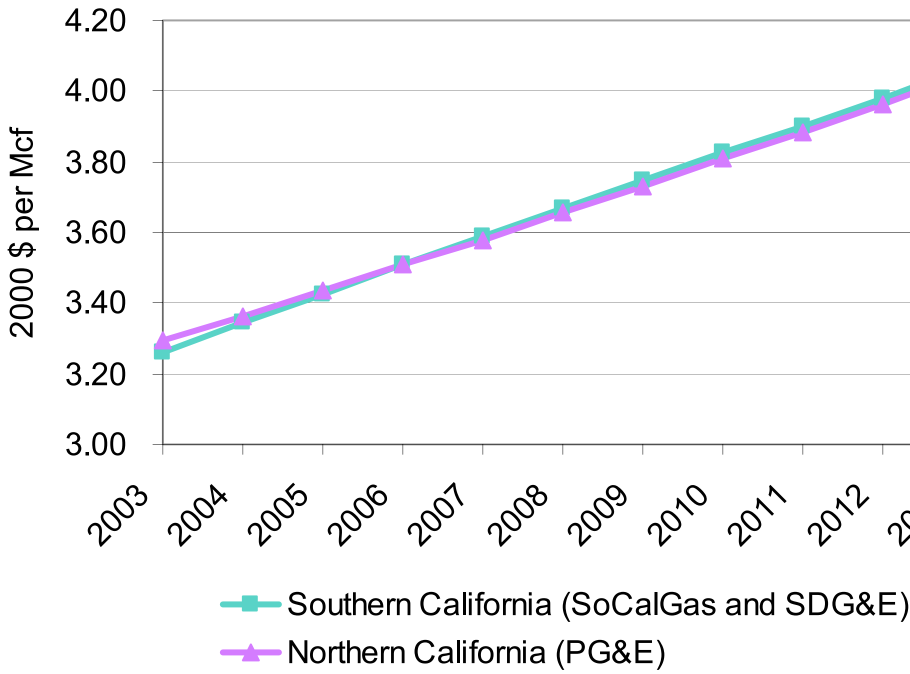
California Border Prices

This section provides the forecast of California border prices for both Northern California (PG&E service area) and Southern California (SoCal Gas and SDG&E). These prices represent what utility customers mostly likely will pay for gas to be delivered to the utility service system, but do not include other costs, such as local distribution and regulatory charges.

Generally, both Northern and Southern California prices are very close to each other. In 2003, the Southern California price is about three cents per Mcf lower than the Northern California price. Northern California prices will likely grow at a 2.1 percent annual rate, whereas Southern California prices will increase at a 2.3 percent rate. Northern California prices grow at a slower rate because of the access to lower priced Canadian supply. **Figure 9** shows that the average price for gas at the California borders for California's major gas utilities are expected to increase to slightly over $4.00 per Mcf by 2013.

Figure 9: Projected California Border Prices – Annual Averages

Source: California Energy Commission



Gas Prices for California Gas Utility Customers

Commission staff forecasted prices for each major gas utility's core and noncore customers using the forecasted California border prices.

Figure 10 shows volume-weighted annual-average prices for all customers in the PG&E, SoCal Gas, and SDG&E service areas, expressed in year 2000 dollars per Mcf. These system-average prices are expected to settle between $4 and $6 per Mcf. During the next ten years, gas prices are likely to fluctuate above or below this basecase assessment due to short-term shifts in supply availability, seasonal and demand fluctuations, regulatory changes, and other factors affecting short-term market trends.

Figure 10: Historical and Projected Utility End-Use Prices in California – Annual Averages

Source: California Energy Commission

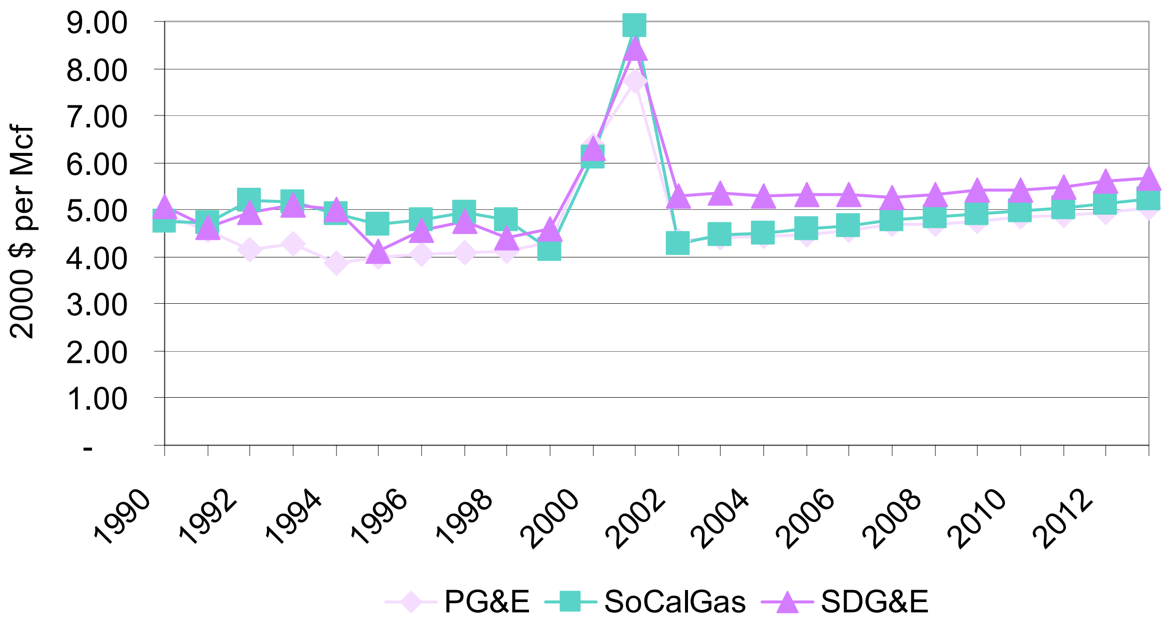


Figure 10 also shows the price spike of 2000-2001, when prices reached about $9 per Mcf, on an annual average basis, in some instances. The spike occurred because demand was strong, supply deliverability was tight, and price manipulation occurred.

When prices increased, producers increased drilling and gas-pipeline owners expanded pipeline capacity and storage facilities. At the same time, gas consumers conserved energy to decrease their demand and utility bills. A slowdown of the national and California economies also contributed to lower demand. As a consequence, prices returned to the $4 to $6 per Mcf range after 2001. The long-term assessment calls for gas prices to remain between $4 and $6 per Mcf.

Natural Gas Infrastructure

Natural gas demand drives the need for planning new natural gas infrastructure. The geographical location of the natural gas demand determines how much pipeline capacity is needed. This section explains the pipeline network that serves California and its capacity to serve the anticipated demand. The analysis primarily focuses on interstate pipelines that bring natural gas from various producing basins in the United States and Canada. Nearly 85 percent of the natural gas supplies for California arrive through the interstate pipelines.

Interstate Pipelines Serving California

Interstate pipelines transport natural gas from the southwestern United States, Rocky Mountains, and Canada to California. Figure 11 shows the locations for the natural gas supply areas and major interstate and backbone pipelines serving the western states. The map also shows that California is at the end of the interstate pipeline systems, and that natural gas travels large distances before reaching California.

Southwest Corridor

California receives its southwest supply principally from the San Juan Basin in New Mexico and Colorado and the Permian Basin in west Texas. The Anadarko Basin in the north Texas and Oklahoma panhandle area also supplies limited quantities. Three companies bring southwest supply to California: El Paso Natural Gas Company, Transwestern Pipeline Company (TW), and Questar Southern Trails Pipeline Company (ST). Each of these companies operates a pipeline that crosses Arizona north of Phoenix and terminates in Topock, Arizona, near Needles, California. The combined capacity of these pipelines in the northern corridor is approximately 3,600 million cubic feet per day (MMcfd). El Paso also operates a southern pipeline that arrives in Ehrenberg, Arizona near Blythe, California.

Gas from the San Juan Basin is transported to California on the northern El Paso, Transwestern, and Southern Trails systems. Historically, the northern El Paso and Transwestern pipelines also brought gas from the Permian and Anadarko Basins to California, although normally, San Juan Basin gas now moves east on the El Paso and Transwestern systems to Texas. Supply into these pipelines may originate from the San Juan Basin or from the Rocky Mountain Basin via either the Northwest (Williams Gas) or the TransColorado pipelines (Kinder Morgan).

Gas from the Permian Basin arrives in California in the southern El Paso pipeline. The Anadarko Basin does not normally supply gas through the El Paso system to California because the northern part of the El Paso system is used to carry San Juan Basin gas to the many eastward interstate pipelines with origins in the Anadarko. The El Paso Plains All American pipeline built to transport crude oil from California to Texas was recently converted to carry natural gas from the Permian Basin to California. This pipeline parallels the southern portion of El Paso's system that terminates at Ehrenberg, Arizona. The combined capacity of the southern corridor with the All American conversion is approximately 1,500 MMcfd.

Kern River Corridor

Gas from the Rocky Mountain Basin arrives in California mainly through the Kern River Gas Transmission Company pipeline system. The Kern River pipeline terminates inside California near Daggett, unlike the southwestern pipelines that terminate at the California border. The 700 MMcfd capacity of the original Kern River pipeline built in 1992 was expanded by 142 MMcfd after the 2000 energy crisis, and again by 906 MMcfd in May 2003. Total capacity of this corridor is currently approximately 1,750 MMcfd. Besides the Kern River pipeline, natural gas from the Rocky Mountain Basin may also be shipped via the San Juan Basin by the Northwest and TransColorado pipelines for ultimate delivery to California by the northern El Paso, Transwestern, and Southern Trails pipelines.

Pacific Gas and Electric (PG&E) Gas Transmission Northwest Corridor

The PG&E GTN system carries natural gas produced in Alberta, Canada from Kingsgate, British Columbia for delivery to California at Malin, Oregon. PG&E GTN may also receive gas from British Columbia, Canada and the Rocky Mountain Basin at Stanfield, Oregon via the Northwest Pipeline.

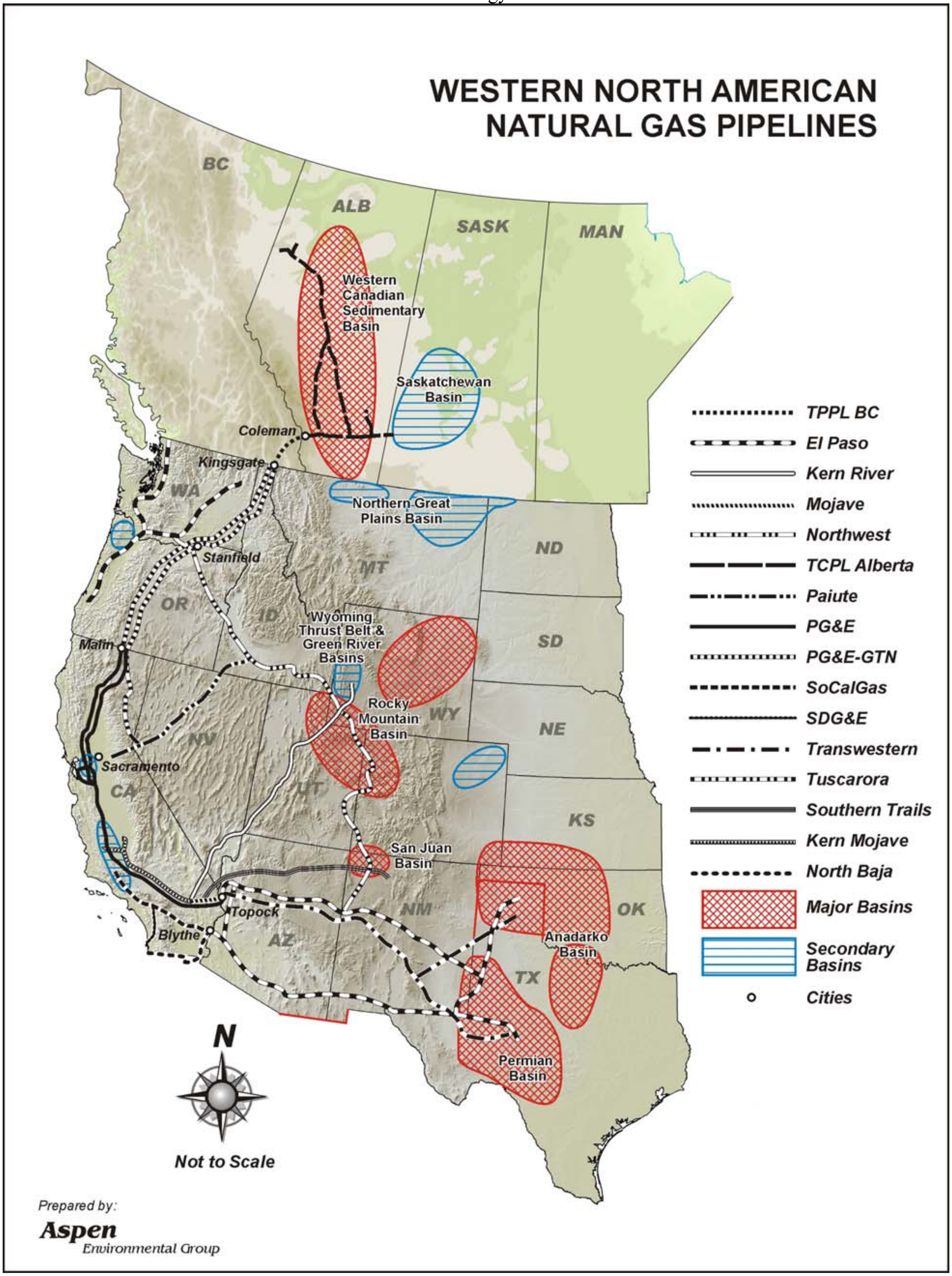
California-Mexico Corridor

PG&E National Energy Group and Sempra Energy International completed a new 500 MMcfd pipeline in December 2002, connecting Ehrenberg, Arizona and Blythe, California to Rosarito, Baja California through Mexico. The North Baja pipeline receives natural gas from the southern El Paso system at Ehrenberg and transports it to power plants and potential industrial demand along the border and in Rosarito, Baja California.

Mojave Pipeline

The Mojave Pipeline Company, owned by El Paso Corporation, constructed a pipeline in 1993. The Kern River and the Mojave pipelines combine into a single pipeline inside California near Daggett. The Mojave pipeline, with a capacity of 400 MMcfd, transports natural gas from Topock, Arizona to power generators and enhanced oil producers in Kern County.

Figure 11: Western North American Natural Gas Pipeline
Source: California Energy Commission



Infrastructure Modeling Methodology

The supply needed by California, especially driven by new gas-fired power plants, may be jeopardized by increased demand in Arizona, Nevada, Oregon, Washington, or Mexico. Customers in these areas share the interstate infrastructure shown in **Figure 11**. Existing capacity and recent expansions to pipelines in the Kern River and PG&E GTN corridors seem to be adequate to meet the needs of customers in these regions. However, supplies may be constrained by the infrastructure of the southwest corridor. This analysis indicates a large amount of pipeline capacity will soon be needed in the southwest. **Table 8** is a summary of the current capacity of each interstate corridor.

The Federal Energy Regulatory Commission (FERC) regulates all interstate pipelines. It does not, however, set any guidelines or requirements for reliability of service by interstate pipelines, subsequent to the implementation of open access orders. There is no rule in FERC regulations that mandate a specific amount of operating and excess capacity on interstate pipelines to meet the natural gas demand in California. The FERC relies on market forces and incentives to ensure sufficient interstate pipeline capacity. There is uncertainty in whether market incentives will be able to ensure enough interstate pipeline capacity to serve the needs of California during droughts and adverse temperature conditions. In this analysis, Energy Commission staff assesses the impact of increased demand due to adverse weather conditions on the need for additional interstate pipeline capacity. The present analysis only reviews the impacts under annual average conditions. An analysis of the market under short-term conditions, to capture seasonal variations, will be completed after 2003.

Table 8: Major Interstate Pipelines and Pipeline Capacity Serving California

Pipeline Corridor	Major Pipelines	Location	2003 Capacity (MMcfd)
Southwest Corridor	Southern El Paso (with All American Interstate)	Blythe, CA	1,440
	Northern El Paso Transwestern (TW) Questar Southern Trails (ST)	Topock, Arizona	2,970 (combined)
	El Paso Havasu Crossover	Western Arizona	720
Kern River Corridor	Kern River	Daggett, CA	1,750
PG&E-Gas Transmission North Corridor	PG&E-GTN	Malin, OR	2,150
	PG&E-GTN	Kingsgate, WA	2,860
California Total*			8,310

* Total does not include the capacity on Havasu Crossover, and the PG&E-GTN line to Kingsgate pipelines.
Source: California Energy Commission

Natural Gas Infrastructure Assessment

El Paso Corridor

The El Paso Natural Gas Company provides the major natural gas transmission infrastructure in the southwest corridor. In March 2001, El Paso solicited interest from potential natural gas shippers to test the need for new pipeline capacity for its customers in California and other southwest states. Shippers indicated, in their responses to the solicitation, an interest to ship as much as 9,700 MMcfd. However, the shipper interest for firm transportation commitment has been lacking along the northern portion of El Paso's system, which includes the competing Transwestern and Southern Trails systems. These systems provide a combined capacity of 3,600 MMcfd. Since 2001, El Paso has not announced any plans for expanding the northern portion of its system.

Recent expansions in the southwest corridor as of May 2003 include:

- **All American Pipeline**. The El Paso Plains All American crude oil pipeline, along the southern portion of the El Paso system, was recently converted to carry 230 MMcfd of natural gas from the Permian Basin to Ehrenberg, Arizona near Blythe. El Paso plans to expand this pipeline by 320 MMcfd over the next few years.
- **TW Red Rock**. Transwestern completed its Red Rock pipeline expansion in 2002. This provides an additional 120 MMcfd to California at Needles, California.
- **Southern Trails Pipeline**. Questar converted the oil pipeline from Four Corners to California border, bringing 80 MMcfd of natural gas supplies from the San Juan basin to California at Needles. This pipeline was completed in June 2002.

Figure 12 shows the 2003 capacity of major pipelines in the southwest corridor and demonstrates how much additional capacity will be needed to deliver natural gas to California and customers in western Arizona and Mexico. **Figure 12** includes the recent projects listed above.

Upstream Pipeline Needs in the Southwest Corridor

According to the Energy Commission's model analysis, California gas supply from the southwest is projected to remain comparatively stable for the next ten years. (See Table 6: Projected Natural Gas Supplies for California.) All the pipeline growth that is reflected in Figure 12 is not to meet California future gas requirements but to meet East of California needs.

Natural gas pipeline flows in Arizona / New Mexico region along El Paso's northern system are anticipated to grow substantially over the next ten years. This is because of the anticipated increase in power plant construction, south of Phoenix, Arizona and along the North Baja pipeline, a new 500 MMcfd pipeline in Mexico.

Energy Commission modeling analysis indicates supply for the growing demand in western Arizona and Mexico will flow west from the San Juan Basin through the northern El Paso, Transwestern, and Southern Trails systems. Just east of Topock, Arizona, the gas will flow south over the El Paso Havasu Crossover. From the Havasu Crossover, gas can flow either east on the southern El Paso pipeline to the new power plants or to California or to Mexico from Blythe on the new North Baja pipeline.

Price difference between the San Juan and Permian supply regions result in underutilization of the southern portion of the El Paso system. The new demand growth for power generation and industrial use located in Arizona, New Mexico and in Baja California (along the North Baja Pipeline) prefer the cheaper San Juan and Rocky Mountain Basin supplies. (See Table 7: Projected Wellhead Prices for Lower 48 and Canadian Producing Regions for comparisons of projected basin wellhead prices.) These generators prefer to pay for new or incremental pipeline capacity that accesses cheaper supply sources in the San Juan and Rocky Mountain Basins rather than use the more expensive gas from the mature Permian Basin.

Under the basecase assumptions, the El Paso Havasu Crossover and the northern El Paso, Transwestern, or Southern Trails systems are expanded to meet the increased demand in the southwest and could be needed within the next five to ten years. Basecase results show that the present Havasu Crossover capacity will be exceeded by nearly 250 percent (1,100 MMcfd) over the next ten years. The combined carrying capacities of the northern El Paso, Transwestern, and Southern Trails systems must also increase by 600 MMcfd by 2008 and by more than 700 MMcfd by 2013. Additionally the San Juan Crossover (which includes the combined El Paso North and Transwestern capacity) would need to expand the west to east flowing ability by about 350 MMcfd.

The following further discusses these expansions as well as other options that are available to meet the growing southwest pipeline needs. Additionally, contractual arrangements that could put southwest supply to California in jeopardy are also discussed.

El Paso North/Transwestern and Southern Trails Corridor Options. The modeling analysis indicates that about 700 to 800 MMcfd in new pipeline capacity will be needed in the next ten years along this corridor. Either one or all the existing pipelines in this corridor could expand their pipelines to meet the apparent growing capacity needs. To date only Transwestern, with its Red Rock expansion, has done so. This expansion has been included in the modeling analysis and is not part of the new requirements.

Kinder Morgan's recently proposed **Silver Canyon Pipeline** project could potentially satisfy most of the pipeline requirements along this corridor. Construction of the new 700 MMcfd Silver Canyon pipeline would originate near the San Juan Basin providing the possibility of shipping both San Juan and Rocky Mountain natural westward. Feeding the new project would be Kinder Morgan's proposed expansion and extension of its TransColorado pipeline with access to the Rocky Mountain supply region.

As of January 2003, Silver Canyon's proposed path would be west from near the San Juan Basin. It would turn south near the Phoenix, Arizona area, paralleling the Havasu Crossover to provide service to the growing power plant demand in western Arizona and putting it in a position to deliver natural gas to both the North Baja Pipeline and to SoCal Gas at Blythe.

El Paso Havasu Crossover Options. There are several options to meeting the Havasu Crossover pipeline 1,100 MMcfd expansion needs to flow gas from northern Arizona to south Arizona. The most obvious would be for El Paso to expand its existing pipeline to meet the growing need. While El Paso has not proposed to do this recently it has done so in the past. Other potential projects have been offered recently.

- **Desert Crossing.** Construction of the new 800 MMcfd Desert Crossing Pipeline (Proposed by the Allegheny Energy Supply Company, SRP, and Sempra Energy Resources). This project may extend from the Kern River pipeline in southern Nevada to the southern El Paso pipeline system in western Arizona. It would also include access to new storage facilities. As proposed the pipeline would provide the flexibility to flow regionally to both to the north and to the south with interconnections with El Paso, Southern Trails, and Transwestern pipeline systems.
- **Four Corners.** Conversion of the former Four Corners crude oil pipeline (Questar Southern Trails) between Topock, Arizona, and a point on SoCal Gas's southern system could provide 120 MMcfd into the Southern California market. Questar Southern Trails has only presented this system to provide westward flowing capacity. There would be the possibility of displacement of supply from the SoCal Gas system at Blythe/Ehrenberg to El Paso South or North Baja pipelines.
- **Silver Canyon.** A major portion of Silver Canyon would parallel the Havasu Crossover. As indicated earlier Silver Canyon would offer 700 MMcfd in new pipeline capacity. Energy Commission understands this portion of the project flow would be in a southern direction.

All American Lateral Option. The portion of the former All American crude oil pipeline within California is planned for conversion to transport natural gas between Ehrenberg, AZ at the CA border and Daggett, CA. The operational features will provide for natural gas to flow in either direction providing significant flexibility to meet regional changes in demand. The conversion project proposed by El Paso may be completed by the July 2004. This valuable "lateral" connection between Ehrenberg and Daggett links the southwest corridor with the Kern River and Mojave pipelines.

This pipeline project is included in the basecase analysis as it is anticipated that it will be completed by the July 2004. With a capacity of 500 MMcfd, the Energy Commission's model indicates it would be flowing at between 300 and 400 MMcfd by 2013, transporting natural gas from the Rocky Mountain basin to Ehrenberg, where the gas can flow into Southern California or onto the North Baja Pipeline to satisfy Mexican markets.

Compared to the December 2002 Staff Paper, inclusion of the All American "lateral" between Blythe and Daggett has several effects. First it reduces the need for additional Havasu Crossover capacity. Second, it also reduces the westward flow of natural gas from the San Juan Basin. However, adding the capacity of the All American "lateral" would still not provide sufficient supply to meet the full demand for gas from the San Juan and Rocky Mountain Basins.

San Juan Crossover Option. The San Juan Crossover corridor is the portion of the El Paso and Transwestern pipeline systems that lie between the San Juan and Permian Basins and has bi-directional flow capabilities. To meet the anticipated growth in demand in the area south of Phoenix, Arizona natural gas can be transported from the San Juan Basin across New Mexico to the east on either the El Paso or Transwestern pipelines in the San Juan Crossover corridor to the Permian Basin. Then the gas can flow to the west on the El Paso's southern pipelines. This option would allow El Paso to take advantage of the slack capacity on the southern El Paso pipeline system (including the recent conversion of the All American Pipeline). This would however require an expansion of the San Juan Crossover portion of the pipeline over and above the 350 MMcfd that basecase modeling indicates will be needed in the next ten years.

Dispute Regarding Upstream Demand in Southwest Corridor. California natural gas utilities and the CPUC or in a dispute with upstream customers on the El Paso Natural Gas Company system regarding the firm rights to pipeline capacity. These upstream customers in Arizona and New Mexico claim full rights to utilize as much of the pipeline capacity as they need. This would constrain California's use of the El Paso system, thereby degrading the supply reliability for California customers. With FERC's recently announced elimination of the Full Requirement status on the El Paso pipeline's large customers in Arizona, a long-standing issue has been resolved. Thus customers in all three states (CA, AR and NM) can now reassess their needs for pipeline capacities to meet their supply needs. It is anticipated that interest in new projects such as the Silver canyon, and the Coronado pipeline.

LNG Development Impacts on the Southwest Corridor Options. LNG received and regasified in Baja California, Mexico could flow to Blythe on the North Baja pipeline. The limit on the quantity of gasified LNG that could flow east would be the current 500 MMcfd capacity of the North Baja pipeline, with possibly another 500 MMcfd that could be added by adding compression facilities on the North Baja pipeline. From Ehrenberg, the gas can be transported on the southern El Paso pipeline to western Arizona or to Southern California markets. This would preserve up to 500 MMcfd of gas from the southwest corridor that would have otherwise been supplied to Mexico for use instead in Arizona and California.

Any LNG projects that would be located in California would reduce the need for natural gas supply from the southwest and other sources as the Rocky Mountains and Canada. The pipeline capacity that otherwise would have been used to meet California needs would be then available for meeting demand upstream of California. Staff analysis on the impacts of LNG on the California natural gas market is provided in the chapter on scenarios.

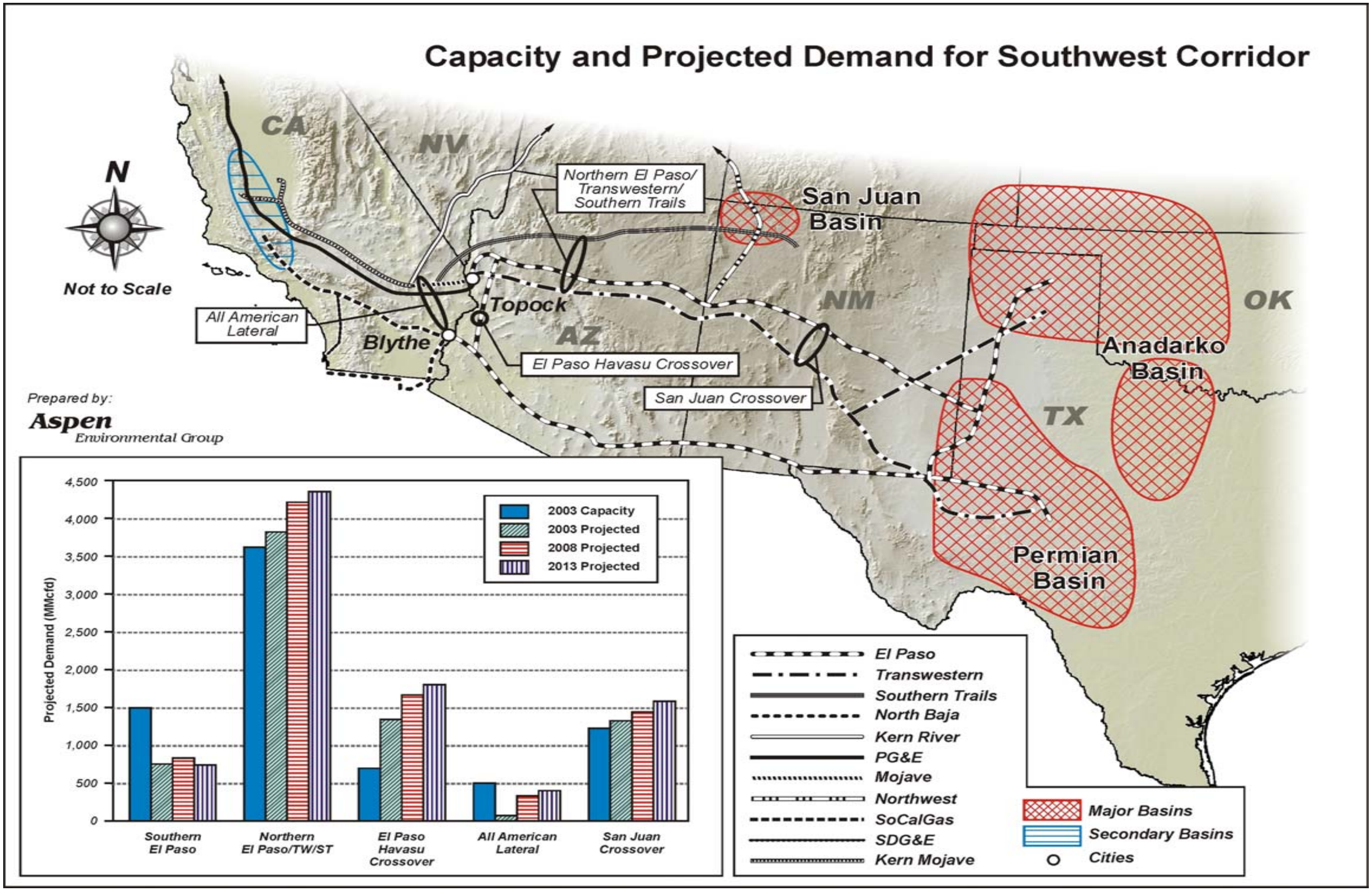


Figure 12: Southwest Corridor Interstate Pipeline Capacity Compared to Forecasted Flowing Supply

Source: California Energy Commission

Dispute Regarding Upstream Demand in Southwest Corridor

The State of California is in a dispute with customers on the El Paso Natural Gas Company system in Arizona and New Mexico regarding the firm rights to use capacity of the pipeline. These upstream customers claim full rights to utilize all capacity on the pipeline, which would constrain California's use of the El Paso system, thereby degrading the supply reliability for California customers. The FERC agreed to settle the dispute between the parties, and proceedings are ongoing. Until the FERC settles this matter, customers will be unable to determine how much capacity will be available for reliable service. Thus, customers are reluctant to commit to paying for or subscribing to new capacity and will be reluctant to support any new capacity that is needed.

Kern River Corridor

Natural gas from the Rocky Mountain Basin comes to California mainly through the Kern River Gas Transmission Company pipeline system. The pipeline provides service to not only California but also to Utah and Nevada. New gas-fired power plants have been built along the pipeline corridor, and more are under construction or being planned. The new projects place increasing demand on its initial 700 MMcfd carrying capacity. To respond to the increased demand, Kern River increased its natural gas shipping ability. As a result of an emergency order, the capacity was expanded by 146 MMcfd with additional compression in June 2002. On May 1, 2003, the last of its current expansion projects was completed bringing its total capacity to 1,750 MMcfd.

Figure 13 illustrates that the current Kern River corridor capacity will be adequate to meet short term needs but will not be enough to meet all the anticipated demand. Another 500 MMcfd may be needed by 2013. This analysis indicates that Kern River would provide up to 400 MMcfd, transporting the gas along the All American lateral from Daggett to Ehrenberg to meet demand in southern California and Mexico.

PG&E Gas Transmission Northwest Corridor

The original PG&E Gas Transmission Northwest pipeline (PG&E GTN) had a capacity of about 1,070 MMcfd. This was expanded by an additional 900 MMcfd in 1992 with new pipeline looping and added compression. Growing demand in the western states led to an additional increase of 170 MMcfd in 2002. This brings the total capacity to transport Canadian gas to the California, Pacific Northwest, and Nevada markets to about 2,150 MMcfd. **Figure 13** shows projected gas flows on the PG&E GTN pipeline corridor between Canada and the California border. It is anticipated there will be little need for expanding the PG&E GTN pipeline system until the very end of the ten-year study period. This is principally because there is limited need to add new gas-fired electric generation in the region. Additionally, demand growth on the Tuscarora Pipeline, which receives natural gas at Malin, Oregon for delivery to Reno, Nevada, will not be sufficient to warrant additional pipeline expansion.

This staff analysis indicates that the 2002 expansion plan completed by PG&E GTN will be sufficient to meet its customer's needs for the next ten years. With PG&E GTN running nearly full by 2013, new capacity would be needed at that time.

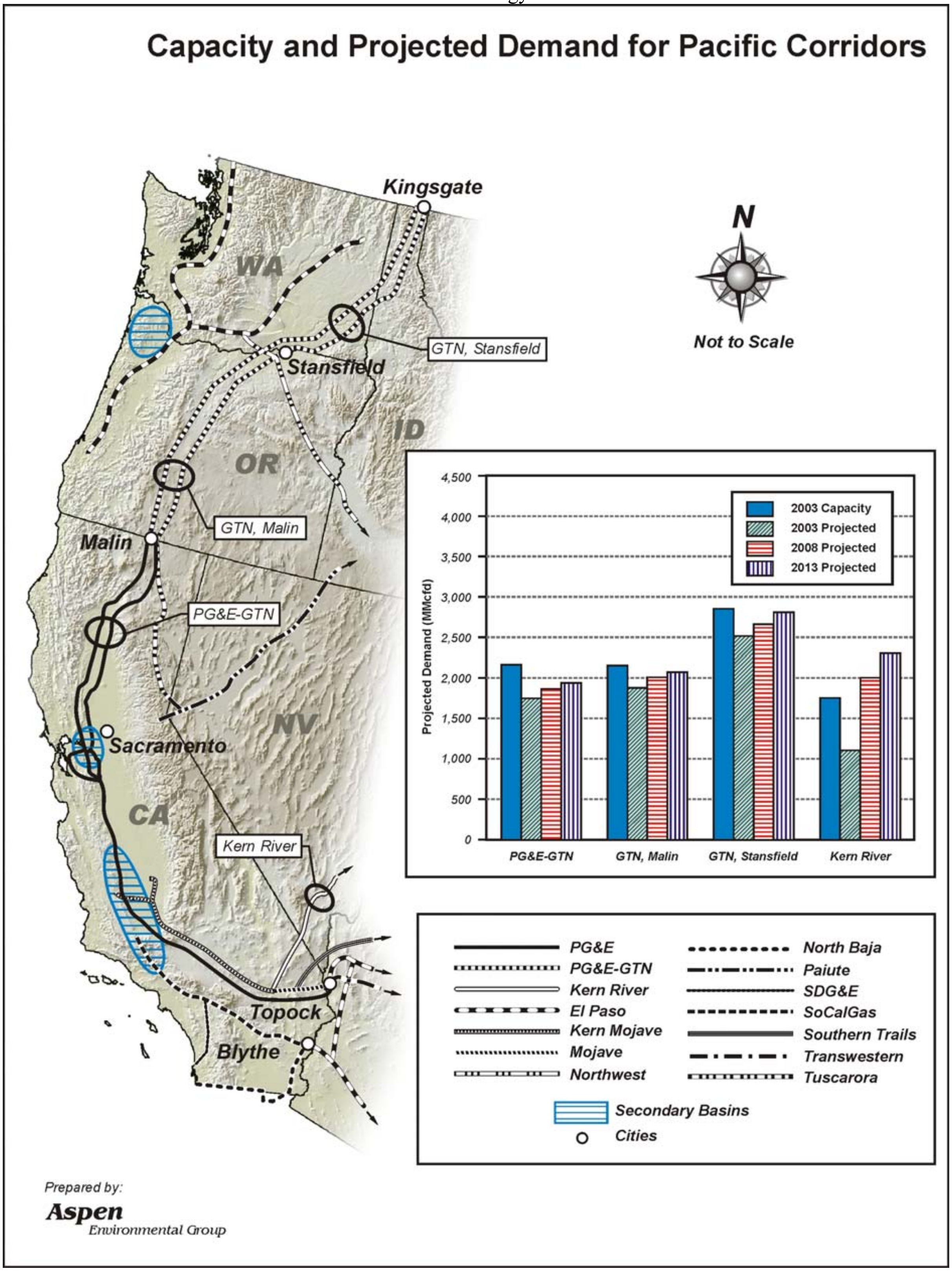
Infrastructure within California

Both PG&E and SoCal Gas have increased their capacity to receive and store natural gas in their respective service areas. PG&E added 170 MMcfd in 2002, and SoCal Gas recently completed the addition of 375 MMcfd. SoCal Gas has also expanded its total storage capacity at the Aliso Canyon and La Goleta storage facilities. Two private storage operators in northern California have improved supply reliability in this area with additional storage capacities of 14 and 12 billion cubic feet (Bcf), respectively. An additional improvement to the southern California infrastructure is the Kern River Pipeline Company's completion of the High Desert project that will transport 282 MMcfd of natural gas from the Kern River pipeline to the High Desert power plant in Victorville, California.

Provided below is the Energy Commission staff's assessment of the adequacy of these expansion projects. The analysis addresses annual average conditions and does not represent any seasonal or short-term variations in the market. Due to a drought or an extremely cold winter, increased demand for natural gas may exceed the receiving and storage withdrawal capacity. The staff did not analyze the adequacy of the receiving capacity in California under such adverse conditions. To meet seasonal changes in natural gas demand and account for adverse year conditions, the CPUC typically requires utilities to maintain some excess receiving capacity, normally about 20 percent above the average annual daily demand. This extra capacity is known as "slack capacity."

Figure 13: Kern River and PG&E GTN fInterstate Pipeline Capacity Compared to Forecasted Flowing Supply

Source: California Energy Commission

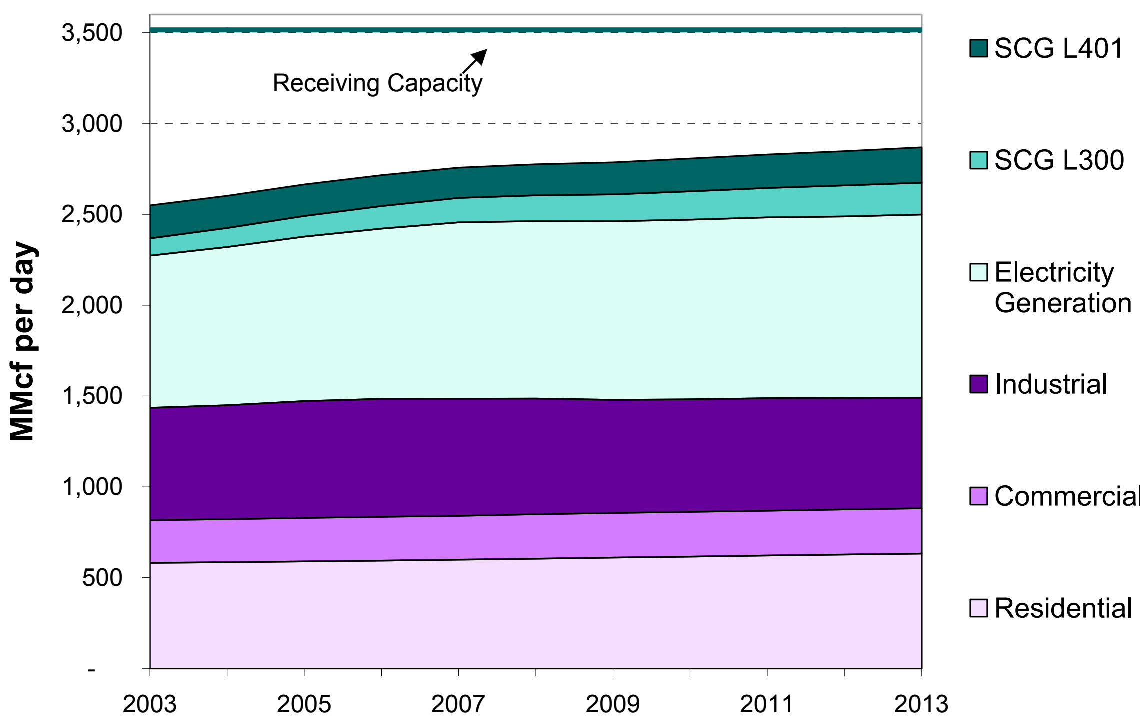


PG&E Receiving Capacity

The Energy Commission compared average daily demand for the PG&E service area with the receiving capacity of the system. The demand assumes average weather conditions and availability of hydroelectricity (see **Figure 14**). A notable portion of the demand would be delivered to SoCal Gas from PG&E via the Wheeler Ridge inter-tie.

Figure 14: Projected Natural Gas Demand Compared to PG&E's Supply Receiving Capacity

Source: California Energy Commission



PG&E delivers supply to SoCal Gas from the southwest through its Baja Path (Line 300) and from Canada via its Redwood Path (Lines 400 and 401) (by displacement). The receiving capacity at 3,400 MMcfd includes PG&E's 200 MMcfd addition to its Redwood Path and the in-State production delivered to the PG&E system.

During the next ten years, the natural gas demand for electricity generation may constrain pipeline receiving capacity on the PG&E system. Up until 2006, PG&E will have about 20 percent in slack capacity. By 2013, approximately two percent more capacity above the current available level is needed to meet all the utility customer needs on an annual average basis. With very low levels of slack capacity, PG&E may lose flexibility to meet seasonal changes in demand and may not be able to fill its storage facilities, which could lead to the potential of curtailments and natural gas price volatility.

To meet PG&E's need for increased receiving capacity, several alternatives exist:

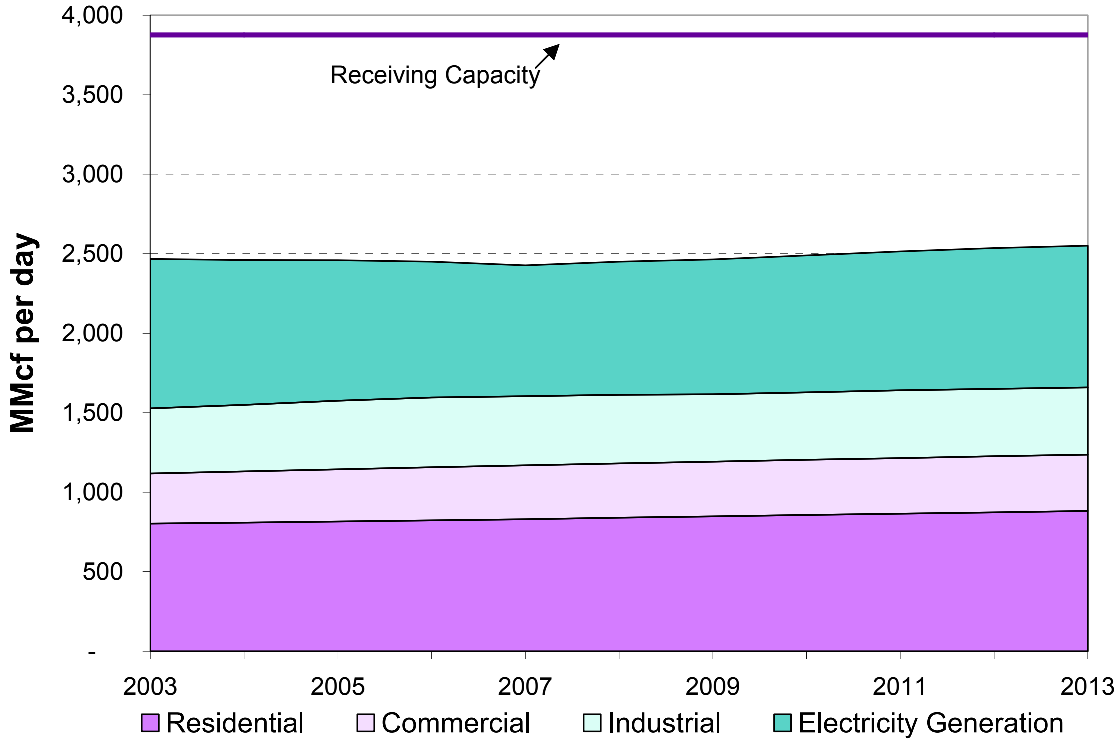
- **Redwood Path and Baja Path.** To meet future demand, this analysis indicates that both of PG&E's mainline pipelines fill to capacity by 2013. The capacity of the Redwood Path (Lines 400 and 401) was recently expanded, increasing PG&E's ability to receive additional natural gas supply from Canada. More expansions to this path would be beneficial. Additionally, the Baja Path (Line 300) could be expanded to receive additional supply from the Rocky Mountain and southwestern regions.
- **Ruby Pipeline.** El Paso's Colorado Interstate Gas Company could build the proposed Ruby Pipeline that would extend from the Rocky Mountains to Reno, Nevada, and then to the Yuba City, California area. Pipeline capacity to California would be 500 MMcfd with availability in 2006 or later.
- **Expanding Storage.** Expanding storage facilities and increasing the ability to cycle natural gas more frequently can significantly improve system flexibility in the PG&E region. Wild Goose Storage, Inc. has obtained the required permits to expand its facilities to 29 Bcf by July 2004. Also, the Lodi Gas Storage facility (Western Hub Properties) is now operating at its full capacity and providing additional storage capacity and balancing operations in Northern California. PG&E is also planning to increase capacity at its McDonald storage facility by an additional 6.5 Bcf by July 2004.
- **LNG Development.** LNG receiving terminal development could deliver additional gas to the PG&E system. Calpine Corp. recently indicated in the press that it seeks partners to build an LNG facility in the port at Eureka, California. Such a project could fuel a local power plant and deliver additional natural gas to PG&E's Redwood Path pipeline as early as 2006. An LNG receiving terminal and gasification plant proposed by subsidiaries of Bechtel Corp. and the Royal Dutch/Shell Group of Companies at Mare Island in Vallejo, California was cancelled in early 2003.

SoCal Gas Receiving Capacity

The Energy Commission compared the daily demand for the SoCal Gas service area with the receiving capacity of the system (see **Figure 15**). The demand assumes average weather conditions and availability of hydroelectricity. This assessment accounts for the SoCal Gas eceiving capacity that is used for deliveries from the interstate pipelines into the SDG&E service area. As with the PG&E service area, electricity generation is the primary cause of rising demand in southern California.

Figure 15: Projected Natural Gas Demand Compared to SoCal Gas's Supply Receiving Capacity

Source: California Energy Commission



After 2001, SoCal Gas completed an extensive program to increase its natural gas receiving capacity from 3,500 MMcfd to 3,875 MMcfd. This includes in-state natural gas production delivered into the SoCal Gas system. Through the next ten years, the recent program of expansions will provide slack capacity that exceeds the forecasted annual average daily natural gas demand. Slack capacity in the SoCal Gas service will range from 67 percent in 2003 to 39 percent in 2013. Using a greater portion of the storage capacity at the SoCal Gas Aliso Canyon and La Goleta storage facilities will allow SoCal Gas to meet peak day requirements.

The excess receiving capacity in the SoCal Gas service area allows for increases in demand beyond what is presented in this assessment. Staff believes that this receiving capacity may be needed if basecase assumptions regarding new power plant development are not fulfilled. Southern California is in the position to receive electricity from many of the proposed new generation faclities in Arizona or facilities built in the lower San Joaquin Valley. If the power plants outside of the SoCal Gas service area are not built as presumed in the basecase, or the new electricity is needed to meet demand elsewhere, then there will be a need for more natural gas-fired power generation in the SoCal Gas service area to meet the local electricity demand. The excess receiving capacity shown here could be used to meet the increased demand for gas-fired electricity generation.

In summary, the primary infrastructure concern is the delivery capacity of the interstate pipelines to SoCal Gas. As illustrated above, natural gas supply from the southwest corridor may be constrained by pipeline capacity in the northern portion of the corridor across Arizona. Access to the limited pipeline capacity is complicated by a growing demand for natural gas in Arizona and Mexico, and the dispute related to shipping contracts on the El Paso Natural Gas Company pipeline system. Until new pipeline capacity is built and the shipping contract dispute is resolved, southern California could lose natural gas supply to upstream demands. Current projects that can provide relief to future constraints is the Silver Canyon pipeline proposed by Kinder Morgan. With the FERC's ruling on the 'full requirement' contract conversions, customer interest for new capacity along this corridor could create a need for a new pipeline, providing the sought relief to the upstream section of El Paso's northern corridor.

Natural Gas Storage

Natural gas storage plays a very significant role in ensuring reliability of supply to meet the demands of customers. In the regulated environment of past years, storage was a bundled commodity with other natural gas transactions. Since 1992, with deregulation of the natural gas commerce, storage for a consumer such as an industrial or power generation consumer can be purchased separately and in a manner that is appropriate with their use and need. The utility distribution companies continue to provide storage as a bundled product to residential and commercial customers.

Natural gas can be stored in a number of ways. The most common method is to store it under pressure in underground facilities. Commonly used facilities include (1) depleted reservoirs in oil and gas fields, (2) aquifers, and (3) salt cavern formations. The quality of the facility and the quantity of gas that can be stored in each of these facilities varies depending on the physical characteristics such as porosity, permeability, and retention capability, and economics or costs involved in storing the gas. The basic characteristics of an underground storage reservoir are its capacity to hold natural gas and the rate at which gas can be injected or withdrawn, representing the ability of its injection or deliverability rate.

Natural gas can be stored in two additional ways, other than in underground storage facilities. Above ground storage tanks can be used to store natural gas, typically like the tanks used for storing liquefied natural gas (LNG). The second and most common method to store gas for short periods of time is in the pipeline itself. This is commonly referred to as 'line pack' where the amount of gas in the pipeline is increased by increasing the pressure in the pipeline. During surges in gas demand, the additional gas in the pipe is used to supplement normal pipeline availability.

Generally, natural gas suppliers and consumers use storage in two ways. First, gas storage is used to supplement gas supplies when demand exceeds production or capacity to deliver through pipelines. This use can be on a regular basis, like a baseload demand component or as a peak load supply to provide high volumes of natural gas for short duration as needed during peak times. Second, storage is used to hedge prices. The purpose of gas storage provides a smoothing of natural gas supply and demand along with price fluctuations.

This section provides a general description of California's natural gas storage system and its usage. The discussion also includes a description of 2002-2003 winter's storage use with implications of effects for the next 12 month period.

California Natural Gas Storage

Natural gas production is typically maintained at a relatively steady pace over time. The demand for or, consumption of gas normally peaks in the winter to meet space-heating needs. Over the past few years in California, a second, smaller peak in consumption has occurred to fulfill the demand for gas in power generation. The balance between a steady production and varying demand is met by a combination of gas flow via pipeline and storage systems. During times of low demand, usually in spring and autumn seasons, natural gas from the pipelines is used to fill the storage facilities. During summer and winter consumption, both the pipelines and storage facilities are used to meet the demand peaks, with storage complementing any quantity demand in excess of what is supplied by the pipelines.

The hedging of natural gas prices is accomplished by natural gas users buying gas when priced low and avoid paying higher prices sometime in the future. Likewise, gas suppliers can also hedge their production by putting gas into storage during times of lower prices and then sell the gas at some stage in the future when prices are better.

Customers of natural gas storage use capacity differently. In general, natural gas storage is broken into three categories: inventory, injection, and withdrawal capacities. Core customers purchase a certain level of these storage services to meet peak winter space heating needs. A small portion of these services is allocated to the natural gas utility for pipeline balancing activities. The remainder is available for Noncore customers, such as industrial users and electric generators to meet its variable consumption patterns and possible to hedge prices.

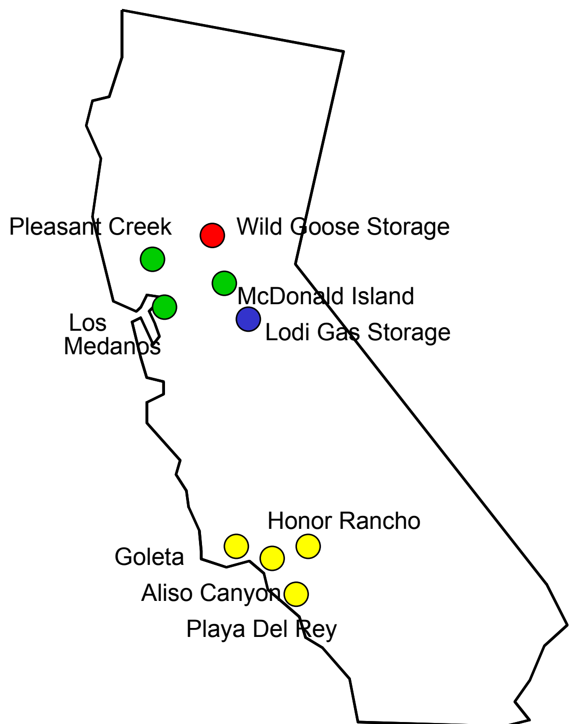
Table 9 below shows location of storage facilities in California. In Northern California, three companies own storage facilities. At the gas utility level, PG&E has three separate fields it uses to meet its customer's needs. Two more storage facilities are also located in Northern California with one field each. These two facilities, Wild Goose Storage and Lodi Gas Storage, are privately owned. The SoCalGas utility has four fields located in Southern California. Locations of each storage field are found in **Figure 16**. A fifth field, the Montebello Storage facility, owned by Socal gas Company, was abandoned in 2002 and no longer provides any storage services, and is not indicated on the map. SDG&E on the other hand has no storage facility in its territory, and depends totally on pipeline flows to meet the seasonal demand.

Table 9: California Natural Gas Storage Facilities

Storage Facility Name	Working Gas Capacity (Bcf)	Maximum Withdrawal Capacity (MMcf/d)	Maximum Injection Capacity (MMcf/d)
PG&E	* 98	1,534	375
SoCalGas	120	3,200	800
Wild Goose Storage[1]	14	80	200
Lodi Gas Storage	12	500	400

* For the PG&E storage system, the 98 Bcf includes both cycling and non-cycling working gas capacity.

Figure 16: Natural Gas Storage Facilities Map



Winter 2002-2003 Natural Gas Storage Use

The large draw down of California's natural gas storage this past winter surprised many observers, given that the Western U.S. experienced moderate-to-warm temperatures throughout the heating season. The rest of the nation, however, experienced a more severe winter than the West. During the past winter and into early spring, extreme cold

[1] The Wild Goose Storage facility is expanding its facility, with Working Gas Capacity increasing to 29 Bcf, maximum injection capacity to 450 MMcf/d, and maximum withdrawal rate to 700 MMcf/d.

temperatures in the eastern half of the continent forced the rapid depletion of natural gas storage inventories, which reached a record low of 623 Bcf during the second week of April.

On November 1, 2002 California entered the heating season with nearly 100 percent of its 243 Bcf of natural gas storage capacity filled. By the third week of March 2003, storage inventories reached a nadir, around 90 Bcf, because many storage customers withdrew gas from storage throughout the winter to avoid paying higher prices demanded by pipeline flows. With April 1, 2003 marking the beginning of the traditional storage injection season, California storage customers have made some headway towards replenishing inventories.

The end of May 2003 marked the second consecutive month of healthy natural gas storage injections in California. Net injections for the month were 35 billion cubic feet (Bcf), bringing inventories to 146 Bcf. By comparison, May injections during the past five years averaged 21 Bcf. California's gas storage customers have added about 56 Bcf to storage since statewide inventories reached the season-low level of 90 Bcf in March 2003. California's storage facilities have a combined capacity of 243 Bcf.

Storage levels, as of June 2003, are shown in **Figures 17 and 18** for Northern California and Southern California respectively. Northern California level includes PG&E, Wild Goose Storage, and Lodi Gas Storage inventories. The Southern California level represents gas in SoCalGas' storage fields. **Figure 19** shows the monthly trend in California's total storage inventory levels.

Figure 17: Northern California Storage Inventory

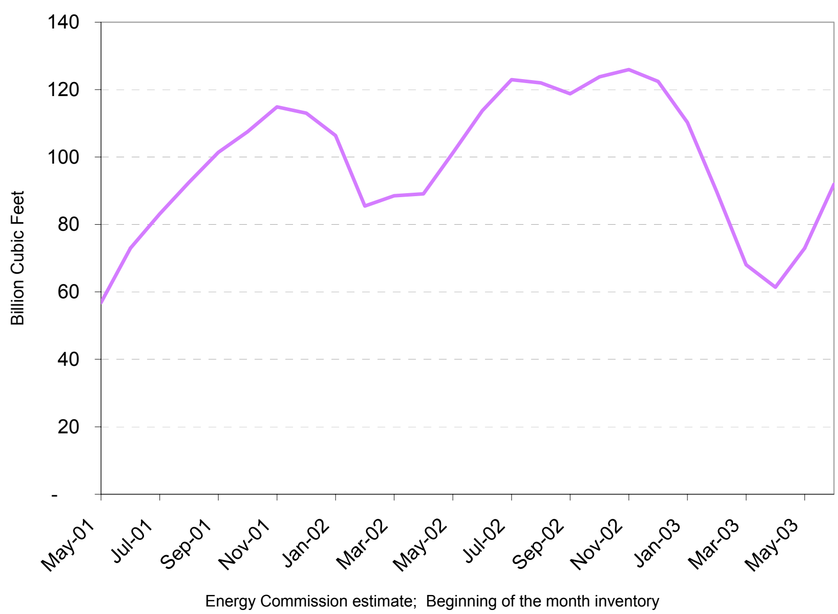


Figure 18: Southern California Storage Inventory

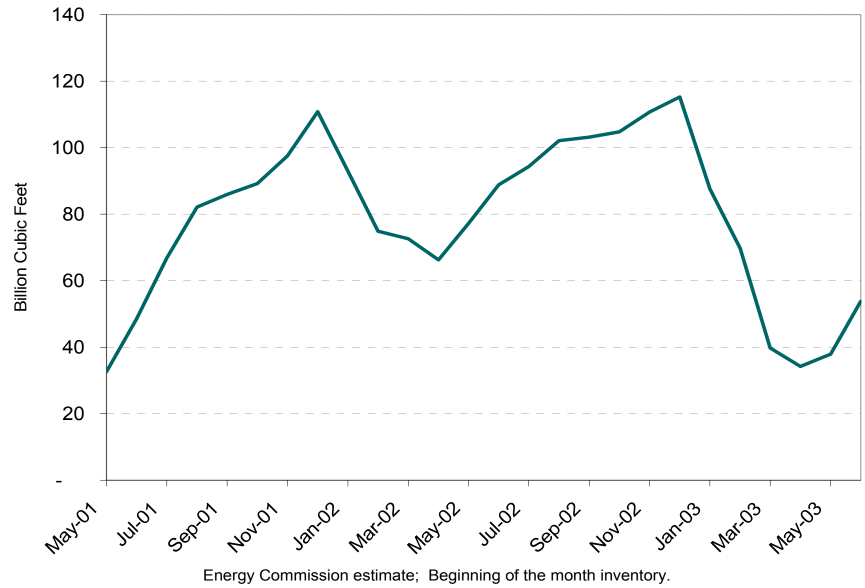
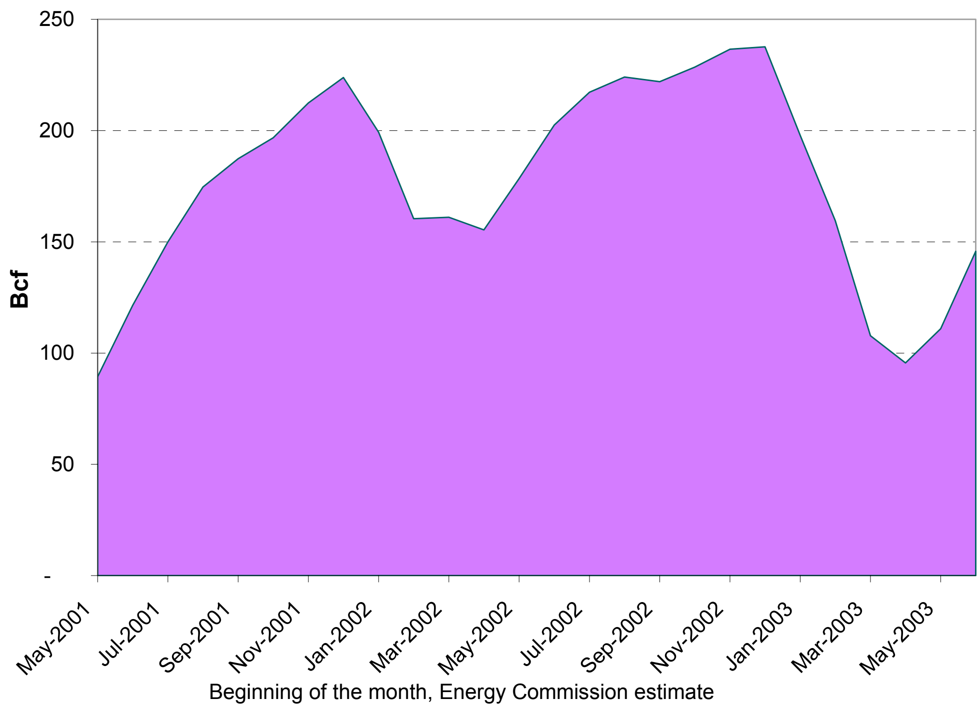
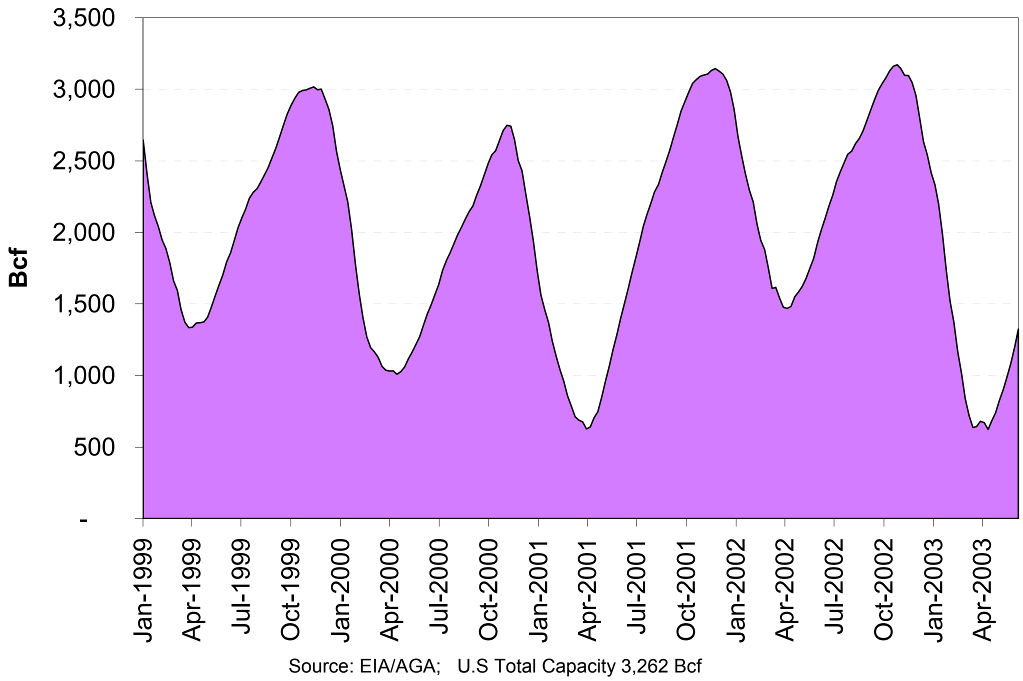


Figure 19: California Storage Inventory



The severe cold snap during the winter of 2002-2003 on the Eastern states contributed to a significant depletion of storage levels. According to the U.S. Department of Energy, Energy Information Administration, national inventories were 1,199 Bcf on May 30, 2003, compared to 828 on May 2, 2003, for a net injection of about 371 Bcf during May. **Figure 20** provides U.S. storage inventories through May 2003. While much focus and concern has been placed on national gas storage levels, which reached record lows last April, some national analysts believe that it is feasible for nationwide natural gas storage to reach the desired level of around 3 trillion cubic feet by November 1, 2003, based on recent rates of injection. However, this task may be made more difficult if this summer is warmer than normal or if hurricanes disrupt natural gas production in the Gulf of Mexico, as happened last fall.

Figure 20: U.S. Storage Inventory



Many observers, including the Energy Commission, are concerned that the challenge of making large storage injections over the coming months could go, at least partially, unmet. The California Public Utilities Commission requires California gas utilities to store specific amounts of gas, which varies by utility, prior to November 1 to ensure that each utility can meet their core customers' winter needs. On the whole, this amounts to about 70 percent of the utility-owned storage capacity in California. However, unregulated storage customers, such as power plant operators and large industrial customers, are not required to store a minimum amount of gas. This exception could become an issue if unregulated customers expect that natural gas prices next winter will be cheaper than the current spot market prices, based on a comparison of natural gas spot market prices and the NYMEX futures price for natural gas deliveries next winter. These customers might choose to defer gas purchases until next winter when they believe gas will be less costly, rather than store gas this summer. While this approach might be a sound business strategy for a private company to manage fuel costs, it provides the state with little assurance against tight natural gas supplies next winter. This situation could become exacerbated if the summer of 2003 is much hotter than normal. If this is the case, natural gas-fired power plants will operate more frequently, increasing demand for natural gas and resulting in higher summer gas prices. The Energy Commission, as well as other agencies such as the California Public Utilities Commission, will continue to monitor California's natural gas storage levels closely.

CHAPTER 3: SCENARIOS

Scenarios

The basecase assessment described in the previous chapter represents the best estimate of the behavior of the natural gas market over the next ten years. This assessment uses a specific set of assumptions about demand, natural gas resources, transportation rates, and pipeline capacities. However, majority of the input parameters included in the assessment has uncertainty tied to them. The observed volatility and sudden spikes or troughs indicate this uncertainty in market prices and supply availability. One way to include the assessment of uncertainties in the market place is to conduct scenarios and sensitivities to test the impact of one or more variables on the assessed price and supply availability. Staff implemented this scenario approach by changing one or more input variables to assess their impacts on the natural gas price and supply forecast. The scenarios designed also examine how different market conditions influence the price and supply of natural gas. To test the robustness of the basecase projections staff developed eleven scenarios in addition to the basecase that can be categorized under demand, supply, and the integrated price and supply outlook (IPSO) scenarios. The next section describes the scenarios designed and analyzed under the three categories along with their impacts on natural gas market behavior and price trends.

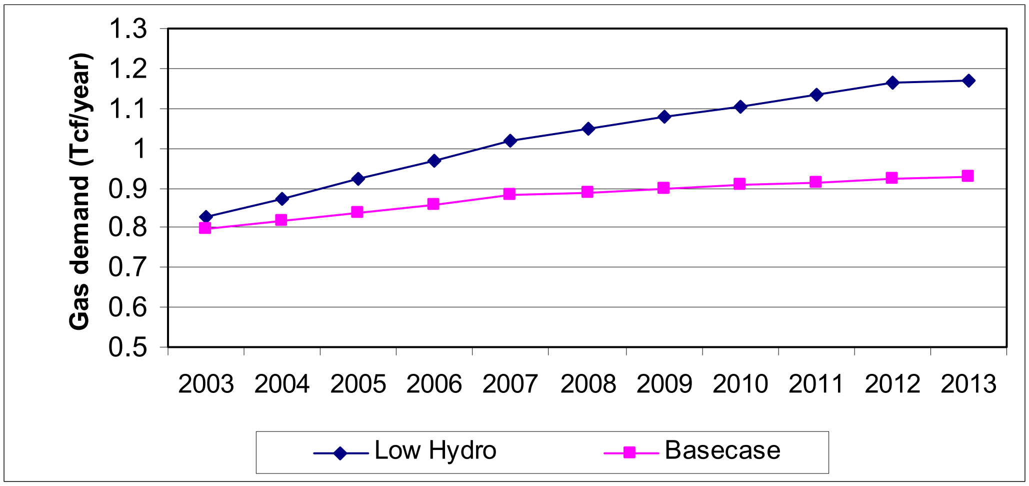
Demand Scenarios

The basecase assumes a projected natural gas demand over the next 10-year period. The demand in each market sector will depend on a variety of market fundamentals that can change in the future depending on market behavior. The following demand scenarios look at changes in market behavior that can result in different demand trends over the next 10-year period.

Low Hydro-generation

This scenario examines the price and supply impacts of a lower than normal rainfall or drought conditions in the WECC region. It assumes that California and the Pacific Northwest region experience below normal precipitation conditions resulting in low hydroelectricity generation, thus resulting in an increase in natural gas demand projections in the power generation sectors in the WECC region. **Figure 21** compares the gas demand for power generation in the low hydro scenario and the basecase.

Figure 21: Natural Gas Demand for Power Generation in California



Results for Low-Hydrogeneration Scenario

Analysis indicates that increased gas demand for power generation does not exert much influence over the gas price as, on an annual basis, the incremental gas demand under the assumed conditions is not very large compared to the quantity of gas consumed in the state.

However, it should be noted that this analysis is based on annual average numbers. A low-hydro generation scenario will impact the peak cooling days during summer when the stress on power generation needs is the greatest. Hence a short-term analysis addressing short-term price movements due to high utilization of gas pipeline capacities and storage operations on the increased need for gas in the power generation sector should be conducted to analyze this scenario further.

In this scenario, staff assumed that the low hydro conditions persist throughout the assessment horizon, which is not an expected outcome under even severe conditions. In the Electricity Infrastructure assessment, the low-hydro-generation conditions are assumed to occur for only a one-year period, unlike this scenario description[viii]. Under those conditions, the impact of the increased generation on long-run prices will be even smaller than noted here.

High Economic Growth

In times of high economic growth, natural gas demand will increase as industries demand more energy to operate their plants and equipment, in response to increased demand for products by consumers. The high economic growth scenario analyzed by the Demand Analysis Office (DAO) of the Energy Commission addresses the impact of a more robust economy on energy demand.

To model the effects of a stronger recovery on energy demand, the employment forecast was accelerated to achieve new forecast with an annual growth of slightly more than 1 percent higher than basecase assumptions for the years 2004-2007. After 2007, it was assumed that the baseline forecast trend continued. The DAO analysis determines California's demand projections for natural gas use in all sectors other than for power generation. The demand for electricity generated in the high economic growth scenario was input into the electricity infrastructure assessment work to determine the natural gas demand for power generation in California and the neighboring states. The combined natural gas demand was then input into the NARG analysis to determine the impact of high economic growth on natural gas price and supply availability in California and neighboring states.

Low Economic Growth

This scenario mirrors the previous scenario, in that, it assumes that the economic growth is worse off compared to the basecase.In the low economic growth scenario, the forecasted growth beginning in 2004 is delayed by one year so that growth on average is almost 1 percent lower than the baseline economic forecast. This scenario also determines the electricity demand in California, with which the natural gas demand for power generation is assessed. The combined natural gas demand is then input into the NARG model to determine the impact of this scenario on natural gas price and supply availability. **Table 10** summarizes key economic drivers and their assumptions in the high and low economic growth scenario.

Table 10: Comparative Growth Rates of Baseline and Scenario Forecast Assumptions
Average Annual Growth Rate (%)

	2003-2007			2007-2013		
	Basecase	Low Economic Growth	High Economic Growth	Basecase	Low Economic Growth	High Economic Growth
Real Personal Income	3.6	2.3	4.9	3.3	2.7	2.8
Employment	2.4	1.1	3.5	2.0	2.3	1.7
Industrial Shipments	2.2	1.4	4.9	3.4	2.8	3.0

Energy Efficiency and DSM Scenarios

The natural gas demand projections for power generation used in the model assume an average amount of demand side management (DSM). This scenario evaluates the impact of higher than average demand side management, which places downward pressure on gas demand. Natural gas and electricity demand projections in the basecase reflect the assumption that current levels of funding for utility energy efficiency programs will continue. Two scenarios were designed to study the impact of higher and lower DSM program levels as compared to the basecase.

The High DSM scenario estimates the impact of roughly doubling spending on energy efficiency programs for the residential and commercial sectors. Increasing spending on natural gas efficiency to $233 million per year from $102 million per year (based on average spending 1999-2000) reduces demand by about 103 million therms in 2013 (equivalent to about 30 million cubic feet per day).

The Low DSM scenario assumes that no utility energy efficiency spending continues after 2003. As in the previous scenarios, the staff determined the impact of lower DSM levels on electricity and natural gas demand. The natural gas demand for the residential and commercial sector and that for the generation sector were used in arriving at the impacts of energy efficiency impacts on natural gas price and supply. No data was available on industrial energy efficiency potential, and hence, industrial demand is unchanged in this DSM scenario.

Results for the Economic Growth and DSM Scenarios

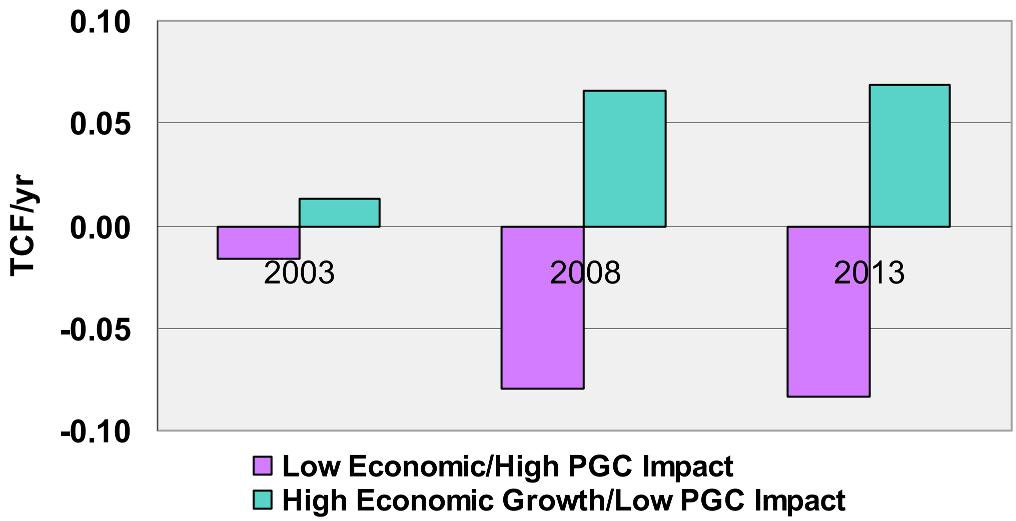
The above four scenarios on economic growth and energy efficiency and renewable measures result in changes in demand for natural gas in all the sectors. The high an d low economic growth scenarios result in changes to all sectors including the power generation as economic growth stimuli also impact electricity demand which in turn affects the demand for natural gas. The energy efficiency or DSM scenarios on the other hand only affect the power generation sector as DSM measures reduce electricity demand and thus gas demand for power generation and renewable resources substitute for gas fired generation and hence reduce gas demand. The DSM cases also provide the higher or lower demand for natural gas resulting from DSM and efficiency improvement programs for the entire WECC region. The details of the DSM and efficiency programs are documented in the Demand Assessment Office's Report. The changes in demand resulting from each of these scenarios are summarized below in **Table 11**.

Table 11: Demand Changes over the Basecase

Cases	Core & Noncore	Power gen CA	Power gen WECC
Low DSM	0.5%	13.0%	7.4%
High DSM	-2.5%	-9.6%	-6.5%
Low Econ growth	-2.0%	-9.0%	-9.0%
High Econ growth	2.6%	8.1%	7.1%

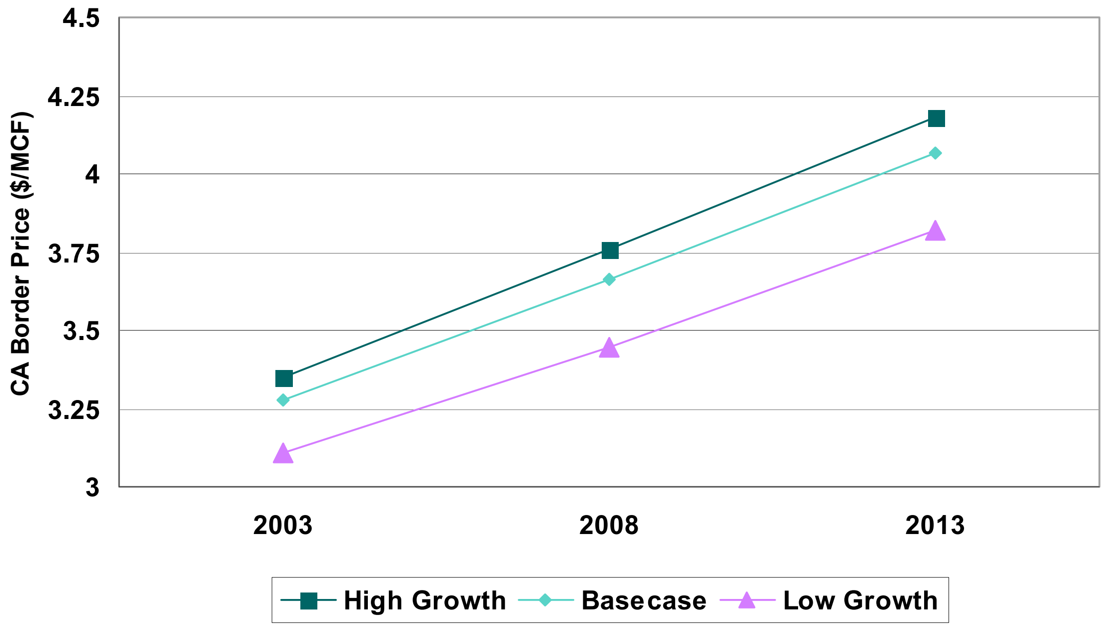
To capture the boundaries of these four scenarios, staff created 2 cases that include the extremes from each of the cases. These two cases will provide the impacts of the economic and/or efficiency parameters on the price and supply availability for natural gas in California. The low growth boundary assumes that the core and noncore demand is reduced by 2.5 percent while the gas demand for all power generation in US drops by 9 percent. The levels assumed for the high-growth scenario assumes an increase in gas demand of 2.6 percent in the core and noncore sectors and a 7.4 percent increase in the power generation in the US.

Figure 22: Change in Gas Demand for Power Generation - High/Low Growth and DSM Cases



As seen in the **Figure 22**, the total change in gas demand for the Power generation sector in California is not very significant compared to the total gas demand in California. The price impacts for each of the two boundary cases is shown in the above figure. The low DSM scenario or the high growth scenario does not increase the gas demand significantly enough to raise gas prices. By 2013, the price increases by about 2.7 percent above the basecase prices. On the other hand, the high DSM and low growth scenarios result in lowering the gas demand across all sectors and the price drop in this case is about 7 percent lower than basecase prices as shown in **Figure 23**.

Figure 23: California Border Gas Price for the High/Low Growth and DSM Cases

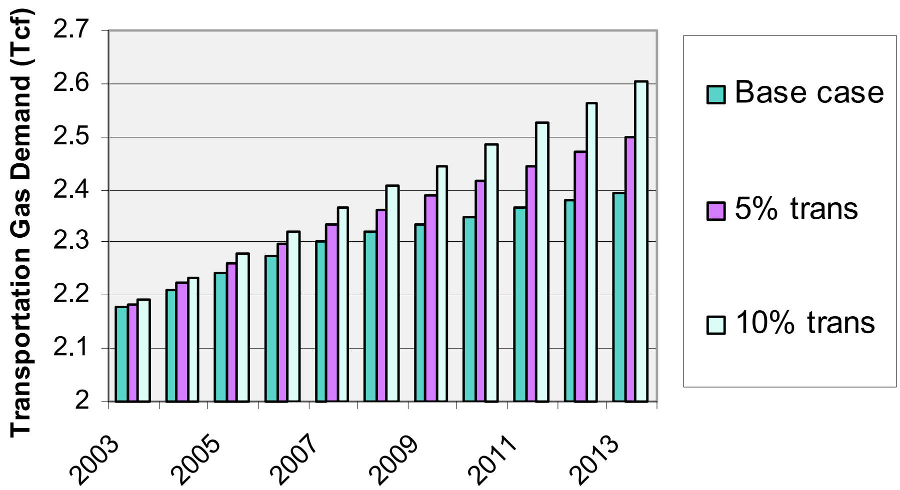


Natural Gas Use in Transportation Sector

Natural gas has become an increasingly important fuel in recent years because natural gas is the fuel of choice in most markets in the US. In fact, the main driver for natural gas growth is the electricity generation industry. In the future however, the transportation sector may also become increasing reliant upon this clean burning fuel, both for its direct use in natural gas vehicles (NGVs) and its potential indirect use in fuel cell vehicles (FCVs).

The assumptions contained in this scenario are based on the Transportation Energy Technology Division's work on the AB 2076 report. These scenarios are, in general, very aggressive. However, the motivation for this analysis is to look at a "high-impact scenario" where substantial natural gas demand from transportation sources evolves that could significantly impact both price and supply availability of natural gas in the market place. For this scenario, assumptions include that 7.6 percent of Light Duty vehicles, either directly (NGVs) or indirectly (Hydrogen FCVs), use natural gas. With heavy-duty vehicles, the assumption is that less than one percent of them use natural gas or hydrogen derived from natural gas. Overall, this amounted to about 5 percent of the total natural gas in the state by the year 2020. The estimates for NGV and FCV determined by Commission staff for California's transportation market was used (as a percent increase over the core residential and commercial demand) to account for increase in natural gas demand in the transportation sector throughout the U.S. as shown in **Figure 24**.

Figure 24: Impact of Natural Gas Use in Transportation Sector

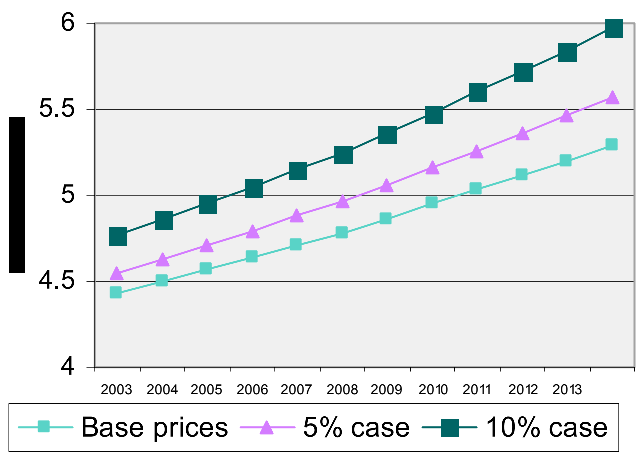


To further test the robustness of the natural gas market, the level of penetration of natural gas use in vehicles was increased to reach 10 percent of the state's demand by the year 2020. In this case, again, it was assumed that the rest of the US would also experience significant penetration in using natural gas driven vehicles, as assumed in California.

Results for the Natural Gas Use in Transportation Sector

In the case where penetration occurs to the extent of about 5 percent of the state's demand, the annual statewide system average natural gas price grows at about 1.9 percent compared to a 1.6 percent growth rate in the basecase. On a us wide basis, assumption of a healthy penetration of vehicles using natural gas as the primary fuel drives average well head prices up by about 4 percent compared to basecase prices as shown in **Figure 25**.

Figure 25: Impact of Natural Gas Use in Transportation Sector on CA System Wide Natural Gas Price



In the more aggressive case where the transportation sector demand for natural gas reaches 10 percent of statewide demand by the year 2020, the annual price growth rate increases to 2.1 percent. The annual average wellhead price rises by 10 percent above basecase prices in this scenario.

Supply Scenarios

Low Gas Supply (Resources)

The uncertainty of availability of resources has been a prominent issue for debate in the market place. Discussions indicate that majority of natural gas fields in the US and Canada have matured in their production life and that the natural gas production in the US will begin to decline within the time frame analyzed in this assessment. In fact, the industry view, regarding potential supply sources that can be produced, hinges on the pessimistic opinion that supplies will be tight over a longer term and that it will cost more to find and produce the natural gas to meet the growing demand. On the contrary, some entities hold that the new and unconventional resources that exist in abundance can economically be developed and explored. These unconventional resources refer to the coal bed methane deposits, shale and tar sands in the US and Alberta.

Results for the Low Supply Scenario

In this analysis, staff only considered the scenario where potential resources are lower than assumed in the basecase. The low resource availability is represented by lowering the proved reserve appreciation in the model. As discussed earlier, the reserve appreciation indicates the increase in available reserves over time. By lowering the reserve appreciation parameter to zero, Staff restricted the growth of all resources in future years.

Due to a restricted resource base the market needs will be met by more expensive gas resources and the cost to access these resources increase over time at a faster rate than assumed in the basecase. Annual average wellhead prices in the US increase by about 25 percent above basecase values over the next 10 years. The wellhead prices rise by about $0.60 to $3.60 per MCF in 2003. By the end of the forecast horizon, wellhead prices rise to $4.40 per MCF by 2013. With regard to supplies to California, market shares of Canada and domestic production do not change significantly while the loss in market share for the Southwest region is offset by increasing supplies from the Rocky Mountain region. The San Juan Basin, being a more mature basin, loses its market share to the relative new Rocky Mountain Region. California's statewide average price rises by nearly $1.00 per mcf by the year 2013.

As a result of increasing wellhead prices there is an increase in fuel switching from natural gas to alternative fuels in the four regions where fuel switching is assumed to occur (Mid Atlantic, South Atlantic, West North Central and West South Central census regions). **Figure 26** shows the market shares of natural gas and oil for the Lower 48 states over the assessment period. As noted, market share of oil increases from an average of about 4 percent in recent years to as high as 17 percent by 2013. Rising gas prices improve the economics for fuel switching in the specific demand regions in the lower 48 states.

Figure 26: Market Share of Natural Gas / Oil in Lower 48 States

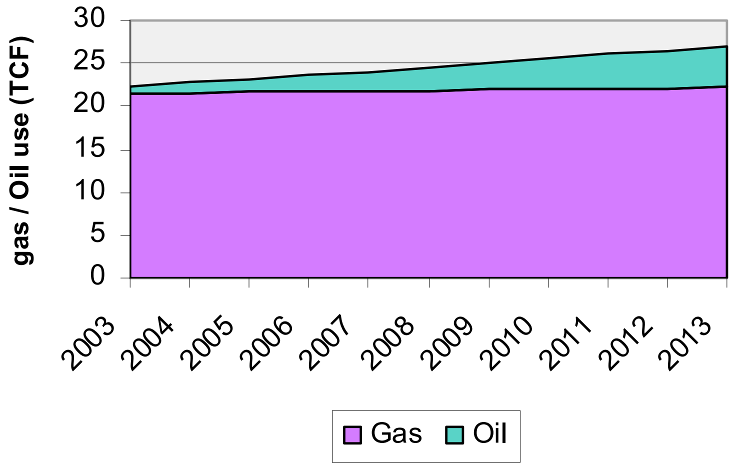
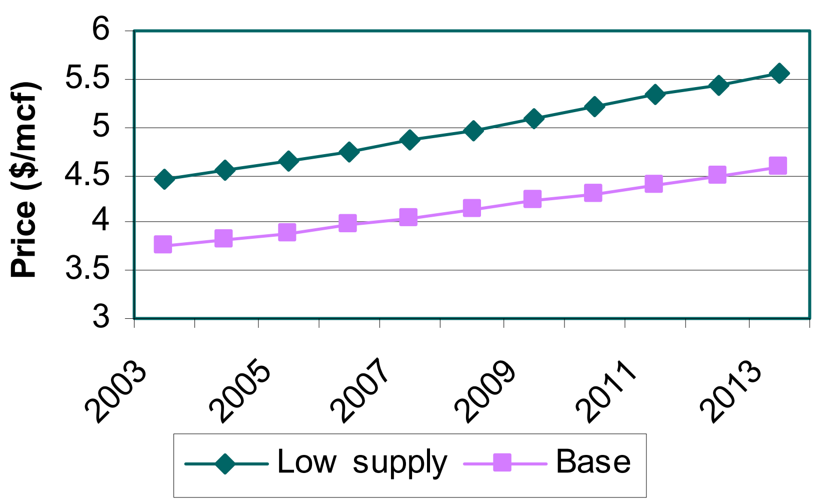


Figure 27 shows the US wide annual average natural gas price paid by power generation sector under basecase assumptions and compared with the low supply scenario. As shown, if natural gas supplies do not materialize as anticipated in the basecase assumptions, power generation prices will increase by about 20 percent above the basecase, over the assessment period.

Figure 27: Impact of Low Resources on US Wide Gas Price



Liquefied Natural Gas facilities on the U.S. West Coast

The potential for large quantities of LNG supplying California, Baja California and potentially even the Southwest Desert markets is gaining prominence. In fact, several companies have put forward proposals to build LNG facilities along the US and Mexico's West Coast. It is generally understood that LNG brought in to serve California markets will impact the State's infrastructure, natural gas consumption patterns and provide increased supply reliability to meet the growing demand. This scenario examines the impact of building three LNG facilities on the West Coast: one in Northern California, one in Southern California, and the third in Baja California, Mexico. While there are no final decisions to locate the LNG facilities at these locations, this scenario attempts to capture the infrastructure impacts on California and neighboring states if the LNG facilities are indeed permitted, constructed, and bring in significant quantities of LNG into the Western States. It is assumed that the capacity to import LNG from these three terminals totals to about 2 billion cubic feet per day. This scenario also assumes that the North Baja Pipeline reverses its flow directions and takes the LNG supplies from the Baja, Mexico to Ehrenberg AZ, where it interconnects with the El Paso's Southern pipeline system serving the Southwest Desert region, the Southern California Gas Company's backbone pipeline to serve Southern California markets, and the El Paso's bi-directional Lateral pipeline inside California. (North Baja pipeline currently serves markets in Baja California with gas supplies from the CA/AZ border point at Ehrenberg, AZ). The choice of the three locations is based on the fact that there are one or more proposals active in each of the three locations.

Results for the LNG Scenario

Literature survey provided information on cost estimates for construction of liquefaction facilities, transportation tankers and regasification facilities. In this particular scenario, the costs for landed LNG on the West coast was adjusted to ensure that the assumed three facilities operate at high load factors to investigate the impact of a large quantity of LNG imports on the pipeline infrastructure in the western US region.

Figures 28 and 29 compare potential LNG imports into the US under various scenarios. The projections for LNG imports on the West Coast assume that facilities will be built and operational by 2007 or 2008. Further, since the assumption in the analysis of the LNG scenario was to study impacts of LNG flowing into the Western States on natural gas pipeline infrastructure, the price at which LNG can come into the west coast market was adjusted lower to accommodate the desired flows.

Figure 28: LNG Imports along US West Coast

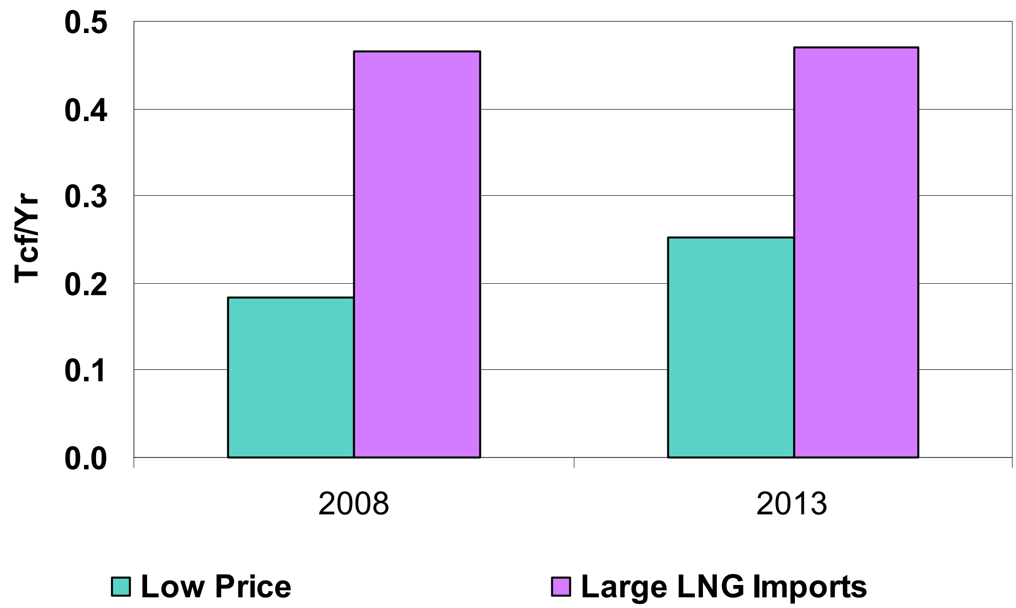
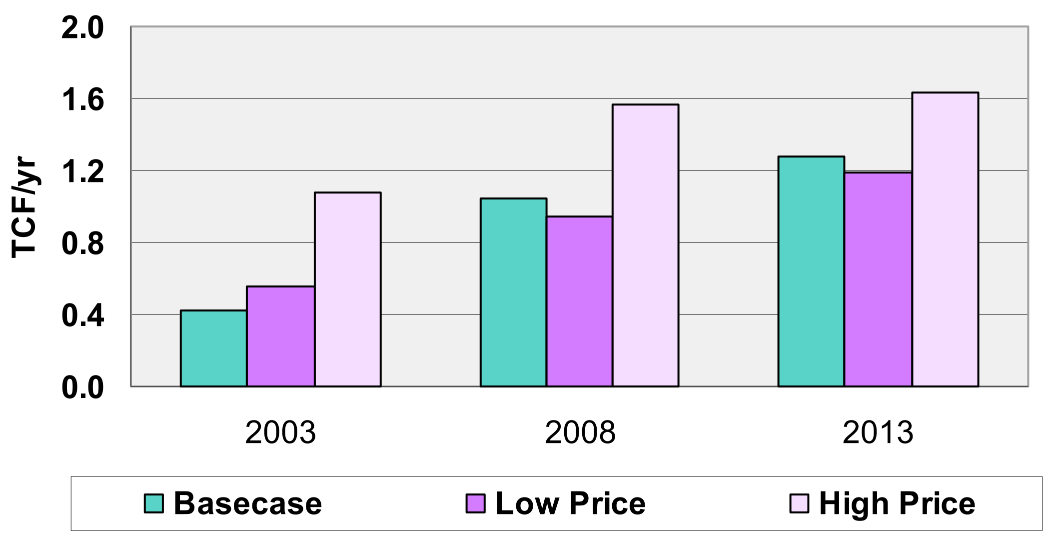


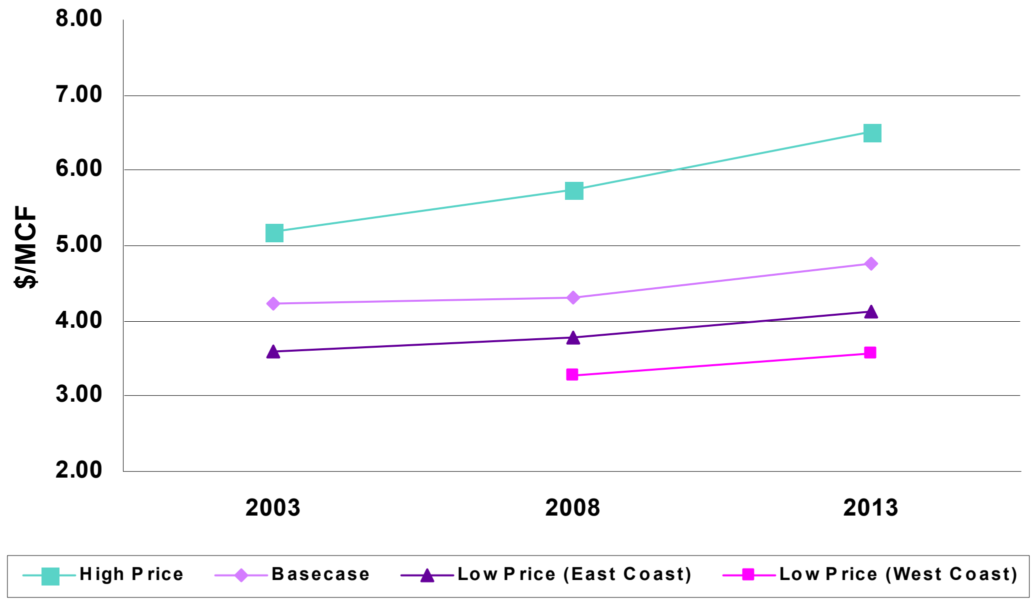
Figure 29: LNG Imports along US Gulf and East Coast



The East Coast continues to import LNG under all scenarios. LNG continues to be an economic option under the high price IPSO, with imports rising throughout the assessment period to satisfy the increasing demand. The low IPSO scenario also sees a growing demand over time for LNG, although imports are slightly less than those in the basecase. In the Low IPSO scenario, natural gas prices in the US drop significantly to be competitive with the LNG import prices. On the West Coast, the LNG Scenario was designed to provide large quantities of LNG at the three potential terminals.

Figure 30 shows prices of LNG on the East Coast for the Basecase and the two IPSO cases. The Figure also shows the price of LNG on the West Coast in the Low IPSO scenario.

Figure 30: Annual Average Price for LNG Imports



Liquefied Natural Gas Process Costs

North American natural gas markets can accept increasing amounts of Liquefied Natural Gas (LNG) to meet the growing demand. The Energy Commission has prepared a technical report on the costs associated with constructing and operating new LNG facilities throughout the world in order to understand the economic feasibility of bringing LNG facilities to the West Coast. The LNG process includes a number of elements that contribute to the overall capital costs in developing LNG operations. These components include: exploration and production; construction and operation of liquefaction plants; marine and pipeline transportation costs; and construction and operation of regasification terminals. These cost components are described in briefly below.

Exploration and Production Costs. Exploration programs find, and develop the necessary natural gas reserves to support LNG production. The LNG facilities recover the cost of LNG production and costs associated with finding and developing the natural feedstock. Typically, the exploration and production costs can range from 10 to 20 percent of the total project capital costs. The economic viability of finding and producing the natural gas reserves is critical to the long-term growth of the LNG industry.

Liquefaction Plant Costs. A typical liquefaction facility includes a liquefaction plant, natural gas storage, marine jetties, and loading facilities for LNG tankers. These costs depend on site-specific factors, as well as the scale of the project. Capital costs are estimated to be between \$300 and \$900 million for each one million metric tons of LNG liquefaction capacity (i.e., 133 million cubic feet per day of natural gas). Overall, the investment required for the liquefaction process can range between 25 to 35 percent of the overall capital costs of the LNG process.

Marine Transportation Costs. Shipping requires the use of specialized cryogenic tankers for transporting the LNG to market. The required number of LNG tankers for a project is dependent on the volume of LNG to be shipped and the distance to market. New LNG tankers have a capacity of 135,000 cubic meters and range between \$145 million and \$260 million to construct. The shipping component can range between 15 and 25 percent of the total capital costs of an LNG processing facility.

Regasification Plant Costs. A regasification facility includes a jetty for the LNG tanker, an unloading facility, vaporization units, and storage. The cost of a regasification import terminal depends on the storage capacity requirements, geology and seismic activity of the area, construction costs, availability of a deep-water port permitting and siting costs. The capital cost for the development of a regasification plant (1998 dollars) with a capacity of 500 million cubic feet per day is \$700 million. This is equivalent to approximately \$0.56 per million cubic feet, and can range between 15 and 30 percent of the overall capital costs.

Integrated Price and Supply Outlooks (IPSO)

Scenarios described above addressed specific variables or concerns in the natural gas market and provided the extent of impacts that each of these variables could exert on the market over the next ten-year period. However, we are also aware that the natural gas market does not experience these variables one at a time. In fact, the impacts of each variable can and do affect other variables. Hence it is important to investigate the effect of a combination of these variables on the natural gas market. Specially, given the close interaction of natural gas and electric markets, an integrated approach to designing the outcomes of future events influencing the gas and electricity markets is essential. Based on this perspective, staff developed two scenarios that include simultaneous changes of several parameters in the model. Critical input variables--natural gas resource potential, LNG availability, natural gas demand projections and the availability of alternative fuels competing with natural gas for market share formed the basis of parameter changes.

These two scenarios address the question of what would happen if events associated with model input assumptions simultaneously occurred. The selection of range of input parameters is intended to provide the boundaries for natural gas price in the market under the Integrated Price and Supply Outlook (IPSO) scenarios. Thus, the high and low IPSOs illustrate the possible extremes of annual average natural gas prices over the forecast horizon. It should be noted that while these extreme price levels are achievable on a short-term basis, they are not sustainable over a longer duration. The interaction of market forces and response to high or low prices, would tend to push supply and demand away from the extremes and toward the more plausible basecase.

Low Price IPSO Scenario: In this scenario, variables affecting the natural gas and electricity markets change over time in a way that they cause to lower natural gas prices. This scenario assumes a 'hi-tech' world with technology advances driving the natural gas market. As noted in the previous chapter, natural gas resource is a major driver behind natural gas prices. In this scenario, the advanced technologies are assumed to positively impact the ability of the gas industry to be able to extract more natural gas from the known and proved reserves. This is achieved by raising the proved reserve appreciation factor in the model by 33 percent above the basecase levels. This change effectively increases the amounts of natural gas that can be produced from known reserves and it does so at lower costs. While the advanced technologies will increase the amount of gas recovered from known resources, this scenario does not change the total amount of potential resources that are assumed in the basecase. It is assumed that technology advances result in abundance of natural gas supplies, including LNG resources. This scenario assumes that three new LNG facilities on the US West Coast will be in operation by the year 2007, in addition to the existing LNG facilities on the East and Gulf coast of the US. Further advances in end-use technologies will create greater efficiencies at all consumption points. This increase in efficiency places downward pressure on demand, but higher economic activity forces greater consumption. As a result, changes in natural gas demand net to zero. The ability to switch to alternative fuels resulting from clean and advanced technologies, in the coal and oil industry, will be available, but the perception of relative environmental implications continue to inhibit increased fuel switching in areas other than the four regions assumed in the basecase.

High Price IPSO Scenario: This scenario assumes that environmental concerns drive the markets and promote natural gas as the primary fuel even in areas where fuel switching ability is assumed under the basecase. This scenario assumes that none of the US regions permit switching from natural gas to any alternative fuel after 2007. This scenario also assumes a 'low-tech' world where R&D investment is limited, and the ability to draw more gas from known reserves drops compared to the basecase assumptions. The proved reserve appreciation factor is lowered by 25 percent from that assumed in the basecase. Also, environmental leadership increasingly bans any access to more of the oil and gas rich regions in the Rocky Mountain supply basin, reducing the resource potential in this supply region by about 11 percent. LNG import capability in the US is limited to the existing facilities, again due to environmental and safety concerns. Stronger dependence on natural gas, associated with lack of efficiency improvements in end-use applications, leads to increased demand for natural gas. World oil prices, in this scenario, reach $35 per barrel by 2007 and remain at that level over the forecast horizon. This assumption combined with heightened environmental concerns increases natural gas consumption throughout the US. This scenario assumes that gas consumption increases by about 10 percent above basecase levels by the year 2017.

Table 12 below compares assumptions in high and low price IPSO scenarios with the basecase.

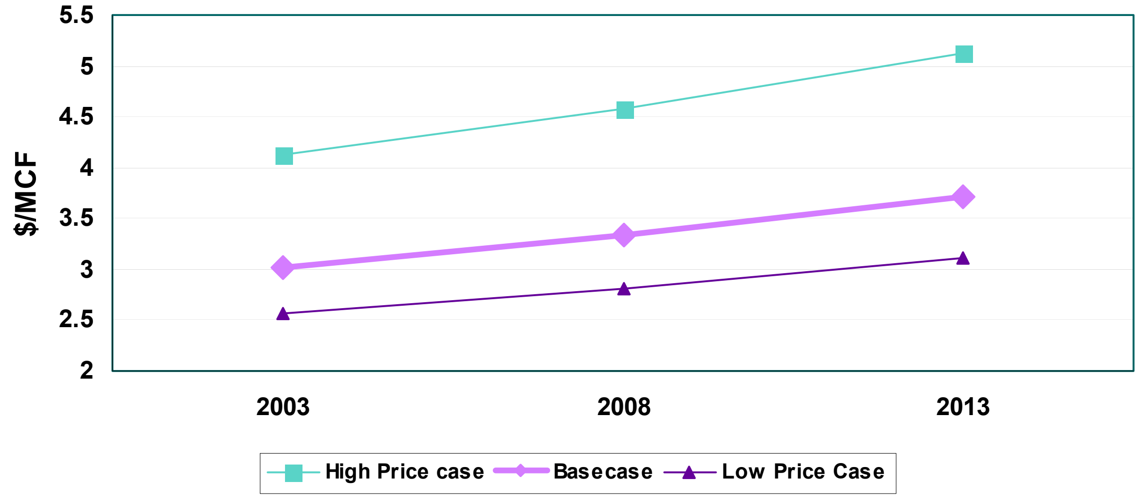
Table 12: Integrated Price and Supply Assessment Assumptions

Parameters	High Price Outlook	Basecase Projection	Low Price Outlook
NATURAL GAS RESOURCES			
Reserve Appreciation	Lowered by 25%.	Appreciation range: 0.03% to 2.2 %.	Raised by 33%.
Gas Resources	Land Access: 11% land restrictions in Rocky Mountains	Lower 48: 975 Tcf Canada: 417 Tcf	Same as basecase.
LIQUEFIED NATURAL GAS			
Liquefied Natural Gas	Same as basecase	Four facilities operating	Three facilities added: NorCal, SoCal, Baja
NATURAL GAS DEMAND			
Gas Demand	Low efficiency improvements. Step increase in gas demand, up 10% by 2017. 5% comes from demand in transportation sector.	Total US consumption by 2007: 23.99 Tcf.	High efficiency improvements. More total usage offset efficiency gains.
COMPETING FUEL SOURCES			
Oil Price	World oil prices rise to $35 per barrel by 2007, thereafter	World oil prices rise to $26 per barrel by 2007, then remain constant through forecast horizon.	Same as basecase.
Oil Burn	All states are constrained from switching to oil, by 2007	Switching allowed in four North American regions.	Same as basecase.

Results for the High and Low Price IPSO scenarios:

Figure 31 shows the price trends in the high and low price scenarios and compares them to the basecase projections. In the high price scenario, prices climb from $4.12 per MCF in 2003 to $5.12 per MCF in 2013. Prices in this scenario experience an annual growth rate of 2.2%. On the other hand, the low price scenario demonstrates a slightly lower growth rate, climbing at 1.98%. Prices in the low price scenario grow from $2.56 per MCF in 2003 to $3.11 in 2013.

Figure 31: Annual Average Lower 48 States' Wellhead Price ($/MCF)



In the low price scenario, Lower 48 production reaches 22.6 TCF in 2012, whereas, in the high price scenario, production grows to 26.8 TCF. The higher production results from the severe environmental constraints that lead to natural gas as being the primary fuel of choice throughout the US. **Figure 32** illustrates production levels in the two IPSO scenarios and the basecase. It is observed that the production of natural gas in the lower 48 states increase in both scenarios when compared to the basecase. The increase in production of natural gas in the low price case is due to the fact that as natural gas prices drop, the fuel switchability in specific regions of the US tends to use more natural gas than that used in the basecase. **Table 13** tabulates the price growth rates and compares them with the rate of the basecase.

Figure 32: Natural Gas Production in US (TCF per year)

Table 13: Annual Price Growth Rate, %

LoIPSO	1.98
Basecase	2.08
HiIPSO	2.19

Conclusions

This chapter discussed multiple scenarios that could result from various actions taken by governments, industry, utility and end-use groups over the next 10 years. The actions and behavior of the market players will significantly impact the natural gas market. While supply and demand will come into equilibrium at all times, short-term imbalances will occur specially during peak days when the system capacity will be stressed beyond its capacity. This analysis has focused on long-term implications and trends over the next ten-year period. Staff will be conducting a more detailed short-term market analysis during this year. Uncertainties in the market place will place stress on the supply/demand equilibrium that can result in higher and/or lower priced natural gas. The natural gas market is strongly linked with the electricity market and these two energy forms work in tandem in providing a balance between supply and demand for each of these energy sources.

The scenarios highlight implications of market fundamentals and provide critical information for future work. The growth and energy efficiency scenarios indicate that the impacts on price and supply of natural gas are not strong and that a larger deviation in these parameters will be necessary before they become a larger concern in the long-term trends of the natural gas market. The growth and efficiency factors, when addressed from a short-term or seasonal perspective can and will impact markets. Staff is currently working on developing a short-term market analysis to address seasonal and short-term impacts on the price and supply availability of natural gas in the state. Concerns about the supply deliverability from basins currently supplying natural gas to the state, and the potential to secure LNG supplies in California or via Baja, Mexico will be critical in determining the long-term natural gas market conditions.

The analysis conducted here focuses on long-term perspectives and trends in the natural gas market. Currently major concerns in the gas industry are from a short-term perspective of natural gas production levels and related drilling activities, pipeline capacity and storage facilities to buffer the swings in supply and demand during seasonal and peaking market conditions. This level of analysis requires staff to focus on short-term market fundamentals requiring monthly or even daily time periods as opposed to the current annualized analysis.

Though the analyses considers the integrated impacts of gas and electricity, the sections above discuss natural gas markets with emphasis. The details of the electricity assumptions and impacts on electricity infrastructure are discussed in great detail in an accompanying a staff document titled "Electricity Infrastructure Assessment" which along with this document will provide the framework for the Commission's Electricity and Natural Gas Report.

CHAPTER 4: IMPLICATIONS AND NATURAL GAS POLICY ISSUES

Introduction

This chapter discusses long-term technical and policy issues that need to be resolved in order to improve California's natural gas situation. The California Energy Commission staff has identified these issues based on its analysis of natural gas demand, supply, infrastructure, price, and market conditions. This discussion also reflects input for various stakeholders that have participated in public workshops sponsored by the Commission. The Energy Commission staff seeks additional comment from all parties potentially affected by this list of issues.

Policy Goal

In the natural gas area, the State of California's long term policy goal is succinctly stated: To ensure a reliable supply of natural gas, sufficient to meet California's demand, at reasonable and stable prices and with acceptable environmental impacts and market risk.

This goal provides what natural gas consumers need (reliable supplies at reasonable prices), what natural gas providers need (stable prices with acceptable market risk), and what the State of California needs (environmental protection and a healthy economy). This goal further requires that all these factors are balanced without specifying an absolute level for any single factor. For example, when balancing reliability, price, and market risk, consumers (or their regulated natural gas providers) may be willing to pay a slightly higher price than the minimum achievable in order to substantially reduce the risk of future price spikes.

Background Context

The long-term assessment provided in this report highlights several policy choices that the state needs to make. However, this long-term assessment cannot be considered in isolation without also considering the current conditions of California's natural gas demand, supply, infrastructure, price, and market situation. The California Energy Commission staff have summarized their observations of current market conditions below:

Demand

- Nationally, natural gas demand is exceeding domestic supply, and the deficit is growing each year.
- Californians are becoming much more energy efficient, with the average California household now using less than half of the natural gas as it did in 1975.

- California's total average demand is expected to decrease during the next few years, then increase, driven by thermal power plant gas consumption (often referred to as electricity generation demand, or EG demand).

Supplies

- There are adequate supplies of natural gas available to California for the next 10 years, on an annual average basis.
- California production has likely already peaked and is not expected to grow appreciably.
- U.S. production has not increased on pace with demand.
- New natural gas supplies are available, but at higher production costs.
- New production from unconventional sources is potentially very large, but uncertain as new technological advances are needed to increase production at reasonable costs.
- Increasing natural gas imports are the most likely strategy to ensure future supply meet future demand at reasonable and stable prices.
- Imports from Canada may not continue to grow to meet increasing U.S. needs.
- Liquefied natural gas (LNG) is expected to help meet the growing national gap between demand and supply.
- Uncertainty in EG gas demand in neighboring states creates uncertainty in the reliability of gas supply to California.

Infrastructure

- There is adequate pipeline infrastructure inside California to move gas to load centers, on an annual average basis.
- There is adequate pipeline infrastructure in Southern California to receive gas at the border through 2013, on an annual average basis.
- There is adequate intrastate pipeline infrastructure in Northern California to receive gas at the border and meet a 20 percent slack capacity planning criteria only through 2007, on an annual average basis.
- There is inadequate pipeline infrastructure outside of California (often referred to east of California, or EOC) to meet both California's needs and the rapidly-growing EG demand in Arizona and Baja Mexico.
- There may not be adequate natural gas pipeline and/or natural gas storage infrastructure to meet extreme winter peak daily demands.
- The determination of pipeline and storage infrastructure capacity needs was based on earlier, more stable market conditions and rules that allowed curtailment of customers with alternate fuel capability under short supply conditions.

Markets

- Natural gas wellhead and market prices are increasing.
- Short-term natural gas market prices are highly volatile, and much more volatile than in the past.
- Longer-term market prices and conditions may remain volatile.

Natural Gas Policy Issues

After reviewing the information available to it, the California Energy Commission staff have identified the following key policy issues which need resolution. Action on these issues is needed soon to help restore California and its natural gas consumers to a healthier long-term future. While these issues are focused on longer-term issues, their resolution may provide benefits in the short-term as well.

Overall Theme for Issues

Theme: Is California adequately managing all possible challenges that might prevent it from continually achieving its energy goal for the natural gas area?

Corollary Theme: Is California actively pursuing all reasonable actions to achieve an optimum energy goal for the natural gas area?

The theme for this report focuses on risk and uncertainty identification, assessment, and management. The staff's long-term reference-case forecasts assume reasonable, average conditions affecting natural gas demand and supply. The staff assumes that participants in the natural gas industry will act in a reasonable manner and make their decisions on infrastructure investment and operation in a manner consistent with fundamental economic principles. Staff assumes that short-term economic dislocations will be resolved and not affect long-term trends and that regulatory policies and decisions will guide this development in a balanced and efficient manner.

However, it is not likely that all these assumptions will prove correct at all times. Further, some actual future conditions may seriously threaten the State's ability to continually achieve its goals in the natural gas area. Therefore, the staff needs to consider recommendations for additional action that the State should take in order to ensure it achieves the State's policy goals. The staff are conducting analyses that will examine variations in key factors affecting potential natural gas demand, supply, price, and infrastructure. This scenario analysis is an effective tool to help provide insight on the importance of each of these key factors in the reference-case forecast and help narrow the discussion of potential actions that might be needed to ensure the State achieves its policy goals. The following section discusses some of those issues.

A. Demand Issues

1. Potential long term increases in demand from natural gas fired electrical generation create a significant risk of exposure to gas price volatility for California markets/customers.

2. Potential short term variability in demand due to weather, business cycles, and other uncertainties may exceed the capability of the state's infrastructure to meet all customers' needs.
3. Potential risks be mitigated with appropriate strategies only if identified, planned for, and acted upon.

Demand Questions:

a) Should the State of California pursue an even higher level of energy efficiency goals, and related programs, that would help reduce natural gas demand?

b) Should fuel switching capability be considered for electric generators and large industrial consumers during periods of constrained supply?

c) Should the Renewable Portfolio Standard programs be expanded further to reduce demand for natural gas fired electric generation?

B. Supply Issues

1. North American natural gas production appears inadequate to meet current and future demand.

2. It is uncertain where California will find all its needed supplies at reasonable and stable prices.

Supply Questions

a) Should the State take additional actions to incent enhanced production of instate natural gas resources, consistent with the State's environmental protection goals?

b) Does LNG offer enough benefits to California to outweigh its potential impacts and support a state policy recommending its use?

c) Should the State act as a broker or facilitator and establish government-to-government relationships with natural gas supply states and regions?

C. Infrastructure Issues

1. New power plant construction in the Southwest may jeopardize the reliability of natural gas deliveries to California.

2. It appears that natural gas infrastructure is inadequate by 2007 to meet a 20 percent slack capacity planning criteria for Northern California needs, especially for power plants.

3. Non-core natural gas storage capacity and usage appears inadequate to fully mitigate temporary and seasonal supply shortfalls and temporary market price spikes for EG demand.

4. The energy sector may not be able to acquire all the financing it needs for critical infrastructure investments.

Infrastructure Questions

a) Should the State support a greater level of instate natural gas storage capacity and use it as more cost-effective means than additional pipelines to ensure supply reliability and manage price volatility?

b) Should the State require a higher level of border pipeline "slack capacity" as a more cost-effective means to ensure supply reliability and manage price differences between supply regions?

c) Does the State need a higher level of intrastate pipeline transfer capacity to provide it greater flexibility to absorb regional price/supply shocks and take advantage of regional price differences?

d) Should the State request FERC to require a higher level of interstate pipeline and/or storage capacity along the major interstate pipeline corridors to ensure all available natural gas supplies can physically reach California's border during times of peak demand?

e) Should the State consider regulatory and/or operational design changes to the instate pipeline system in order to fully accommodate the changes in demand being caused by the greater use of natural gas in peaking and baseload thermal power plants?

f) Should the government authorize construction of enough infrastructure to ensure there is never a supply shortfall or are ratepayers willing to accept a minimal level of risk of shortfalls to avoid higher costs?

g) Does the government (federal/state/local) permitting process operate effectively to ensure needed facilities can receive permits in a timely manner?

D. Price/Market Issues

1. Natural gas market prices are more volatile than desired.

2. The number of credit-worthy gas market participants is contracting and may be below that needed for a fully liquid and robust market that can deliver accurate market prices.

Price/Market Questions:

a) Should the State encourage/require a greater use of natural gas portfolio purchasing that blends daily market purchases with long-term market commitments, contracts, and physical purchases?

Conclusions

The Energy Commission staff's modeling, analysis, and observations of the natural gas markets leads it to believe that additional work is needed to clarify many significant issues. The three key issues are:

1. Risk analysis affecting both short-term and long-term conditions,
2. Access to new supplies, including LNG, and
3. Natural gas storage role.

First, the Energy Commission staff proposes to conduct additional analysis of the potential risks and uncertainties that California natural gas consumers face. Staff have identified risk issues that affect both short-term and long-term market conditions. The scenario analysis conducted for this report helped highlight the need for additional work and should also help focus the future work on key issues.

Second, the Energy Commission staff proposes to continue its investigation into potential new supplies that might benefit the U.S. and California, including the benefits and costs that LNG projects might bring to California consumers. This investigation must not only examine the energy benefits, but also review the public health and safety risks, the potential environmental impacts, and the permitting/regulatory environment of LNG.

Third, the Energy Commission staff proposes to examine the potential role that natural gas storage facilities can play in not only meeting seasonal peak day demands, but also in mitigating market price spikes. This examination needs to also review the potential usage of natural gas facilities by both core and non-core customers.

ACRONYMS

Bcf — Billions of cubic feet
Btu — British thermal unit
CERI — Canadian Energy Research Institute
CFE — *Comision Federal de Electricidad*
CPUC — California Public Utilities Commission
EPN-TRW — El Paso North – Transwestern pipeline corridor
EPS — El Paso Southern pipeline system corridor
FERC — Federal Energy Regulatory Commission
GRI — Gas Research Institute
GTI — Gas Technology Institute
GTN — (PG&E) Gas Transmission Northwest
GWh — Gigawatt-hours
IERP — Integrated Energy Policy Report
IOU — Investor Owned Utility
IPSO — Integrated Price and Supply Outlook
LNG — Liquefied natural gas
Mcf — Thousand Cubic Feet
MMcf — Million cubic feet
MMcfd - Million cubic feet per day
MW — Megawatt or megawatts
NARG — North American Regional Gas model
PG&E — Pacific Gas and Electric Company
PURPA — Public Utility Regulatory Policy Act
SCG L 300 — Delivery from PG&E's Line 300 to the SoCal Gas service area at Wheeler Ridge.
SCG L 401 — **N**atural gas carried on PG&E's Line 401 for delivery either directly or by displacement to SoCal Gas at Wheeler Ridge.
SDG&E — San Diego Gas and Electric Company
SJ-Xover — San Juan Crossover pipeline
SoCal Gas — Southern California Gas Company
Tcf — Trillion cubic feet
Tcf/yr — Trillion cubic feet per year
TEOR — Thermally enhanced oil recovery
WECC — Western Electricity Coordinating Council

GLOSSARY

Capacity Factor — *See pipeline capacity factor.*

Cogeneration — The production of electrical energy and another form of useful energy (such as heat or steam) through the sequential use of energy.

Combined Cycle Power Plant — An electricity generating station that uses waste heat from its gas turbines to produce steam for conventional steam turbines.

Commodity Cost — The cost of just the natural gas product, itself.

Core customer (gas utility definition) — A customer who depends on the local distribution company for gas supply and all associated services. Core customers include all residential, regardless of load size, commercial customers with annual loads below 250,000 therms per year (annual monthly average usage level of 20,800 therms), and those commercial customers with annual loads above 250,000 therms electing to receive core service. In the event of a shortage, the gas utility may curtail deliveries to noncore customers, but will not curtail deliveries to its core customers except in extreme conditions.

Core customer (NARG definition) — One of three end-use customer classes within each demand region. Core customers rely solely on natural gas; they can not switch to an alternative fuel.

Cubic Feet — The most common unit of measure of gas volume. One cubic foot roughly equals 1,000 Btu's.

Fuel Cell — An electrochemical engine (no moving parts) that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly to electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes.

Inelastic Demand for Energy — Demand does not increase or decrease despite changes in prices. Demand can be met by natural gas or by an alternative fuel.

Interstate Pipeline — A federally regulated company engaged in the business of transporting natural gas across state lines from producing regions to end-use markets.

Merchant Generator — Any generating unit not owned by a traditional load-servicing utility.

Noncore Customer (gas utility definition) — A customer who must make commercial arrangements with a gas service provider, other than the local distribution company, for gas supply and distribution services. Noncore customers include all cogeneration, regardless of load size, and those commercial, industrial, and electricity-generation customers with annual loads above 250,000 therms (annual monthly average usage level of 20,800 therms).

Noncore Customer (NARG definition) — One of three end-use customer classes in a demand region that can switch from natural gas to an alternate fuel once the price of natural gas exceeds a pre-determined cost. Power generation is not included in the noncore customer class.

Pipeline Capacity — A measure of the maximum amount of natural gas that can flow through a pipeline based on the pipeline's maximum allowable design pressure.

Pipeline Capacity Factor — The ratio of the amount of pipeline capacity used during average operations compared to its maximum capacity rating (expressed as a percent).

Potential Resources – Refers to an estimate of the remaining natural gas in a specified area which has not yet been discovered but which is judged to be recoverable.

Proved Reserves — Natural gas resources which have been discovered and which can be extracted economically with current technology.

Proved Reserve Revisions — Changes in the estimates of proved reserves resulting from advances in recovery techniques or technologies, but not from extensions of known gas fields.

Reserve Appreciation Factor — A parameter used in NARG to take into account proved reserve revisions.

Reserves — The portion of discovered natural gas resources, which has not already been produced. Includes both proved reserves and other reserves. There is the same as the Proved Reserves definition. We have no definition for "other reserves" and I don't know what it would be.

Resource Base — An estimate of the amount of natural gas available, based on the combination of proved resources and those additional volumes that have not yet been discovered, but are estimated to be 'discoverable' given current technology and economics.

Sensitivity Analysis — Investigation into how projected performance varies along with changes in the key assumptions on which the projections are based.

Spot Market — A method of contract purchasing whereby commitments by the buyer and seller are of a short duration at a single volume price. The duration of these contracts is typically one day, otherwise, the contract is for less than a month, and the complexity of the contracts is significantly less than their traditional market counterparts.

Therm — A unit denoting the heating value of natural gas. Equal to 100,000 Btus. Ten therms is a decatherm, which roughly equals 1,000 cubic feet of natural gas or one million Btus.

WECC — The Western Electricity Coordinating Council was formed on April 18, 2002, by the merger of the Western Systems Coordinating Council and the two regional transmission associations in western North America. It is one of the ten electric reliability councils in North America, encompassing a geographic area equivalent to over half the United States. The members, representing all segments of the electricity industry, provide electricity to 71 million people in the following 14 Western states, two Canadian provinces, and portions of one Mexican State, respectively: Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming; Alberta and British Columbia; and Baja California.

Wellhead — The assembly of fittings, valves, and controls located at the surface and connected to the flow lines, tubing, and casing of the well so as to control the flow from the reservoir. (Delete the rest of this.) The point at which a well (whether or not cased) reaches the surface of the land.

Wellhead Price – As used in this report, the natural gas price at the point it is ready for sale. Normally this would be at the point the natural gas enters an interstate pipeline. At this point all cost associated with production, gathering, conditioning, and initial compression have been accounted for.

ENDNOTES

i Natural Gas: Meeting the Challenges of the Nations Growing Natural Gas Demand, Vol. II, National Petroleum Council, December 1999.

ii Natural Gas Intelligence, Intelligence Press, NEB Report Outlines Canadian Supply/Demand Scenarios, January 13, 2003.

iii Natural Gas: Meeting the Challenges of the Nations Growing Natural Gas Demand, Vol. I, Summary report, National Petroleum Council, December 1999.

[iv] DOI et al, Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to Their Developments*,* January 2003.

v Environmental Science and Technology, Design of Natural Gas Pipeline Questioned, October 2001.

vi Karpowicz, Cheryl, Environmental Regulatory Issues and Opportunities for West Coast LNG Terminals, February 2003.

vii The WECC region includes nine Western states, portions of Montana, South Dakota, New Mexico, and Texas, Northern Baja California in Mexico, and British Columbia and Alberta in Canada.

[viii] Refer to Electricity Infrastructure Assessment, Electricity Analysis Office, California Energy Commission, Pub# 100-03-007F, May 27, 2003.

APPENDIX A

Natural Gas Resource Cost Curves

Table A-1
Natural Gas Resource Cost Curve Definitions
Conventional Resources

Basin	USGS of MMS Province	Description
Anadarko	USGS 53 and 59 USGS 55-56 USGS 58 USGS 60-62	Central Kansas Nehama Uplift Anadarko Basin Arkoma Basin
Appalachian	USGS 67 USGS 68-69	Appalachian Basin Blue Ridge Thurst Belt/Piedmont
California	USGS 7-9 USGS 10-14 Onshore USGS 10-14 Onshore MMS Offshore	Northern California Onshore Southern California Onshore Southern California State Offshore Federal Offshore
Gulf Coast	USGS 47 Onshore USGS 47 Offshore USGS 48-50 Onshore USGS 48-50 Offshore USGS 65 USGS 84 USGS 85 MMS Offshore	Western Gulf Onshore Western Gulf State Offshore Eastern Gulf Onshore Eastern Gulf State Offshore Black Warrior Basin Western Gulf Onshore-High H2S Content Eastern Gulf Onshore-High H2S Content Federal Offshore
North Central	USGS 63 USGS 64 and 66	Michigan Basin Illinois Basin & Cincinnati Arch
Northern Great Plains	USGS 27-29 USGS 31 and 51 USGS 33-34 USGS 35	Centeral/Southwestern Montana Williston Basin Powder River Basin Wind River Basin
Permian	USGS 44 and 46 USGS 45	Permain Basin and Marathon Thrust Belt Fort Worth Basin
Pacific Nortwest	USGS 4-5	Oregon-Washington
Rocky Mountains	USGS 17-19 USGS 20 USGS 21 USGS 36 USGS 37 USGS 38-39 USGS 81 USGS 83	Great Basin Uinta-Piceance Basin Paradox Basin Wyoming Thrust Belt Southwestern Wyoming Denver Basin Paradox Basin-High H2S Content Southwestern Wyoming-High H2S Content
San Juan	USGS 22-23 USGS 24-25 USGS 40-41	San Juan Basin Arizona-New Mexico Raton Basin

Table A-2
Natural Gas Resource Cost Curve Definitions
Coalbed Methane

Basin	Plays	Description
Anadarko	USGS 5650 USGS 6050 USGS 6250-6251	Forest City- Central Basin Cherokee Platform-Central Basin Arkoma Basin
Appalachian	USGS 6750-51 USGS 6752 USGS 6753	Northern Appalachian Central Appalachian Cahaba Field
Gulf Coast	6550-6553	Black Warrior Basin
North Central	USGS 6450	Illinois-Central Basin
Northern Great Plains	USGS 3350-3351 USGS 3550	Powder River Basin Wind River Basin
Pacific Northwest	USGS 450-452	Western Oregon-Washington
Rocky Mountains	USGS 2050-2052 USGS 2053-2056 USGS 3750-3755	Uinta Basin Piceance Basin Southwestern Wyoming
San Juan	USGS 2250 USGS 2252-2253 USGS 4150-4152	San Juan Overpressured San Juan Underpressured Raton Basin

Table A-3
Natural Gas Resource Cost Curve Definitions
Tight Gas

Basin	Plays	Description
Appalachian	USGS 6728-6730	Clinton-Medina
Gulf Coast	USGS 4923	Cotton Valley
Northern Great Plains	USGS 2810-2812 USGS 3113	North Central Montana-Biogenic Williston Basin
Rocky Mountains	USGS 2007 USGS 2010 USGS 2015-2020 USGS 3740-3744 USGS 3906	Piceance Basin - Mesaverde Williams Fork Piceance Basin - Mesaverde Iles Uinta Basin Greater Green River Basin Denver Basin
San Juan	USGS 2205 USGS 2209 USGS 2211	Dakota Central Basin Central Basin Mesaverde Pictured Cliffs

Table A-4
Natural Gas Resource Cost Curve Definitions
Shale

Basin	USGS of MMS Province	Description
Appalachian	USGS 6733-6735 USGS 6740-6741 USGS 6742	Upper Devonian Sandstone Devonian Shale Devonian Shale - Lower Maturity
North Central	USGS 6319-6320 USGS 6407 USGS 6604	Michigan Basin New Albany Cincinnati Arch - Devonian Black Shale
Permian	USGS 4503	Barnett Shale (Fort Worth Basin)

Table A-5
Natural Gas Resource Cost Curve Definitions
Canadian Cost Curves

Basin	CEC Designation	Description
Alberta	A B C D	Alberta Foothills Region South Central Region Frontier Region Coalbed Methane
British Columbia	A B C	Conventional Sources Coalbed Methane Sources South Territories
Eastern Canada	Offshore	Sable Island Offshore
Northern Canada	Onshore Offshore	Conventional Sources Conventional Sources
Saskatchewan	A	Conventional Sources

Table A-6a
Resource Cost Curves
Conventional

Anadarko USGS 53 & 59-Central Kansas Proved Reserves 0.00 TFC R/P Ratio 9.2 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.156	0.717
0.15	0.26	0.893
0.417	0.623	1.495
0.533	2.077	1.506
0.555	2.596	2.077
0.578	3.115	2.596
0		

Anadarko USGS 55 to 56-Nehama Uplift Proved Reserves 0.00 TFC R/P Ratio 9.2 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.114	0.571
0.182	0.249	0.893
0.29	0.384	1.132
0.395	1.402	1.828
0.434	3.583	3.074

Anadarko USGS 58 Anadarko Basin Proved Reserves 24.105 TFC R/P Ratio 9.4 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.062	0.405
2.823	0.135	0.55
5.067	0.177	0.633
7.23	0.26	0.872
9.509	0.395	1.049
11.223	0.893	1.433
12.375	1.755	2.368
13.478	4.071	3.167

Anadarko USGS 60 to 62-Arkoma Basin Proved Reserves 3.872 TCF R/P Ratio 7.9 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.062	0.405
0.586	0.104	0.602
1.634	0.177	0.644
2.127	0.218	0.883
2.584	0.343	1.059
3.023	0.571	1.236
3.278	1.028	1.817
3.501	2.015	2.887
3.637	3.126	3.313

Table A-6b
Resource Cost Curves
Conventional

Appalachian USGS 67 - Appalachian Basin Proved Reserves 0.236 TCF R/P Ratio 34.5 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.062	0.374
0.332	0.145	0.592
1.248	0.26	1.018
1.726	0.561	1.495
1.89	1.173	2.202
1.974	2.42	3.219

Appalachian USGS 68 to 69-Blue Ridge Thrust Belt Proved Reserves 0.00 TCF R/P Ratio 34.5 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.062	0.374
0.222	0.145	0.582
0.337	0.239	0.997
0.405	0.966	1.817
0.411	1.454	2.378
0.415	2.461	3.167

A-6c
Resource Table Cost Curves
Conventional

California UGSG 7 to 9-Northern CA Onshore Proved Reserves 0.498 TCF R/P Ratio 5.9 years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.073	0.519
0.112	0.093	0.571
0.418	0.166	0.748
1.185	0.218	0.841
1.756	0.28	0.945
2.595	0.395	1.142
3.044	0.633	1.423
3.436	1.018	1.88
3.631	1.173	1.942
3.86	1.682	1.973
4.045	3.842	2.056
4.102	5.982	2.814

California UGSG 10 to 14-So.CA Onshore Proved Reserves 2.126 TCF R/P Ratio 11.4 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.083	0.54
0.038	0.104	0.592
0.103	0.145	0.654
0.347	0.218	0.841
0.64	0.312	1.028
1.019	0.53	1.34
1.41	1.173	2.108
1.509	1.828	2.627
1.579	2.804	3.365
1.623	3.157	3.624

California UGSG 10 to 14-So.CA Offshore State Waters Proved Reserves 0.266 TCF R/P Ratio 34.5 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.228	0.665
0.295	0.384	0.665
0.853	0.862	1.246
0.91	0.924	1.308
0.992	0.987	1.433
1.147	2.17	1.963
1.295	4.33	2.7

California MMS Offshore So. California Federal Waters Proved Reserves 1.471 TCF R/P Ratio 28.6 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.228	0.665
2.231	0.384	0.665
6.456	0.862	1.246
6.888	0.924	1.308
7.504	0.987	1.433
8.676	2.17	1.963
9.8	4.33	2.7

A-6c (Continued)
Resource Table Cost Curves
Conventional

California Elk Hills Resource Basin Proved Reserves 0.75 Tcf R/P ratio 11.3 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.083	0.54
0.05	0.104	0.592
0.134	0.145	0.654
0.449	0.218	0.841
0.829	0.312	1.028
1.318	0.53	1.34
1.825	1.173	2.108
1.953	1.828	2.627
2.044	2.804	3.365
2.1	3.157	3.624

Table A-6d
Resource Cost Curves
Conventional

Gulf Coast USGS 47 - Western Gulf Onshore Proved Reserves 17.542 TCF R/P Ratio 5.7 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.021	0.353
8.862	0.073	0.447
19.97	0.156	0.582
43.081	0.467	0.602
46.935	0.675	0.717
50.222	1.111	0.8
53.422	1.994	0.841
54.647	3.012	0.945
55.829	5.556	1.35
56.552	9.606	2.773

Gulf Coast USGS 47 - Western Gulf Offshore Proved Reserves 0.335 TCF R/P Ratio 4.6 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.187	0.467
0.618	0.312	0.55
2.714	0.55	1.049
4.749	0.955	1.101
5.777	1.277	1.215
6.643	2.17	1.952
6.962	3.531	2.71
7.305	6.366	4.133

Gulf Coast USGS 48 to 50 -Eastern Gulf Onshore Proved Reserves 8.778 TCF R/P Ratio 9.9 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.021	0.426
5.19	0.166	0.447
9.721	0.322	0.561
13.205	0.685	0.779
14.527	1.122	0.852
15.578	1.682	1.101
17.971	4.767	2.004

Gulf Coast USGS 48 to 50 -Eastern Gulf Offshore State Waters Proved Reserves 0.917 TFC R/P Ratio 6.4 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.312	1.028
0.182	0.727	1.08
0.488	0.987	1.194
0.586	1.61	1.911
0.653	2.773	4.019

Table A-6d (Continued)
Resource Cost Curves
Conventional

Gulf Coast USGS 65 -Black Warrior Basin Proved Reserves 1.732 TCF R/P Ratio 13.5 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.135	0.592
0.392	0.218	0.727
0.846	0.374	0.966
1.271	0.737	1.443
1.829	3.001	1.63
1.944	3.915	3.458

Gulf Coast USGS 84- Western Gulf Onshore High Sulfur Content Proved Reserves 0.00 TCF R/P Ratio 5.7 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.197	0.415
0.559	0.55	0.602
0.838	0.8	0.706
1.175	1.921	0.997
1.266	3.417	1.059
1.367	5.192	3.583

Gulf Coast USGS 85 - Eastern Gulf Onshore High Sulfur Content Proved Reserves 0.00 TCF R/P Ratio 9.9 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.052	0.384
0.508	0.166	0.55
1.649	0.312	0.737
2.946	0.665	1.132
3.645	1.07	1.516
3.821	1.63	1.89
4.56	4.424	3.25

Gulf Coast Federal Waters Proved Reserves 26.044 TCF R/P Ratio 4 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.187	0.467
30.091	0.312	0.55
40.559	0.55	1.049
62.212	0.955	1.101
75.677	1.277	1.215
87.028	2.17	1.952
91.203	3.531	2.71
95.7	6.366	4.133

Table A-6e
Resource Cost Curves
Conventional

North Central USGS 63 - Michigan Basin Proved Reserves 0.993 TCF R/P Ratio 16.9 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.073	0.665
0.253	0.104	0.789
0.734	0.177	1.049
1.815	0.332	1.454
2.119	0.582	1.848
2.506	1.329	2.773
2.762	5.982	3.084

North Central USGS 64 & 66 - Illinois Basin Proved Reserves 0.00 TCF R/P Ratio 16.9 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.052	0.592
0.078	0.083	0.675
0.204	0.145	1.028
0.339	0.312	1.381
0.389	0.55	1.869
0.423	1.049	2.077
0.436	1.61	2.638
0.465	2.7	3.541

Table A-6f
Resource Cost Curves
Conventional

Northern Great Plains USGS 27 to 29 - Cenral/SW Montana Proved Reserves 0.278 TCF R/P Ratio 13.7 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.062	0.322
0.657	0.093	0.415
1.167	0.156	0.498
1.64	0.26	0.779
2.159	0.343	0.987
2.594	0.53	1.038
2.854	0.935	1.537
3.022	1.859	2.326
3.092	3.489	3.396

Northern Great Plains USGS 31 & 51 - Williston Basin Proved Reserves 0.373 TCF R/P Ratio 13.7 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.052	0.374
0.384	0.384	0.561
0.752	0.748	0.696
1.086	1.184	0.883
1.442	3.095	1.402
1.695	4.881	1.817

Northern Great Plains USGS 33 to 34 - Powder River Basin Proved Reserves 0.659 TCF R/P Ratio 14 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.177	0.758
0.534	0.291	0.831
1.05	0.55	1.08
1.683	2.015	1.163
1.79	3.063	1.485
1.899	4.891	1.983

Northern Great Plains USGS 35 Wind River Basin Proved Reserves 0.839 TCF R/P Ratio 14.1 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.114	0.509
0.141	0.249	0.779
0.277	0.436	1.101
0.399	0.665	1.257
0.453	1.713	2.285
0.491	3.396	3.292

Table A-6g
Resource Cost Curves
Conventional

Permian USGS 44 & 46 - Permian Basin Proved Reserves 14.343 TCF R/P Ratio 8 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.031	0.353
1.608	0.093	0.436
4.278	0.156	0.509
7.746	0.218	0.623
9.783	0.301	0.768
11.662	0.498	1.018
13.989	1.651	1.038
14.5	2.523	1.35
14.882	4.05	1.817
15.23	4.985	1.828

Permian USGS 45 - Fort Worth Basin Proved Reserves 0.00 TCF R/P Ratio 8 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.104	0.54
0.248	0.145	0.633
0.741	0.187	0.717
1.386	0.249	0.82
1.559	0.623	1.412
1.887	1.381	2.222
1.922	2.43	3.022

Table A-6h
Resource Cost Curves
Conventional

Pacific Northwest USGS 4 to 5 - Oregon/Washington Proved Reserves 0.028 TCF R/P Ratio 8.8 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.104	5.504
0.038	0.135	6.127
0.195	0.26	8.827
0.422	0.384	11.527
0.687	0.862	15.992
0.736	1.173	17.862
0.903	4.476	20.458
1.14	7.975	28.662

Table A-6i
Resource Cost Curves
Conventional

Rocky Mountains USGS 17 to 19 - Great Basin Proved Reserves 0.00 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.093	0.447
0.099	0.28	1.049
0.206	0.685	1.371
0.254	1.443	2.056
0.291	2.222	2.669
0.308	3.593	3.52
0.332	3.832	3.562

Rocky Mountains USGS 20 - Uinta/Piceance Basin Proved Reserves 0.543 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.135	0.748
1.715	0.28	1.018
2.574	0.395	1.205
2.888	0.509	1.298
3.22	0.675	1.641
3.7	1.122	1.963
3.924	1.703	2.357
3.996	3.448	2.388

Rocky Mountains USGS 21 - Paradox Basin Proved Reserves 0.336 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.104	0.623
0.22	0.187	0.779
0.589	0.312	1.028
0.949	0.613	1.392
1.222	1.194	2.025
1.329	1.828	2.555
1.472	3.063	3.417

Rocky Mountains USGS 36 - Wyoming Thrust Belt Proved Reserves 1.191 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.114	0.53
3.415	0.187	0.623
7.015	0.312	0.8
8.567	0.53	1.059
9.065	0.706	1.288
9.704	2.617	1.35
9.815	3.884	1.693
10.015	6.013	2.191

Table A-6i (Continued)
Resource Cost Curves
Conventional

Rocky Mountains USGS 37 Southwestern Wyoming Proved Reserves 2.805 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.114	0.613
0.071	0.156	0.789
0.236	0.249	0.883
0.3	0.322	1.018
0.468	0.644	1.371
0.526	0.893	1.641
0.582	1.277	2.035
0.629	1.942	2.617
0.708	3.323	3.458

Rocky Mountains USGS 38 to 39 - Denver Basin Proved Reserves 0.022 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.052	0.737
0.369	0.104	1.101
0.577	0.228	1.454
0.627	0.395	2.077
0.672	0.883	2.669
0.703	1.298	3.552

Rocky Mountains USGS 81 - Paradox Basin Proved Reserves 0.00 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.197	0.696
0.055	0.312	0.903
0.091	0.415	1.018
0.152	0.81	1.568
0.183	1.038	1.776
0.254	3.115	1.983
0.262	5.41	2.077
0.27	8.391	2.669

Rocky Mountains USGS 83 - Southwestern Wyoming High Sulfur Content Proved Reserves 0.00 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.166	0.613
0.147	0.26	0.768
0.244	0.322	0.872
0.358	0.426	1.028
0.48	0.727	1.464
0.562	1.09	1.672
0.643	2.17	2.523
0.753	3.313	3.282

Table A-6j
Resource Cost Curves
Conventional

San Juan USGS 22 to 23 - San Juan Basin Proved Reserves 3.15 TCF R/P Ratio 34.5 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.145	0.28
0.205	0.27	0.55
0.52	0.353	0.675
0.796	0.654	1.038
0.975	1.018	1.236
1.078	1.651	2.025
1.131	3.437	2.793
1.179	6.283	3.884

San Juan USGS 24 to 25 - Arizona/New Mexico Proved Reserves 0.00 TCF R/P Ratio 34.5 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.104	0.374
0.053	0.145	0.436
0.163	0.228	0.592
0.223	0.301	0.727
0.256	0.405	0.872
0.286	0.831	1.319
0.292	1.173	1.63
0.302	1.755	2.17
0.321	5.068	3.957

San Juan USGS 40 to 41 - Raton Basin Proved Reserves 0.00 TCF R/P Ratio 34.5 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.114	0.55
0.044	0.145	0.571
0.386	0.218	0.768
0.51	0.478	1.153
0.535	1.225	2.056
0.54	2.337	3.012

Table A-7a
Resource Cost Curves
Coalbed Methane

Anadarko USGS 5650 - Forest City (Central Basin) Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	1.225	0.737	0.1	0
0.197	1.495	0.945	0.1	1
0.3	2.368	1.599	0.1	2
0.375	3.115	2.274	0.093	3
0.443	6.231	3.624	0.082	4
			0.071	5
			0.036	10
			0.021	15
			0.014	20
			0.01	24

Anadarko USGS 6050 - cherokee Platform (Central Basin) Proved Reserves 0.07 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.457	0.519	0.063	0
0.636	0.571	0.613	0.063	1
1.1	0.976	0.924	0.063	2
1.4	1.745	1.516	0.063	3
1.6	3.25	2.69	0.063	4
1.89	6.231	4.497	0.063	5
			0.048	10
			0.034	15
			0.026	20
			0.021	24

Table A-7a (Continued)
Resource Cost Curves
Coalbed Methane

Anadarko USGS 6250 to 6251 - Arkoma Basin Proved Reserves 0.04 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.27	0.623	0.097	0
0.275	0.374	0.852	0.07	1
1.18	0.644	1.423	0.065	2
2.133	1.225	2.482	0.061	3
2.675	3.541	3.925	0.057	4
			0.053	5
			0.039	10
			0.029	15
			0.023	20
			0.02	24

Table A-7b
Resource Cost Curves
Coalbed Methane

Appalachian USGS 6752 - Central Appalachia Proved Reserves 0.81 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.27	0.353	0.196	0
0.549	0.353	0.426	0.143	1
1.777	0.53	0.633	0.098	2
2.19	2.077	1.059	0.074	3
2.309	4.019	2.575	0.059	4
			0.049	5
			0.026	10
			0.017	15
			0.013	20
			0.01	24

Appalachian USGS 6753 - Cahaba Field Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.55	0.363	0.045	0
0.133	0.737	0.509	0.045	1
0.179	1.132	0.82	0.045	2
0.249	1.911	1.423	0.045	3
0.274	3.437	2.596	0.045	4
0.29	6.407	4.455	0.045	5
			0.045	6
			0.049	7
			0.049	9
			0.048	10
			0.041	15
			0.034	20
			0.03	24

Table A-7b (Continued)
Resource Cost Curves
Coalbed Methane

Appalachian USGS 6750 to 6751 - Northern Appalachia Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.312	0.633	0.071	0
1.643	0.436	0.997	0.071	1
8.686	0.997	1.08	0.071	2
10.831	1.848	1.942	0.071	3
11.71	3.936	5.026	0.071	4
			0.067	5
			0.044	10
			0.02	20
			0.016	24

Gulf Coast USGS 6550- 6553 - Black Warrior Basin Proved Reserve 1.237 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.457	0.582	0.098	0
0.09	0.561	0.706	0.098	1
1.276	0.862	0.737	0.098	2
2.015	1.495	1.464	0.098	3
2.226	3.406	2.669	0.082	4
2.308	6.2	3.655	0.069	5
			0.058	6
			0.05	7
			0.044	8
			0.038	9
			0.034	10
			0.021	15
			0.014	20
			0.011	24

Table A-7b (Continued)
Resource Cost Curves
Coalbed Methane

North Central USGS 6450 - Illinois - Central Basin Proved Reserve 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.779	1.059	0.096	0
0.8	1.205	1.495	0.096	1
1.2	2.222	2.451	0.096	2
1.611	6.231	5.421	0.092	3
			0.083	4
			0.072	5
			0.036	10
			0.015	20
			0.011	24

Northern Great Plains USGS 3350 to 3351 - Powder River Basin Proved Reserve 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.26	0.363	0.32	0
0.295	0.405	0.447	0.255	1
0.349	0.685	0.613	0.135	2
0.914	1.236	0.945	0.08	3
1.349	2.326	1.599	0.051	4
1.475	4.486	2.814	0.035	5
			0.009	10
			0.004	15
			0.002	20
			0.001	24

Table A-7b (Continued)
Resource Cost Curves
Coalbed Methane

Northern Great Plains USGS 3550 - Wind River Basin Proved Reserve 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.26	0.363	0.081	0
0.211	0.343	0.395	0.081	1
0.336	1.236	0.945	0.081	2
0.375	2.814	2.129	0.081	3
0.429	4.486	2.814	0.073	4
			0.065	5
			0.038	10
			0.025	15
			0.017	20
			0.013	24

Pacific Northwest USGS 450 to 452 - Western Oregon/ Washington Proved Reserve 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.488	3.635	0.061	0
0.203	0.54	3.946	0.061	1
0.463	1.277	5.919	0.061	2
0.489	1.475	9.346	0.06	3
0.59	2.202	10.385	0.06	4
0.675	3.905	16.719	0.05	5
0.698	5.722	27.208	0.04	10
			0.041	15
			0.04	20
			0.039	24

Table A-7b (Continued)
Resource Cost Curves
Coalbed Methane

Rocky Mountains USGS 2050 to 2052 - Uinta Basin Proved Reserve 0.24 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.208	0.478	0.061	0
1.724	0.353	0.53	0.061	1
3.442	0.644	0.727	0.061	2
3.509	0.748	0.862	0.061	3
3.72	1.07	0.945	0.061	4
4.353	1.537	1.329	0.061	5
4.794	2.71	2.264	0.06	6
4.908	5.338	4.102	0.058	7
			0.055	8
			0.052	9
			0.049	10
			0.043	12
			0.036	15
			0.028	20
			0.027	21
			0.026	22
			0.025	23
			0.023	24

Table A-7b (Continued)
Resource Cost Curves
Coalbed Methane

Rocky Mountains USGS 2053 to 2056 - Piceance Basin Proved Reserve 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.187	0.447	0.061	0
2.261	0.239	0.478	0.061	1
4.696	0.395	0.519	0.061	2
6.191	0.582	0.633	0.054	3
6.404	0.717	0.727	0.053	4
6.863	0.997	0.883	0.052	5
7.2	1.267	0.997	0.05	6
7.602	5.483	3.967	0.048	7
			0.046	8
			0.044	9
			0.042	10
			0.034	15
			0.029	20
			0.026	24

Rocky Mountains USGS 3750 to 3755 - Southwestern Wyoming Proved Reserve 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.166	0.436	0.048	0
0.272	0.208	0.457	0.048	1
0.744	0.27	0.509	0.048	2
1.576	0.519	0.602	0.048	3
1.738	0.582	0.675	0.048	4
2.223	0.758	0.82	0.048	5
2.997	1.329	0.976	0.044	14
3.376	2.202	1.277	0.034	15
3.676	2.814	2.181	0.024	17
3.839	5.442	3.977	0.02	20
			0.017	24

Table A-7b (Continued)
Resource Cost Curves
Coalbed Methane

San Juan USGS 2250 - San Juan Basin Overpressured Proved Reserve 3.91 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.062	0.218	0.079	0
7.056	0.301	0.363	0.079	1
8.541	0.571	0.54	0.079	2
11.141	1.122	0.872	0.079	3
12.997	2.181	1.516	0.079	4
15.292	4.289	2.793	0.079	5
			0.069	6
			0.062	7
			0.056	8
			0.052	9
			0.048	10
			0.035	15
			0.028	20
			0.024	24

San Juan USGS 2252 to 2253 - San Juan Basin Underpressured Proved Reserve 3.91 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.177	0.249	0.084	0
6.187	0.27	0.312	0.084	1
7.791	0.478	0.436	0.084	2
10.212	1.651	1.153	0.084	3
11.141	3.188	2.004	0.073	4
12.607	5.473	3.344	0.065	5
			0.038	10
			0.025	15
			0.017	20
			0.013	24

Table A-7b (Continued)
Resource Cost Curves
Coalbed Methane

San Juan USGS 4150 to 4152 - Raton Basin Proved Reserve 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.073	0.239	0.074	0
0.044	0.093	0.26	0.074	1
0.832	0.177	0.312	0.074	2
1.384	0.322	0.436	0.074	3
1.51	1.194	1.07	0.068	4
1.6	2.077	1.443	0.06	5
1.7	2.326	1.911	0.037	10
1.804	4.548	3.271	0.022	20
			0.019	24

Table A-7c
Resource Cost Curves
Tight Sands

Appalachia USGS 6728 to 6730 - Clinton/Medina Proved Reserves 4.58 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.54	1.205	0.209	0
1.326	0.737	1.308	0.159	1
3.556	0.924	1.433	0.124	2
7.402	1.205	1.558	0.098	3
14.229	1.983	1.838	0.079	4
20.987	3.738	2.596	0.064	5
27.145	4.507	3.084	0.053	6
			0.045	7
			0.038	8
			0.032	9
			0.028	10
			0.024	11
			0.021	12
			0.018	13

Gulf Coast USGS 4923 - Cotton Valley Proved Reserves 2.978 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.052	0.363	0.144	0
0.982	0.073	0.374	0.119	1
2.838	0.114	0.395	0.1	2
4	0.54	0.81	0.084	3
5.1	2.181	1.682	0.072	4
5.77	6.605	2.513	0.061	5
			0.03	6
			0.016	15
			0.009	20
			0.006	25
			0.005	27

Table A-7c (Continued)
Resource Cost Curves
Tight Sands

Northern Great Plains USGS 2810 to 2812 - North Central Montana Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.083	0.426	0.076	0
2.375	0.135	0.519	0.069	1
8.756	0.228	0.768	0.063	2
13.877	0.426	1.163	0.058	3
25.559	0.831	1.267	0.053	4
32.746	1.028	1.402	0.049	5
37.524	1.402	1.713	0.033	10
41.177	2.378	2.015	0.023	15
42.754	4.382	3.655	0.015	20
			0.009	30
			0.007	35
			0.005	44

Northern Great Plains USGS 3113 - Williston Basin Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	1.734	1.205	0.083	0
1.043	1.973	1.869	0.075	1
1.532	2.669	2.908	0.068	2
1.732	3.894	3.375	0.062	3
1.789	6.844	3.655	0.057	4
			0.053	5
			0.049	6
			0.045	7
			0.042	8
			0.039	9
			0.037	10
			0.027	15
			0.021	20
			0.016	26

Table A-7c (Continued)
Resource Cost Curves
Tight Sands

USGS 503 - Eastern Orgeon/Washington Proved Reserves				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	1.983	4.881	0.22	0
1.648	2.253	5.088	0.172	1
5.138	4.268	6.75	0.134	2
8.232	4.818	7.165	0.104	3
9.132	6.21	7.581	0.081	4
12.091	7.352	8.515	0.063	5
			0.049	6
			0.038	7
			0.03	8
			0.023	9
			0.018	10
			0.005	15
			0.004	16
			0.002	19

Table A-7c (Continued)
Resource Cost Curves
Tight Sands

Rocky Mountains USGS 2007 - Piceance Basin (Mesaverde Williams fork) Proved Reserves 0.994 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.633	0.758	0.22	0
1.287	0.758	0.82	0.171	1
3.7	1.184	0.883	0.133	2
4	2.025	1.205	0.104	3
4.3	3.78	1.682	0.081	4
4.774	7.197	2.077	0.063	5
			0.049	6
			0.038	7
			0.03	8
			0.023	9
			0.018	10
			0.014	11
			0.011	12
			0.009	13
			0.007	14
			0.005	15
			0.004	16
			0.003	17
			0.002	20

Table A-7c (Continued)
Resource Cost Curves
Tight Sands

Rocky Mountains USGS 2010 - Piceance Basin (Mesaverde Iles) Proved Reserves 0.994 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.685	0.737	0.22	0
1.131	0.81	0.8	0.171	1
3.845	1.257	0.914	0.133	2
4.1	2.139	1.205	0.104	3
4.4	3.946	1.682	0.081	4
4.722	7.519	3.687	0.063	5
			0.049	6
			0.038	7
			0.03	8
			0.023	9
			0.018	10
			0.014	11
			0.011	12
			0.009	13
			0.007	14
			0.005	15
			0.004	16
			0.003	17
			0.002	20

Table A-7c (Continued)
Resource Cost Curves
Tight Sands

Rocky Mountains USGS 2015 to 2020 - Uinta Basin Proved Reserves 0.434 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.083	0.509	0.12	0
0.246	0.114	0.582	0.106	1
0.291	0.135	0.602	0.093	2
0.607	0.187	0.633	0.082	3
0.965	0.218	0.789	0.072	4
1.506	0.374	0.831	0.064	5
2.022	0.623	1.09	0.056	6
2.228	0.82	1.122	0.05	7
2.847	1.184	1.153	0.044	8
2.92	1.215	1.319	0.039	9
3.298	1.651	1.817	0.03	11
3.505	1.859	1.817	0.018	15
5.05	2.845	1.817	0.01	20
5.92	5.047	3.333	0.005	25
6.803	7.643	3.448	0.002	34

Table A-7c (Continued)
Resource Cost Curves
Tight Sands

Rocky Mountains USGS 3740 to 3744 - Greater Green River Basin Proved Reserves 6.162 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.218	0.436	0.217	0
1.059	0.249	0.457	0.17	1
1.134	0.322	0.54	0.133	2
3.161	0.478	0.696	0.104	3
11.716	0.665	0.717	0.081	4
15.043	0.768	0.8	0.064	5
27.759	1.038	0.831	0.05	6
35.006	1.153	1.049	0.039	7
40.459	1.464	1.101	0.031	8
53.262	1.713	1.163	0.024	9
74.129	2.555	1.194	0.019	10
91.876	3.115	1.516	0.015	11
99.912	4.206	1.745	0.011	12
107.616	5.597	1.963	0.009	13
117.14	8.817	2.918	0.007	14
			0.006	15
			0.004	16
			0.003	18
			0.002	20

Table A-7c (Continued)
Resource Cost Curves
Tight Sands

Rocky Mountains USGS 3906 - Denver Basin Proved Reserves 2.301 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.291	1.07	0.123	0
0.512	0.415	1.568	0.103	1
0.726	0.706	2.44	0.087	2
0.796	1.288	3.084	0.075	3
0.815	5.047	6.21	0.064	5
			0.033	10
			0.019	15
			0.008	25
			0.002	43

San Juan USGS 2205 - Dakota Central Basin Proved Reserves 2.105 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.28	0.312	0.091	0
4.838	0.395	0.447	0.083	1
6.8	0.592	0.717	0.075	2
7.576	1.848	1.848	0.069	3
8.281	6.812	3.24	0.057	5
			0.036	10
			0.014	20
			0.009	25
			0.005	30
			0.003	35
			0.002	40

Table A-7c (Continued)
Resource Cost Curves
Tight Sands

San Juan USGS 2209 - Central Basin Mesaverde Proved Reserves 4.592 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.073	0.208	0.074	0
3.016	0.26	0.228	0.069	1
4.511	0.519	0.26	0.064	2
6.858	1.038	0.332	0.059	3
8.287	1.558	0.498	0.051	5
9.16	2.077	1.267	0.035	10
9.327	3.126	2.461	0.016	20
			0.011	25
			0.008	30
			0.005	35
			0.004	49

San Juan USGS 2211 - Pictured Cliffs Proved Reserves 0.963 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.228	0.27	0.097	0
0.875	0.415	0.312	0.088	1
2.132	0.779	0.457	0.08	2
2.718	1.038	0.727	0.072	3
2.917	2.337	0.997	0.065	5
3.129	5.057	3.136	0.059	10
			0.023	20
			0.014	25
			0.009	30
			0.005	35

Table A-7d
Resource Cost Curves
Shale

USGS 6733 to 6735 - Upper Devonian Sandstone Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	1.007	1.765	0.407	0
2.74	1.537	2.067	0.211	1
5.172	2.492	2.15	0.125	2
7.373	3.967	2.658	0.082	3
10.378	6.096	2.7	0.057	4
12.781	7.975	2.856	0.041	5
			0.031	8

Appalachia USGS 6740 to 6741 - Devonian Shale Proved Reserves 1.38 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.145	0.613	0.052	0
0.88	0.197	0.727	0.049	1
3.981	0.218	0.883	0.046	2
6.293	0.571	1.952	0.043	3
7.748	1.599	2.326	0.04	4
8.9	2.409	3.853	0.038	5
9.785	4.694	5.93	0.029	10
			0.023	15
			0.019	20
			0.015	25
			0.013	30
			0.011	35
			0.01	40
			0.008	45
			0.008	49

Table A-7d (Continued)
Resource Cost Curves
Shale

Appalachia USGS 6742 - Devonian Shale (Lower Maturity) Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.737	1.641	0.097	0
1.69	1.059	2.887	0.085	1
2.716	2.046	3.614	0.075	2
3.31	5.41	5.525	0.066	3
			0.059	4
			0.054	5
			0.034	10
			0.024	15
			0.018	20
			0.014	25
			0.013	27

North Central USGS 6319 to 6320 - Michigan Basin (Antrim Shale) Proved Reserves 1.01 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.156	0.768	0.107	0
1.244	0.156	0.893	0.093	1
6.048	0.301	1.34	0.081	2
11.495	0.633	1.734	0.071	3
14.58	1.277	1.807	0.063	4
15.839	2.482	2.202	0.055	5
16.215	5.857	3.313	0.032	10
			0.02	15
			0.014	20
			0.01	25
			0.007	30
			0.006	34

Table A-7d (Continued)
Resource Cost Curves
Shale

North Central USGS 6407 - New Albany Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.903	1.215	0.082	0
0.408	1.049	1.776	0.075	1
0.904	1.765	2.295	0.069	2
1.392	2.305	4.112	0.063	3
1.772	6.947	6.397	0.058	4
			0.054	5
			0.038	10
			0.027	15
			0.021	20
			0.015	26

North Central USGS 6604 - Cincinnati Arch (Devonian Black Shale) Proved Reserves 0.00 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	1.61	1.049	0.081	0
0.301	1.724	1.485	0.074	1
0.626	2.004	2.523	0.068	2
1.033	2.658	3.489	0.062	3
1.254	3.863	3.998	0.057	4
1.306	6.314	5.088	0.053	5
			0.053	10
			0.037	15
			0.027	20
			0.016	25
			0.014	27

Table A-7d (Continued)
Resource Cost Curves
Shale

Permian USGS 4503 - Barnett Shale (Fort Worth Basin) Proved Reserves 0.12 TCF				
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)	Production Profile	Production Year
0	0.28	0.498	0.291	0
0.473	0.395	0.53	0.206	1
1.342	0.467	0.582	0.146	2
1.438	0.644	0.633	0.103	3
2.37	0.862	0.717	0.073	4
2.473	1.163	0.768	0.052	5
2.981	1.641	0.872	0.037	6
3.037	3.2	2	0.026	7
3.266	5.2	4	0.018	8
			0.013	9
			0.009	10
			0.007	11
			0.005	12
			0.003	13

Table A-7e
Resource Cost Curves
Canada

Alberta - A Foothills Conventional Proved Reserves 25.84 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.049	0.479
3.062	0.068	0.487
6.233	0.117	0.504
10.963	0.177	0.528
15.217	0.177	0.56
17.087	0.177	0.585
20.112	0.177	0.61
26.052	0.177	0.61
31.827	0.177	0.618
35.567	0.177	0.708
38.518	0.177	0.814
42.643	0.236	0.814
48.29	0.323	0.814
54.377	0.598	0.814
59.125	0.706	0.814
62.718	1.745	0.814
65.945	1.932	2.081
73.333	3.923	4.165

Alberta - B South Central Conventional Proved Reserves 23.0 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.039	0.369
1.558	0.088	0.369
4.125	0.088	0.369
9.772	0.088	0.385
12.467	0.127	0.41
14.74	0.127	0.443
19.873	0.127	0.45
22.495	0.157	0.467
24.31	0.157	0.467
29.59	0.226	0.467
31.295	0.245	0.467
33.11	0.255	0.516
35.072	0.432	0.524
37.693	0.471	0.541
41.433	0.52	0.614
46.933	1.442	1.521
49.5	2.452	2.094
56.833	4.374	4.186

Table A-7e (Continued)
Resource Cost Curves
Canada

Alberta - C Frontier Conventional Proved Reserves 4.006 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.059	0.356
0.458	0.107	0.381
1.412	0.148	0.479
2.713	0.236	0.479
3.245	0.294	0.479
4.363	0.304	0.553
5.61	0.323	0.585
6.527	0.51	0.585
7.737	0.52	0.618
8.855	0.588	0.618
11.532	1.089	0.618
12.723	1.265	0.708
13.768	1.265	1.117
15.73	2.334	1.321
16.757	2.334	1.738
17.655	2.334	1.803
18.718	3.933	4.14
20.643	5.443	6.004
23.833	9.504	7.917

Alberta - D Coalbed Methane Proved Reserves 0.00 TCF R/P Ratio 20 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.185	0.315
2.369	0.185	0.391
13.965	0.239	0.423
14.968	0.315	0.423
22.662	0.434	0.488
27	0.814	0.64
31	1.086	0.706
34	2.714	0.836
38	4.342	1.335
41	6.513	4.342

Table A-7e (Continued)
Resource Cost Curves
Canada

British Columbia - A Conventional Proved Reserves 8.67 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.02	0.495
0.97	0.02	0.495
2.48	0.029	0.495
4.62	0.039	0.504
8.34	0.098	0.52
8.94	0.196	0.569
11.53	0.294	0.585
13.2	0.491	0.601
16.03	0.588	0.634
19.79	0.736	0.683
22.53	0.883	0.733
27.86	1.03	0.757
29.87	1.226	0.809
31.51	1.471	0.872
32.93	1.962	0.872
33.74	2.452	1.247
34.15	2.942	1.713
35	3.432	2.105
36	3.923	3.716

British Columbia - B Coalbed Methane Proved Reserves 2.0 TCF R/P Ratio 20 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	1.177	0.487
2	1.373	0.569
4	1.765	0.814
6	2.059	1.1
7	2.452	1.713
8	3.923	2.326
8.5	4.903	2.938
9	5.885	3.348

Table A-7e (Continued)
Resource Cost Curves
Canada

British Columbia - C South Territories Proved Reserves 0.00 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.536	0.268
0.139	0.536	0.268
0.223	0.581	0.268
0.667	0.625	0.286
0.742	0.67	0.357
0.868	0.804	0.357
1.302	1.34	0.402
1.551	2.233	0.447
2.074	2.456	0.536
2.21	2.769	0.625
2.39	3.126	0.67
2.608	3.796	0.804
2.706	4.376	0.893
2.936	5.181	1.072
3.155	5.806	1.563

Eastern Canada Sable Island (Offshore) Proved Reserves 5.0 TCF R/P Ratio 20 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.536	0.357
2.36	0.625	0.357
2.93	0.714	0.357
4	0.893	0.536
6	1.34	0.581
8.2	2.233	1.34
12.78	3.572	3.572

Northern Canada Offshore - Conventional Proved Reserves 0.00 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	1.373	62.308
8	1.52	62.308
15	1.991	62.308
20	4.903	62.308

Northern Canada Onshore - Conventional Proved Reserves 12.785 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.98	62.308
10	1.962	62.308
15	2.942	62.308
20	3.678	62.308
25	4.414	62.308
30	5.149	62.308
35	5.885	62.308
40	6.619	62.308

Table A-7e (Continued)
Resource Cost Curves
Canada

Saskatchewan - A Conventional Proved Reserves 3.079 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	0.02	0.402
0.3	0.02	0.402
0.69	0.245	0.466
1.03	0.637	0.67
1.55	0.98	0.874
1.76	1.471	1.283
2.08	2.207	1.691
2.23	2.942	2.1
2.8	3.923	2.509
3.8	5.885	2.918

Saskatchewan - B Conventional Proved Reserves 0.00 TCF R/P Ratio 10 Years		
Cumulative Reserves (TCF)	Capital Cost (00$/MCF)	Operating Cost (00$/MCF)
0	5.635	33.808
2	5.635	33.808
3	5.635	33.808

APPENDIX B

LNG Assumptions

LNG Assumptions

Capacity:

LNG Projects of 4 million tons annually

Capital Costs for Greenfield Projects:

Liquefaction	$292 million per ton of capacity
Regasification	$120 million per ton of capacity

Conversion Losses:

Field Production	10%
Liquefaction	9%
Shipping	0.15% per day
Regasification	2.5%

Credits:

Condensate based on $20.00/bbl crude oil

Shipping Cost:

Tanker Day rate of $70,000 per day
Tanker Speed 20 knots
Days in Port 4 days

Operating Costs:

Liquefaction	4.5% of capital costs
Regasification	2.8% of capital costs

Discounted Cash Flow:

DCF 15%

LNG Costs Used for NARG model

East Coast $4.18 - East Coast LNG cost is based on a calculated weighted cost from the LNG producing centers supplying LNG to the East Coast.

West Coast $4.11 - West Coast LNG cost is based on a calculated weighted cost from potential LNG producing centers that could supply LNG to the West Coast.

APPENDIX C

Natural Gas Demand Projections

Table C-1
Core Demand by NARG Region - TCF per Year

NARG Region	2003	2008	2013	2018	2023	2028	2033	2038
Lower 48								
East North Central	3.054	3.214	3.2944	3.3778	3.4664	3.554	3.6442	3.7358
East South Central	0.717	0.7726	0.812	0.8556	0.8906	0.9136	0.9366	0.9598
Middle Atlantic	1.7926	1.852	1.898	1.9474	1.995	2.0452	2.0966	2.1498
New England	0.425	0.4496	0.473	0.497	0.5156	0.5286	0.5416	0.5548
Pacific Northwest	0.3322	0.3588	0.3872	0.4134	0.4374	0.4492	0.4604	0.4722
Rocky Mountains	0.467	0.5126	0.5612	0.6096	0.6432	0.6596	0.61024	0.42576
South Atlantic	1.248	1.3744	1.506	1.6304	1.7206	1.764	1.809	1.8544
Southwest Desert	0.2154	0.2376	0.2612	0.286	0.3036	0.3114	0.3188	0.3274
West North Central	1.0566	1.131	1.171	1.2094	1.2412	1.2724	1.3046	1.3376
West South Central	2.3586	2.498	2.1322	0.7636	2.7558	2.8252	2.9046	3.002
California								
PG&E	0.2666	0.2792	0.2902	0.3012	0.3106	0.3134	0.3154	0.3174
SoCalGas	0.3554	0.377	0.3972	0.4182	0.4358	0.4398	0.4438	0.4478
SDG&E	0.0464	0.0528	0.0568	0.0606	0.0632	0.0642	0.0652	0.066
Non-Utility								
Northern California	0	0	0	0	0	0	0	0
Southern California	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032
EOR	0	0	0	0	0	0	0	0
Canada								
British Columbia	0.1772	0.183	0.1878	0.1918	0.196	0.201	0.2062	0.212
Eastern Canada	0.1754	0.1774	0.1804	0.1872	0.193	0.198	0.203	0.208
Ontario	0.7424	0.7512	0.7712	0.8062	0.8352	0.8564	0.8784	0.9006
Western Canada	0.6336	0.6602	0.6826	0.7096	0.7318	0.7506	0.769	0.789
Mexico								
Baja	0	0	0	0	0	0	0	0
North Central	0	0	0	0	0	0	0	0
North East	0	0	0	0	0	0	0	0
Total								
Lower 48 (No CA)	11.6664	12.4006	12.4962	11.5902	13.9694	14.3232	14.62664	14.81956
California	0.7004	0.741	0.7762	0.812	0.8416	0.8494	0.8564	0.8632
Canada	1.7286	1.7718	1.822	1.8948	1.956	2.006	2.0566	2.1096
Mexico	0	0	0	0	0	0	0	0

Table C-2
Noncore Demand by NARG Region - TCF per Year

NARG Region	2003	2008	2013	2018	2023	2028	2033	2038
Lower 48								
East North Central	0.703	0.783	0.821	0.8478	0.8632	0.8844	0.9066	0.9298
East South Central	0.279	0.298	0.313	0.3256	0.3298	0.3386	0.3468	0.3558
Middle Atlantic	0.4202	0.4476	0.4638	0.4904	0.5066	0.5196	0.5326	0.5458
New England	0.121	0.127	0.136	0.1412	0.1468	0.1508	0.1548	0.1588
Pacific Nortwest	0.084	0.0896	0.0964	0.099	0.1038	0.1074	0.1096	0.1124
Rocky Mountains	0.0688	0.0734	0.0794	0.0812	0.0826	0.0852	0.0866	0.0894
South Atlantic	0.4406	0.503	0.5628	0.6134	0.6302	0.6462	0.6624	0.6794
Southwest Desert	0.0454	0.0478	0.0514	0.0534	0.0554	0.0572	0.0582	0.0592
West North Central	0.2578	0.3032	0.3346	0.3624	0.3698	0.379	0.389	0.399
West South Central	1.6428	1.7596	1.8646	1.943	1.9688	2.0182	2.0694	2.1216
California								
PG&E	0.213	0.2232	0.2144	0.2064	0.1996	0.1978	0.1966	0.1946
SoCalGas	0.1624	0.1666	0.177	0.1778	0.181	0.181	0.1806	0.1792
SDG&E	0.0102	0.0116	0.014	0.0142	0.015	0.015	0.015	0.015
Non-Utility								
Northern California	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Southern California	0.032	0.032	0.032	0.032	0.032	0.032	0.032	0.032
EOR	0.2146	0.2182	0.2234	0.2254	0.2272	0.228	0.2282	0.229
Canada								
British Columbia	0.1854	0.1678	0.1558	0.1598	0.1638	0.1678	0.172	0.1768
Eastern Canada	0.1886	0.1696	0.2226	0.2798	0.3408	0.3498	0.3588	0.3678
Ontario	0.4016	0.4572	0.5912	0.7592	0.9046	0.9276	0.9508	0.9748
Western Canada	0.3528	0.4722	0.553	0.627	0.6704	0.6874	0.7046	0.7226
Mexico								
Baja	0	0	0	0	0	0	0	0
North	0.083	0.0878	0.092	0.093	0.081	0.081	0.081	0.081
East	0.0774	0.1404	0.1476	0.149	0.129	0.129	0.129	0.129
Total								
Lower 48 (No CA)	4.0626	4.4322	4.723	4.9574	5.057	5.1866	5.316	5.4512
California	0.6472	0.6666	0.6758	0.6708	0.6698	0.6688	0.6674	0.6648
Canada	1.1284	1.2668	1.5226	1.8258	2.0796	2.1326	2.1862	2.242
Mexico	0.1604	0.2282	0.2396	0.242	0.21	0.21	0.21	0.21

Table C-3
Power Generation Demand by NARG Region - TCF per Year

NARG Region	2003	2008	2013	2018	2023	2028	2033	2038
Lower 48								
East North Central	0.604	0.928	1.2534	1.4744	1.5116	1.5498	1.5898	1.3
East South Central	0.624	1.132	1.5376	1.6966	1.7398	1.784	1.8292	1.4928
Middle Atlantic	0.4798	0.6678	0.829	0.8896	0.9126	0.9356	0.9588	0.7824
New England	0.324	0.394	0.4524	0.4644	0.4764	0.4884	0.5006	0.4088
Pacific Nortwest	0.0968	0.106	0.1162	0.1264	0.1332	0.1392	0.1454	0.1208
Rocky Mountains	0.1976	0.2218	0.2308	0.2392	0.2454	0.2522	0.2584	0.2112
South Atlantic	0.8652	1.0602	1.2308	1.3086	1.3418	1.376	1.411	1.1512
Southwest Desert	0.4082	0.3916	0.406	0.426	0.4458	0.4652	0.4862	0.4024
West North Central	0.131	0.1892	0.2706	0.3064	0.3136	0.3216	0.3296	0.2688
West South Central	1.8208	2.074	2.2806	2.383	2.4432	2.5046	2.5678	2.0952
California								
PG&E	0.368	0.375	0.39	0.404	0.414	0.4242	0.4352	0.3552
SoCalGas	0.2986	0.3266	0.3348	0.343	0.348	0.353	0.3582	0.2904
SDG&E	0.0332	0.0342	0.0352	0.036	0.0362	0.0372	0.038	0.0304
Non-Utility								
Northern California	0	0	0	0	0	0	0	0
Southern California	0	0	0	0	0	0	0	0
EOR	0.2062	0.268	0.2728	0.2768	0.2808	0.285	0.2898	0.2344
Canada								
British Columbia	0	0	0	0	0	0	0	0
Eastern Canada	0	0	0	0	0	0	0	0
Ontario	0	0	0	0	0	0	0	0
Western Canada	0	0	0	0	0	0	0	0
Mexico								
Baja	0.1108	0.1302	0.1312	0.1324	0.1342	0.1352	0.1364	0.1104
North	0	0	0	0	0	0	0	0
East	0	0	0	0	0	0	0	0
Total								
Lower 48 (No CA)	5.5514	7.1646	8.6074	9.3146	9.5634	9.8166	10.0768	8.2336
California	0.906	1.0038	1.0328	1.0598	1.079	1.0994	1.1212	0.9104
Canada	0	0	0	0	0	0	0	0
Mexico	0.1108	0.1302	0.1312	0.1324	0.1342	0.1352	0.1364	0.1104

Table C-4
Total Demand by NARG Region - TCF per Year

NARG Region	2003	2008	2013	2018	2023	2028	2033	2038
Lower 48								
East North Central	4.361	4.925	5.3688	5.7	5.8412	5.9882	6.1406	5.9656
East South Central	1.62	2.2026	2.6626	2.8778	2.9602	3.0362	3.1126	2.8084
Middle Atlantic	2.6926	2.9674	3.1908	3.3274	3.4142	3.5004	3.588	3.478
New England	0.87	0.9706	1.0614	1.1026	1.1388	1.1678	1.197	1.1224
Pacific Nortwest	0.513	0.5544	0.5998	0.6388	0.6744	0.6958	0.7154	0.7054
Rocky Mountains	0.7334	0.8078	0.8714	0.93	0.9712	0.997	0.95524	0.72636
South Atlantic	2.5538	2.9376	3.2996	3.5524	3.6926	3.7862	3.8824	3.685
Southwest Desert	0.669	0.677	0.7186	0.7654	0.8048	0.8338	0.8632	0.789
West North Central	1.4454	1.6234	1.7762	1.8782	1.9246	1.973	2.0232	2.0054
West South Central	5.8222	6.3316	6.2774	5.0896	7.1678	7.348	7.5418	7.2188
California								
PG&E	0.8476	0.8774	0.8946	0.9116	0.9242	0.9354	0.9472	0.8672
SoCalGas	0.8164	0.8702	0.909	0.939	0.9648	0.9738	0.9826	0.9174
SDG&E	0.0898	0.0986	0.106	0.1108	0.1144	0.1164	0.1182	0.1114
Non-Utility								
Northern California	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Southern California	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064
EOR	0.4208	0.4862	0.4962	0.5022	0.508	0.513	0.518	0.4634
Canada								
British Columbia	0.3626	0.3508	0.3436	0.3516	0.3598	0.3688	0.3782	0.3888
Eastern Canada	0.364	0.347	0.403	0.467	0.5338	0.5478	0.5618	0.5758
Ontario	1.144	1.2084	1.3624	1.5654	1.7398	1.784	1.8292	1.8754
Western Canada	0.9864	1.1324	1.2356	1.3366	1.4022	1.438	1.4736	1.5116
Mexico								
Baja	0.1108	0.1302	0.1312	0.1324	0.1342	0.1352	0.1364	0.1104
North	0.083	0.0878	0.092	0.093	0.081	0.081	0.081	0.081
East	0.0774	0.1404	0.1476	0.149	0.129	0.129	0.129	0.129
Total								
Lower 48 (No CA)	21.2804	23.9974	25.8266	25.8622	28.5898	29.3264	30.01944	28.50436
California	2.2536	2.4114	2.4848	2.5426	2.5904	2.6176	2.645	2.4384
Canada	2.857	3.0386	3.3446	3.7206	4.0356	4.1386	4.2428	4.3516
Mexico	0.2712	0.3584	0.3708	0.3744	0.3442	0.3452	0.3464	0.3204

Table C-5
Statewide Natural Gas Demand Forecast
MMcf/d

Year	Residential	Commercial	Industrial*	Electricity Generation**
2003	1,383	550	2,532	1,492
2004	1,394	559	2,558	1,574
2005	1,405	567	2,602	1,802
2006	1,416	576	2,643	1,932
2007	1,429	580	2,641	1,960
2008	1,443	585	2,656	2,038
2009	1,458	589	2,658	2,149
2010	1,472	593	2,644	2,145
2011	1,486	597	2,680	2,220
2012	1,499	601	2,674	2,242
2013	1,513	605	2,664	2,286

*Industrial includes natural gas demand for thermal enhanced oil recovery serve by both utilities and interstate pipelines.
**Electricity generation include all co-generation natural gas demand.

APPENDIX D

Transportation Costs, Capacities, Line Losses for NARG Model Corridors

Table D-1
Transportation Costs, Capacities, Line Losses for NARG Model Corridors

NARG Sector	NARG Activity	Interstate Pipeline Corridors	2003 Assessment 2000$/MCF	Maximum Pipeline Capacity		Line Losses	Source of Transport Cost & Description of pipeline
				TCF/YR	BCF/D		
1	5	ANGTS to Alberta	4.750	0.700	1.918	8.00%	Literature review
1	6	TAGS to S Alaska	1.869	N/A	N/A	3.00%	1995 Fuels Report
2	9	S Alaska to Asia	1.765	0.063	0.173	0.00%	1995 Fuels Report
3	11	San Juan to Topock (EP-N)	0.164	1.240	3.397	2.50%	50% of EPNG/TW SJ-CA Rate
3	6	San Juan to Rocky Mtns	0.276	0.122	0.334	1.50%	Northwest Pipeline
3	18	San Juan to Anadarko	0.279	0.035	0.096	1.60%	CIG Rate (Off-System)
3	9	San Juan to Permian	0.175	0.448	1.227	5.00%	EPNG/TW Combined
3	5	Topock to EOR (Via Mojave)	0.330	0.146	0.400	0.00%	50% EPNG: SJ to CA Border + Mojave
3	27	Topock to Southern CA Supply (Via EP-N)	0.000	0.526	1.441	0.00%	50% EPNG/TW SJ-CA Rate
3	4	Topock to Northern CA Supply (Via EP-N)	0.000	1.188	3.255	0.00%	50% EPNG/TW SJ-CA Rate
3	7	Topock to SW Desert - AZ/NM (Via EP-N)	0.084	0.292	0.800	2.50%	EPNG SJ to AZ/NM Tariff - NARG Rate (SJ-Topock)
3	13	Topock to Blythe (Via Havasu Crossover)	0.000	0.231	0.633	0.00%	Rate Incorporated in Other Corridors
3	15	Topock to SW Desert - NV (Via EP-N)	0.115	0.082	0.225	2.50%	EPNG SJ to NV Tariff - NARG Rate (SJ-Topock)
4	18	Rocky Mtns to EOR (Through 2009)	0.417	0.637	1.745	1.00%	100% Kern River
4	14	Rocky Mtns to San Juan Basin	0.287	0.233	0.638	1.50%	Northwest Pipeline
4	15	Rocky Mtns to WNC Demand	0.340	0.601	1.647	0.50%	Trailblazer, KN Interstate
4	16	Rocky Mtns to Rocky Mtn Demand	0.192	0.571	1.564	1.50%	Questar Pipeline, CIG (On-System Rate)
4	17	Rocky Mtn to Anadarko	0.237	0.306	0.838	1.60%	CIG, Williams Natural Gas, KN Interstate
4	25	Rocky Mtn to Pacific Northwest	0.287	0.162	0.444	1.60%	Northwest Pipeline
5	13	NGPlains to Rocky Mtn Demand (Montana)	0.350	0.127	0.348	3.40%	Williston Basin

Table D-1 (Continued)
Transportation Costs, Capacities, Line Losses for NARG Model Corridors

NARG Sector	NARG Activity	Interstate Pipeline Corridors	2003 Assessment 2000$/MCF	Maximum Pipeline Capacity		Line Losses	Source of Transport Cost & Description of pipeline
				TCF/YR	BCF/D		
5	14	NGPlains to WNC Demand	0.350	0.096	0.263	3.40%	Williston Basin
5	16	NGPlains to Rocky Mtn Demand (WY/CO)	0.174	0.120	0.329	1.40%	CIG (On-System Rate)
6	4	Anadarko to WNC Demand	0.193	2.207	6.047	2.90%	Northern Natural, Panhandle Eastern, Williams, KN Interstate
6	6	Anadarko to Permian Basin	0.108	0.735	2.014	1.40%	EPNG (Anadarko-Production Area)
6	7	Anadarko to WSC Demand	0.199	3.016	8.263	1.20%	Spot Price Differential (1/95-12/95)
6	8	Anadarko to ESC Demand	0.257	0.188	0.515	2.50%	Noram Gas Transmission
7	11	Permian to El Paso -South Allocation (Blythe)	0.183	0.887	2.430	2.50%	50% of EPNG: Permian to CA
7	7	Permian to Anadarko	0.108	0.905	2.479	1.40%	EPNG (Permian-Production Area)
7	9	Permian to WSC Demand	0.095	0.481	1.318	1.20%	Valero
7	10	Permian to San Juan (EP-N)	0.000	0.570	1.562	2.50%	Rate Incorporated in Other Corridors
7	13	Permian to Gulf	0.243	0.631	1.729	1.00%	Valero
7	8	Blythe (EP-S Allocation) to SW Desert - AZ/NM	0.077	0.185	0.507	2.50%	EPNG Permian to AZ/NM Tariff - NARG Rate (Permian-Blythe)
7	12	Blythe (EP-S Allocation) to Mexico	0.077	0.168	0.460	2.50%	EPNG Permian to AZ/NM Tariff - NARG Rate (Permian-Blythe)
7	21	Blythe to Southern CA Supply (Via EP-S)	0.162	0.683	1.871	2.50%	50% of EPNG: Permian to CA
8	8	Gulf Coast to WSC Demand	0.132	7.290	19.973	1.10%	Tennessee Gas, Transcontinental, Texas Eastern
8	9	Gulf Coast to Permian Basin	0.243	0.420	1.151	1.00%	Valero
8	10	Gulf Coast to ESC Demand	0.179	7.584	20.778	1.20%	Tennessee Gas, Transcontinental, Texas Eastern, Southern Natural
8	15	Gulf Coast to Mexico Demand (East)	0.042	0.494	1.353	0.50%	
9	8	N Central to ENC Demand	0.319	0.408	1.118	3.00%	East Ohio Off-System Rate

Table D-1 (Continued)
Transportation Costs, Capacities, Line Losses for NARG Model Corridors

NARG Sector	NARG Activity	Interstate Pipeline Corridors	2003 Assessment 2000$/MCF	Maximum Pipeline Capacity TCF/YR	BCF/D	Line Losses	Source of Transport Cost & Description of pipeline
9	9	N Central to ESC Demand	0.319	0.073	0.200	5.00%	East Ohio Off-System Rate
10	11	Appalachia to S Atantic Demand	0.248	0.622	1.704	2.30%	Columbia Gas
10	12	Appalachia to Mid-Atlantic Demand	0.178	0.664	1.819	2.40%	National Fuel, Columbia Gas, CNG, Equitrans
12	3	Mexico to Gulf Coast	1.090	0.500	1.370	0.00%	
13	10	Sumas to Pacific NW	0.287	0.399	1.093	1.60%	Northwest Pipeline
13	11	S Alberta to Rocky Mtn Demand (Montana)	0.189	0.040	0.110	2.00%	Montana Power
13	7	S Alberta to Stanfield	0.121	0.909	2.490	1.10%	45.3% of PGT Rolled-in Tariff
13	15	Stanfield to Pacific NW (Reno Lateral)	0.327	0.198	0.542	2.60%	Northwest Pipeline
13	21	Stanfield to Malin	0.146	0.781	2.140	1.40%	54.7% of PGT Rolled-in Tariff
13	22	Stanfield to PNW Demand (Via NWPL)	0.327	0.091	0.249	1.50%	Northwest Pipeline
13	9	Malin to PG&E (PG&E Line 400)	0.052	0.219	0.600	0.00%	PG&E Noncore Backbone Rate (Reported in Gas Accord Filing)
13	8	Malin to Southern CA Supply (PG&E Line 401)	0.127	0.219	0.600	1.10%	PG&E Tariffs)
13	19	Malin to Northern CA Supply (PG&E Line 401)	0.000	0.239	0.655	0.00%	PG&E Tariffs)
13	24	Malin to PNW Demand (Reno)	0.488	0.041	0.112	2.00%	Tuscarora Pipeline
13	12	East Montana to WNC (Northern Border)	0.350	0.800	2.192	2.70%	Northern Border (Monchy-Ventura)
13	16	WNC to ENC (Northern Border)	0.140	0.492	1.348	1.30%	Northern Border (Ventura-Harper and Harper-Manhattan)
13	13	West Minn to ENC	0.227	0.494	1.353	1.30%	Viking Gas, Great Lakes
13	14	New York to Mid Atlantic	0.347	0.756	2.071	1.60%	Tennessee Gas, Iroquois
13	20	Vermont to New England	0.346	0.023	0.063	0.50%	
14	3	LNG to Gulf	1.860	0.986	2.701	0.00%	2003 Natural Gas Market Assessment

Table D-1 (Continued)
Transportation Costs, Capacities, Line Losses for NARG Model Corridors

NARG Sector	NARG Activity	Interstate Pipeline Corridors	2003 Assessment 2000$/MCF	Maximum Pipeline Capacity		Line Losses	Source of Transport Cost & Description of pipeline
				TCF/YR	BCF/D		
14	4	LNG to So Atlantic	1.860	0.294	0.805	0.00%	2003 Natural Gas Market Assessment
14	5	LNG to Mid Atlantic	1.860	0.365	1.000	0.00%	2003 Natural Gas Market Assessment
14	9	LNG to New England	1.860	0.334	0.915	0.00%	2003 Natural Gas Market Assessment
15	7	Pacific NW to PGT for Delivery to CA Border	0.000	0.073	0.200	0.00%	Incorporated in Other Corridors
15	8	Pacific NW to Rocky Mtn Supply	0.000	0.109	0.299	0.00%	Incorporated in Other Corridors
15	9	Pacific NW to PNW Demand (Reno)	0.269	0.078	0.214	2.50%	Paiute Pipeline
15	10	Pacific NW to Rocky Mtn Demand (Idaho)	0.000	N/A	N/A	1.50%	Incorporated in Other Corridors
16	14	WNC to ENC (Except Northern Border)	0.149	1.769	4.847	2.90%	Northern Natural, Panhandle Eastern
18	9	ENC to Mid-Atlantic	0.306	1.650	4.521	1.90%	Texas Eastern, Tennessee Gas, CNG
18	10	ENC to Ontario	0.147	0.071	0.195	1.00%	Panhandle Eastern
					0.000		
19	13	ESC to ENC	0.307	4.223	11.570	3.00%	Texas Eastern, Tennessee Gas
19	14	ESC to So Atlantic	0.147	3.391	9.290	1.70%	Transcontental, Southern Natural
20	13	So Atlantic to Mid-Atlantic	0.178	1.021	2.797	2.30%	Transco, Columbia, CNG
21	13	Mid-Atlantic to New England	0.252	0.764	2.093	1.20%	Tennessee Gas, Algonquin, Iroquois
23	2	Southern CA Supply to SoCalGas	0.072	1.000	2.740	0.50%	
23	3	Southern CA Supply to SDG&E	0.375	0.146	0.400	0.50%	SoCalGas Tariff Sheet 27591-G, Effective 1/1/96.
23	4	Southern CA Supply to EOR	0.102	0.146	0.400	0.50%	Avg California Transport Rate
23	13	Southern CA Supply (Wheeler Ridge)	0.104	0.292	0.800	0.00%	
23	14	Southern CA Supply Direct Link	0.102	0.256	0.701	0.50%	Avg California Transport Rate

Table D-1 (Continued)
Transportation Costs, Capacities, Line Losses for NARG Model Corridors

NARG Sector	NARG Activity	Interstate Pipeline Corridors	2003 Assessment 2000$/MCF	Maximum Pipeline Capacity TCF/YR	BCF/D	Line Losses	Source of Transport Cost & Description of pipeline
23	21	San Joaquin Valley Trans	0.104	0.471	1.290	0.00%	
24	2	Northern CA Supply to PG&E	0.000	0.964	2.641	0.00%	PG&E Noncore Backbone Rate (Reported in Gas Accord Filing)
24	10	Northern CA Supply Direct Link	0.102	0.110	0.301	2.00%	Avg California Transport Rate
25	13	SoCalGas to EOR	0.282	0.160	0.438	0.50%	
26	13	PG&E to EOR	N/A	0.000	0.000	0.50%	
28	5	EOR to Southern CA Supply	0.000	0.146	0.400	0.00%	
28	4	EOR to Northern CA Supply (Via KR/Mojave)	0.000	0.073	0.200	0.00%	PG&E Kern River Station Charge
1,2	9	BC to BC Demand	0.164	0.287	0.786	1.60%	Westcoast Inland Toll
1,2	5	BC to Washington	0.241	0.405	1.110	1.60%	Westcoast to Alberta Toll
1,2	6	BC to Alberta	0.073	0.405	1.110	1.00%	Westcoast Export Toll
2,2	5	Alberta to Western Canada	0.109	1.071	2.934	1.20%	NOVA Provincial
2,2	6	Alberta to East Montana	0.277	0.818	2.240	1.20%	NOVA export + Foothills to N.Border
2,2	7	Alberta to Saskatchewan	0.311	2.332	6.389	1.20%	NOVA export + TCPL to Saskatchewan
2,2	8	Alberta to S Alberta	0.268	1.190	3.260	1.20%	NOVA export + ANG to PGT
3,2	4	Saskatchewan to Western Canada	0.227	0.206	0.564	1.30%	TCPL to Saskatchewan + NOVA Provincial
3,2	5	Saskatchewan to Ontario	0.438	2.332	6.389	1.30%	TCPL to N Ontario - Saskatchewan
3,2	6	Saskatchewan to West Minn	0.122	0.494	1.353	1.30%	TCPL to Emerson - Saskatchewan
4,2	4	N Canada Supply to Alberta	1.599	0.438	1.200	4.00%	
5,2	4	E Canada Supply to New England	1.007	0.146	0.400	1.00%	Natural GasTrade Publications
7,2	7	E Canada Demand to Vermont	0.000	N/A	N/A	N/A	Incorporated in Other Corridors
9,2	7	Ontario Demand to East Canada Demand	0.124	0.438	1.200	3.00%	TCPL to East of Ontario - N Ontario
9,2	8	Ontario to New York	0.163	N/A	N/A	1.40%	TCPL to Niagara - N Ontario

APPENDIX E

End-Use Natural Gas Price Forecast by Sector

Table E-1

PG&E

Basecase Price Forecast 04-08-2003

End-use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.73	6.64	5.87	3.80	4.13	3.08	3.82	3.82	4.89
1991	6.76	6.75	5.91	3.14	3.29	3.64	3.30	3.30	4.58
1992	6.50	7.10	5.29	3.04	2.43	2.86	3.01	3.01	4.14
1993	6.15	6.58	5.21	3.26	2.41	2.56	3.25	3.25	4.29
1994	6.40	6.62	5.10	3.16	2.15	2.14	2.43	2.43	3.87
1995	6.67	6.73	4.90	2.65	1.94	1.60	2.36	2.36	4.00
1996	6.02	6.01	4.94	3.41	2.42	2.10	2.48	2.48	4.04
1997	6.21	6.22	5.31	2.89	2.83	3.12	2.81	2.81	4.08
1998	6.14	7.41	4.29	3.33	2.67	2.48	2.63	2.63	4.13
1999	7.57	7.54	4.30	3.91	2.89	2.79	2.71	2.71	4.30
2000	8.86	8.86	6.43	6.09	5.32	5.18	5.25	5.25	6.38
2001	9.76	9.69	7.60	7.60	6.83	6.80	6.81	6.81	7.72
2002	6.68	6.61	4.44	4.06	3.24	3.22	3.22	3.22	4.34
2003	6.72	6.65	4.53	4.24	3.41	3.40	3.39	3.39	4.40
2004	6.80	6.74	4.63	4.36	3.51	3.51	3.49	3.49	4.45
2005	6.77	6.71	4.68	4.42	3.60	3.59	3.58	3.58	4.48
2006	6.86	6.80	4.78	4.52	3.69	3.69	3.67	3.67	4.55
2007	7.03	6.96	4.91	4.65	3.81	3.82	3.78	3.78	4.68
2008	7.00	6.94	4.94	4.66	3.84	3.86	3.82	3.82	4.70
2009	7.06	7.00	5.01	4.73	3.91	3.93	3.89	3.89	4.76
2010	7.13	7.07	5.08	4.80	3.98	4.01	3.96	3.96	4.84
2011	7.13	7.08	5.13	4.86	4.06	4.08	4.03	4.03	4.88
2012	7.15	7.09	5.18	4.93	4.14	4.16	4.11	4.11	4.95
2013	7.24	7.18	5.26	5.01	4.21	4.23	4.19	4.19	5.03
2014	7.22	7.17	5.31	5.06	4.29	4.31	4.27	4.27	5.08
2015	7.27	7.21	5.38	5.14	4.37	4.39	4.35	4.35	5.15
2016	7.32	7.27	5.45	5.21	4.46	4.47	4.44	4.44	5.22
2017	7.36	7.31	5.52	5.29	4.55	4.56	4.52	4.52	5.30
2018	7.40	7.35	5.59	5.37	4.63	4.63	4.61	4.61	5.37
2019	7.46	7.40	5.66	5.45	4.72	4.72	4.70	4.70	5.45
2020	7.52	7.47	5.74	5.53	4.81	4.81	4.78	4.78	5.53
2021	7.58	7.53	5.81	5.62	4.90	4.90	4.88	4.88	5.61
2022	7.65	7.60	5.89	5.73	5.01	5.01	4.98	4.98	5.71

Note: Residential, commercial, industrial, and TEOR
1990 - 1997 from QFER Form 7
1998 to 2002 based on annual border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.

Table E-2
SoCalGas
Basease Price Forecast 04-08-03
End-use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

		Core		Noncore					System
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	EG	Average
1990	6.71	7.10	6.28	4.48	3.98	3.54	3.85	3.85	4.75
1991	7.33	7.70	7.70	4.10	3.82	3.00	3.38	3.38	4.72
1992	7.56	8.00	7.21	5.64	4.23	3.18	3.29	3.29	5.21
1993	7.36	7.84	7.14	5.22	3.91	3.31	3.30	3.30	5.18
1994	7.25	7.54	7.01	3.48	3.08	2.60	2.77	2.77	4.90
1995	7.52	7.42	6.56	2.51	2.40	2.10	2.37	2.37	4.71
1996	7.08	6.46	5.54	2.95	2.80	2.56	3.09	3.09	4.78
1997	7.38	6.70	5.63	3.11	3.45	3.01	3.36	3.36	4.93
1998	7.34	6.00	5.05	2.95	3.06	2.92	2.96	2.96	4.78
1999	6.26	4.73	3.67	3.11	3.11	3.00	2.77	2.77	4.17
2000	8.47	6.92	5.17	5.20	5.20	5.13	5.05	5.05	6.11
2001	11.49	9.88	8.20	7.16	7.16	7.10	6.99	6.99	8.90
2002	6.69	5.18	3.60	3.40	3.40	3.36	3.23	3.23	4.28
2003	6.94	5.41	3.82	3.55	3.55	3.51	3.35	3.35	4.46
2004	6.94	5.45	3.89	3.63	3.63	3.60	3.44	3.44	4.51
2005	7.05	5.55	3.99	3.74	3.74	3.71	3.53	3.53	4.60
2006	7.03	5.58	4.07	3.83	3.83	3.80	3.64	3.64	4.64
2007	7.15	5.70	4.19	3.97	3.97	3.95	3.79	3.79	4.77
2008	7.17	5.73	4.24	4.04	4.04	4.02	3.86	3.86	4.83
2009	7.23	5.80	4.32	4.13	4.13	4.10	3.99	3.99	4.90
2010	7.28	5.87	4.39	4.21	4.21	4.18	4.07	4.07	4.98
2011	7.32	5.92	4.47	4.29	4.29	4.26	4.15	4.15	5.04
2012	7.42	6.02	4.57	4.39	4.39	4.36	4.21	4.21	5.13
2013	7.55	6.16	4.71	4.47	4.47	4.44	4.29	4.29	5.22
2014	7.66	6.27	4.82	4.56	4.56	4.53	4.38	4.38	5.32
2015	7.73	6.35	4.92	4.64	4.64	4.61	4.46	4.46	5.40
2016	7.81	6.44	5.02	4.73	4.73	4.70	4.55	4.55	5.48
2017	7.79	6.43	5.02	4.75	4.75	4.72	4.57	4.57	5.49
2018	7.97	6.62	5.21	4.90	4.90	4.87	4.73	4.73	5.65
2019	8.05	6.71	5.31	5.00	5.00	4.97	4.82	4.82	5.74
2020	8.12	6.79	5.40	5.08	5.08	5.05	4.91	4.91	5.82
2021	8.19	6.87	5.50	5.17	5.17	5.15	5.00	5.00	5.91
2022	8.30	6.99	5.63	5.29	5.29	5.26	5.12	5.12	6.02

Note: Residential, commercial, industrial, and TEOR
1990 - 1998 from QFER Form 7
1999 to 2002 based on border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.
Impacts of Decision 00-04-060 are included.

Table E-3
SDG&E
Basease Price Forecast 04-08-03
End-Use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

		Core		Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.74	6.71	6.39	4.63	4.63	-	3.89	3.89	5.06
1991	6.35	6.44	6.41	4.07	4.07	-	3.41	3.41	4.61
1992	6.77	6.99	7.08	4.22	4.22	-	3.36	3.36	4.94
1993	7.18	6.76	7.05	2.70	2.61	-	3.49	3.49	5.10
1994	7.22	5.79	6.33	3.77	4.08	-	3.19	3.19	5.00
1995	6.76	5.58	6.26	2.84	2.87	-	2.28	2.28	4.13
1996	6.83	5.91	6.70	3.29	2.94	-	2.66	2.66	4.56
1997	7.53	6.93	7.84	3.40	3.40	-	3.07	3.07	4.74
1998	7.37	6.28	7.28	2.79	2.79	-	2.78	2.78	4.39
1999	7.20	6.50	5.07	3.34	3.34	-	3.21	3.21	4.59
2000	8.82	8.29	6.69	5.55	5.55	-	5.03	5.03	6.32
2001	10.76	10.10	8.48	7.45	7.45	-	6.99	6.99	8.43
2002	7.58	6.87	5.10	3.77	3.77	-	3.20	3.20	5.31
2003	7.54	6.85	5.15	3.89	3.89	-	3.35	3.35	5.36
2004	7.37	6.73	5.14	3.94	3.94	-	3.46	3.46	5.30
2005	7.46	6.82	5.24	4.04	4.04	-	3.56	3.56	5.32
2006	7.42	6.81	5.28	4.12	4.12	-	3.67	3.67	5.33
2007	7.49	6.89	5.39	4.27	4.27	-	3.83	3.83	5.25
2008	7.60	6.99	5.47	4.35	4.35	-	3.90	3.90	5.31
2009	7.70	7.08	5.55	4.44	4.44	-	3.98	3.98	5.41
2010	7.60	7.01	5.55	4.49	4.49	-	4.04	4.04	5.41
2011	7.67	7.07	5.63	4.57	4.57	-	4.12	4.12	5.48
2012	7.84	7.22	5.75	4.68	4.68	-	4.22	4.22	5.61
2013	7.87	7.27	5.81	4.75	4.75	-	4.30	4.30	5.67
2014	7.97	7.36	5.90	4.84	4.84	-	4.39	4.39	5.76
2015	8.05	7.44	5.98	4.93	4.93	-	4.47	4.47	5.85
2016	8.08	7.48	6.04	5.00	5.00	-	4.56	4.56	5.91
2017	8.12	7.52	6.07	5.02	5.03	-	4.58	4.58	5.94
2018	8.25	7.65	6.21	5.18	5.18	-	4.73	4.73	6.08
2019	8.34	7.74	6.30	5.27	5.27	-	4.82	4.82	6.17
2020	8.38	7.79	6.37	5.35	5.35	-	4.91	4.91	6.24
2021	8.43	7.85	6.44	5.44	5.44	-	5.00	5.00	6.32
2022	8.50	7.93	6.54	5.55	5.55	-	5.12	5.12	6.42

Note: Residential, commercial, industrial, and TEOR
1990 - 1998 from QFER Form 7
1999 to 2002 based on border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.
Impacts of Decision 00-04-060 are included.

Table E-4
PG&E
High IPSO Price Forecast 04-08-2003
End-use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

		Core				Noncore			System
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	EG	Average
1990	6.73	6.64	5.87	3.80	4.13	3.08	3.82	3.82	4.89
1991	6.76	6.75	5.91	3.14	3.29	3.64	3.30	3.30	4.58
1992	6.50	7.10	5.29	3.04	2.43	2.86	3.01	3.01	4.14
1993	6.15	6.58	5.21	3.26	2.41	2.56	3.25	3.25	4.29
1994	6.40	6.62	5.10	3.16	2.15	2.14	2.43	2.43	3.87
1995	6.67	6.73	4.90	2.65	1.94	1.60	2.36	2.36	4.00
1996	6.02	6.01	4.94	3.41	2.42	2.10	2.48	2.48	4.04
1997	6.21	6.22	5.31	2.89	2.83	3.12	2.81	2.81	4.08
1998	6.17	7.44	4.31	3.35	2.69	2.50	2.63	2.63	4.15
1999	7.64	7.62	4.37	3.87	2.86	2.77	2.71	2.71	4.31
2000	8.97	8.97	6.55	6.03	5.25	5.12	5.18	5.18	6.36
2001	9.90	9.83	7.74	7.65	6.87	6.85	6.85	6.85	7.80
2002	6.84	6.78	4.61	3.84	3.02	3.02	3.00	3.00	4.25
2003	7.25	7.19	5.07	4.26	3.43	3.43	3.41	3.41	4.57
2004	7.74	7.67	5.56	4.69	3.85	3.85	3.82	3.82	4.96
2005	8.09	8.03	6.01	5.05	4.24	4.24	4.22	4.22	5.31
2006	8.58	8.52	6.49	5.44	4.62	4.63	4.60	4.60	5.70
2007	9.12	9.06	7.00	5.82	4.98	5.00	4.96	4.96	6.10
2008	9.12	9.06	7.06	6.03	5.22	5.23	5.19	5.19	6.28
2009	9.19	9.13	7.14	6.22	5.41	5.43	5.38	5.38	6.43
2010	9.28	9.22	7.22	6.39	5.57	5.60	5.55	5.55	6.58
2011	9.29	9.23	7.28	6.52	5.72	5.74	5.70	5.70	6.68
2012	9.31	9.25	7.34	6.64	5.85	5.87	5.83	5.83	6.78
2013	9.42	9.37	7.45	6.80	6.01	6.03	5.99	5.99	6.93
2014	9.43	9.38	7.52	6.92	6.15	6.17	6.13	6.13	7.03
2015	9.50	9.45	7.62	7.05	6.29	6.31	6.27	6.27	7.15
2016	9.58	9.53	7.71	7.19	6.43	6.44	6.41	6.41	7.28
2017	9.65	9.60	7.81	7.32	6.57	6.58	6.55	6.55	7.39
2018	9.70	9.65	7.89	7.43	6.69	6.70	6.67	6.67	7.49
2019	9.76	9.71	7.96	7.54	6.80	6.81	6.78	6.78	7.59
2020	9.83	9.77	8.04	7.64	6.91	6.92	6.89	6.89	7.69
2021	9.90	9.85	8.13	7.75	7.02	7.03	7.00	7.00	7.79
2022	9.97	9.91	8.21	7.85	7.13	7.13	7.11	7.11	7.89

Note: Residential, commercial, industrial, and TEOR
1990 - 1997 from QFER Form 7
1998 to 2002 based on annual border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.

Table E-5
SoCal Gas
High IPSO Price Forecast 04-08-03
End-use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

Year	Res	Core Comm	Indust	Comm	Indust	Noncore TEOR	Cogen	EG	System Average
1990	6.71	7.10	6.28	4.48	3.98	3.54	3.85	3.85	4.75
1991	7.33	7.70	7.70	4.10	3.82	3.00	3.38	3.38	4.72
1992	7.56	8.00	7.21	5.64	4.23	3.18	3.29	3.29	5.21
1993	7.36	7.84	7.14	5.22	3.91	3.31	3.30	3.30	5.18
1994	7.25	7.54	7.01	3.48	3.08	2.60	2.77	2.77	4.90
1995	7.52	7.42	6.56	2.51	2.40	2.10	2.37	2.37	4.71
1996	7.08	6.46	5.54	2.95	2.80	2.56	3.09	3.09	4.78
1997	7.38	6.70	5.63	3.11	3.45	3.01	3.36	3.36	4.93
1998	7.34	6.00	5.05	2.95	3.06	2.92	2.96	2.96	4.78
1999	6.26	4.73	3.67	3.69	3.69	3.57	2.77	2.77	4.31
2000	8.44	6.90	5.15	5.96	5.96	5.90	5.81	5.81	6.59
2001	12.03	10.42	8.74	7.17	7.17	7.11	7.00	7.00	9.16
2002	6.71	5.20	3.62	4.01	4.01	3.97	3.84	3.84	4.69
2003	7.64	6.11	4.52	4.38	4.38	4.34	4.17	4.17	5.24
2004	7.87	6.37	4.82	4.74	4.74	4.71	4.55	4.55	5.56
2005	8.22	6.72	5.15	5.13	5.13	5.10	4.92	4.92	5.91
2006	8.44	6.99	5.47	5.50	5.50	5.47	5.31	5.31	6.23
2007	8.84	7.39	5.88	5.87	5.87	5.84	5.68	5.68	6.61
2008	8.92	7.48	5.99	5.98	5.98	5.95	5.80	5.80	6.71
2009	9.01	7.59	6.10	6.09	6.09	6.06	5.95	5.95	6.81
2010	9.11	7.69	6.22	6.22	6.22	6.19	6.08	6.08	6.93
2011	9.22	7.82	6.37	6.37	6.37	6.34	6.23	6.23	7.06
2012	9.37	7.98	6.52	6.52	6.52	6.49	6.34	6.34	7.20
2013	9.50	8.11	6.66	6.66	6.66	6.63	6.48	6.48	7.34
2014	9.65	8.26	6.81	6.80	6.80	6.77	6.62	6.62	7.48
2015	9.76	8.38	6.95	6.94	6.94	6.91	6.76	6.76	7.61
2016	9.88	8.51	7.09	7.08	7.08	7.05	6.90	6.90	7.75
2017	9.03	7.67	6.25	7.13	7.13	7.10	6.96	6.96	7.52
2018	10.12	8.76	7.36	7.34	7.34	7.31	7.16	7.16	8.00
2019	10.22	8.88	7.48	7.46	7.46	7.43	7.28	7.28	8.11
2020	10.31	8.98	7.59	7.56	7.56	7.53	7.38	7.38	8.21
2021	10.41	9.09	7.71	7.68	7.68	7.65	7.50	7.50	8.32
2022	10.50	9.19	7.83	7.79	7.79	7.77	7.62	7.62	8.43

Note: Residential, commercial, industrial, and TEOR
1990 - 1998 from QFER Form 7
1999 to 2002 based on border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.
Impacts of Decision 00-04-060 are included.

Table E-6
SDG&E
High IPSO Price Forecast 04-08-03
End-Use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.74	6.71	6.39	4.63	4.63	-	3.89	3.89	5.06
1991	6.35	6.44	6.41	4.07	4.07	-	3.41	3.41	4.61
1992	6.77	6.99	7.08	4.22	4.22	-	3.36	3.36	4.94
1993	7.18	6.76	7.05	2.70	2.61	-	3.49	3.49	5.10
1994	7.22	5.79	6.33	3.77	4.08	-	3.19	3.19	5.00
1995	6.76	5.58	6.26	2.84	2.87	-	2.28	2.28	4.13
1996	6.83	5.91	6.70	3.29	2.94	-	2.66	2.66	4.56
1997	7.53	6.93	7.84	3.40	3.40	-	3.07	3.07	4.74
1998	7.37	6.28	7.28	2.79	2.79	-	2.78	2.78	4.39
1999	7.49	6.80	5.36	3.91	3.91	-	3.21	3.21	4.75
2000	9.21	8.68	7.08	6.31	6.31	-	5.79	5.79	6.95
2001	10.76	10.10	8.48	7.46	7.46	-	7.00	7.00	8.44
2002	7.90	7.18	5.41	4.38	4.38	-	3.81	3.81	5.77
2003	8.08	7.40	5.70	4.72	4.72	-	4.17	4.17	6.04
2004	8.20	7.56	5.97	5.05	5.05	-	4.57	4.57	6.27
2005	8.56	7.93	6.34	5.43	5.43	-	4.95	4.95	6.57
2006	8.80	8.19	6.66	5.79	5.79	-	5.33	5.33	6.87
2007	9.12	8.52	7.02	6.17	6.17	-	5.73	5.73	7.04
2008	9.28	8.67	7.15	6.29	6.29	-	5.84	5.84	7.14
2009	9.42	8.80	7.27	6.40	6.40	-	5.95	5.95	7.28
2010	9.36	8.78	7.32	6.50	6.50	-	6.05	6.05	7.32
2011	9.49	8.89	7.45	6.64	6.65	-	6.20	6.20	7.46
2012	9.71	9.10	7.63	6.81	6.81	-	6.35	6.35	7.64
2013	9.81	9.21	7.75	6.94	6.95	-	6.49	6.49	7.76
2014	9.97	9.36	7.90	7.09	7.09	-	6.63	6.63	7.91
2015	10.11	9.50	8.04	7.23	7.23	-	6.77	6.77	8.05
2016	10.20	9.60	8.16	7.36	7.36	-	6.91	6.91	8.17
2017	10.17	9.57	8.13	7.41	7.41	-	6.96	6.96	8.19
2018	10.45	9.85	8.41	7.62	7.62	-	7.17	7.17	8.43
2019	10.57	9.97	8.53	7.73	7.74	-	7.29	7.29	8.54
2020	10.62	10.04	8.61	7.83	7.83	-	7.39	7.39	8.63
2021	10.70	10.12	8.72	7.94	7.94	-	7.51	7.51	8.73
2022	10.78	10.21	8.82	8.05	8.05	-	7.62	7.62	8.83

Note: Residential, commercial, industrial, and TEOR
1990 - 1998 from QFER Form 7
1999 to 2002 based on border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.
Impacts of Decision 00-04-060 are included.

Table E-7

PG&E

Low IPSO Price Forecast 04-08-2003

End-use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

Year	Core Res	Core Comm	Core Indust	Noncore Comm	Noncore Indust	Noncore TEOR	Cogen	EG	System Average
1990	6.73	6.64	5.87	3.80	4.13	3.08	3.82	3.82	4.89
1991	6.76	6.75	5.91	3.14	3.29	3.64	3.30	3.30	4.58
1992	6.50	7.10	5.29	3.04	2.43	2.86	3.01	3.01	4.14
1993	6.15	6.58	5.21	3.26	2.41	2.56	3.25	3.25	4.29
1994	6.40	6.62	5.10	3.16	2.15	2.14	2.43	2.43	3.87
1995	6.67	6.73	4.90	2.65	1.94	1.60	2.36	2.36	4.00
1996	6.02	6.01	4.94	3.41	2.42	2.10	2.48	2.48	4.04
1997	6.21	6.22	5.31	2.89	2.83	3.12	2.81	2.81	4.08
1998	6.14	7.41	4.28	3.33	2.67	2.48	2.63	2.63	4.13
1999	7.56	7.54	4.30	3.91	2.89	2.79	2.71	2.71	4.29
2000	8.85	8.85	6.42	6.09	5.32	5.18	5.25	5.24	6.37
2001	9.75	9.68	7.59	7.55	6.77	6.74	6.75	6.75	7.68
2002	6.66	6.60	4.43	4.06	3.24	3.22	3.22	3.22	4.34
2003	6.54	6.48	4.36	4.06	3.23	3.22	3.21	3.21	4.22
2004	6.51	6.45	4.34	4.06	3.22	3.21	3.20	3.20	4.16
2005	6.36	6.30	4.27	4.01	3.19	3.18	3.17	3.17	4.07
2006	6.33	6.27	4.24	4.00	3.17	3.17	3.15	3.15	4.03
2007	6.37	6.31	4.25	3.99	3.15	3.16	3.13	3.13	4.02
2008	6.32	6.26	4.26	4.02	3.20	3.22	3.18	3.18	4.05
2009	6.36	6.30	4.31	4.07	3.25	3.27	3.23	3.23	4.09
2010	6.42	6.36	4.36	4.11	3.30	3.32	3.27	3.27	4.14
2011	6.40	6.34	4.39	4.15	3.35	3.37	3.32	3.32	4.17
2012	6.38	6.33	4.41	4.17	3.37	3.40	3.35	3.35	4.18
2013	6.44	6.39	4.47	4.26	3.46	3.48	3.44	3.44	4.26
2014	6.39	6.34	4.48	4.30	3.52	3.54	3.50	3.50	4.29
2015	6.41	6.35	4.52	4.35	3.59	3.60	3.57	3.57	4.34
2016	6.43	6.38	4.57	4.41	3.65	3.66	3.63	3.63	4.40
2017	6.44	6.39	4.60	4.44	3.69	3.70	3.67	3.67	4.42
2018	6.47	6.41	4.65	4.52	3.78	3.79	3.76	3.76	4.50
2019	6.50	6.45	4.70	4.58	3.84	3.85	3.82	3.82	4.55
2020	6.54	6.49	4.76	4.64	3.91	3.91	3.89	3.89	4.61
2021	6.58	6.53	4.81	4.70	3.97	3.98	3.95	3.95	4.67
2022	6.62	6.57	4.87	4.73	4.01	4.01	3.99	3.99	4.70

Note: Residential, commercial, industrial, and TEOR
1990 - 1997 from QFER Form 7
1998 to 2002 based on annual border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.

Table E-8

SoCal Gas

Low IPSO Price Forecast 04-08-03

End-use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

		Core				Noncore			System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.71	7.10	6.28	4.48	3.98	3.54	3.85	3.85	4.75
1991	7.33	7.70	7.70	4.10	3.82	3.00	3.38	3.38	4.72
1992	7.56	8.00	7.21	5.64	4.23	3.18	3.29	3.29	5.21
1993	7.36	7.84	7.14	5.22	3.91	3.31	3.30	3.30	5.18
1994	7.25	7.54	7.01	3.48	3.08	2.60	2.77	2.77	4.90
1995	7.52	7.42	6.56	2.51	2.40	2.10	2.37	2.37	4.71
1996	7.08	6.46	5.54	2.95	2.80	2.56	3.09	3.09	4.78
1997	7.38	6.70	5.63	3.11	3.45	3.01	3.36	3.36	4.93
1998	7.34	6.00	5.05	2.95	3.06	2.92	2.96	2.96	4.78
1999	6.26	4.72	3.66	3.65	3.64	3.53	2.77	2.77	4.30
2000	8.47	6.92	5.18	5.92	5.92	5.85	5.77	5.77	6.57
2001	12.03	10.42	8.74	7.25	7.25	7.20	7.08	7.08	9.20
2002	6.70	5.19	3.61	3.96	3.96	3.92	3.80	3.80	4.66
2003	6.70	5.17	3.58	3.93	3.93	3.89	3.72	3.72	4.63
2004	6.62	5.13	3.57	3.92	3.92	3.89	3.73	3.73	4.60
2005	6.66	5.16	3.60	3.94	3.94	3.91	3.73	3.73	4.60
2006	6.57	5.12	3.60	3.94	3.94	3.91	3.75	3.75	4.57
2007	7.01	5.56	4.05	3.94	3.94	3.91	3.75	3.75	4.70
2008	7.02	5.59	4.09	3.98	3.98	3.95	3.80	3.80	4.75
2009	7.05	5.62	4.14	4.03	4.03	4.00	3.89	3.89	4.78
2010	7.08	5.66	4.19	4.09	4.09	4.06	3.95	3.95	4.84
2011	7.12	5.72	4.27	4.18	4.18	4.15	4.04	4.04	4.90
2012	7.21	5.81	4.35	4.27	4.27	4.24	4.09	4.09	4.97
2013	7.26	5.87	4.43	4.34	4.34	4.31	4.16	4.16	5.04
2014	7.35	5.96	4.51	4.41	4.41	4.38	4.23	4.23	5.12
2015	7.39	6.01	4.58	4.48	4.48	4.45	4.30	4.30	5.18
2016	7.44	6.07	4.65	4.55	4.55	4.52	4.37	4.37	5.24
2017	7.86	6.50	5.09	4.64	4.64	4.62	4.47	4.47	5.44
2018	7.56	6.20	4.80	4.68	4.68	4.65	4.51	4.51	5.37
2019	7.61	6.27	4.87	4.75	4.75	4.72	4.57	4.57	5.43
2020	7.64	6.31	4.92	4.79	4.79	4.76	4.61	4.61	5.47
2021	7.69	6.37	4.99	4.85	4.85	4.82	4.67	4.67	5.53
2022	7.73	6.43	5.06	4.91	4.91	4.88	4.74	4.74	5.59

Note: Residential, commercial, industrial, and TEOR
1990 - 1998 from QFER Form 7
1999 to 2002 based on border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.
Impacts of Decision 00-04-060 are included.

Table E-9

SDG&E

Low IPSO Price Forecast 04-08-03

End-Use Natural Gas Price Forecast by Sector

2000 Dollars per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.74	6.71	6.39	4.63	4.63	-	3.89	3.89	5.06
1991	6.35	6.44	6.41	4.07	4.07	-	3.41	3.41	4.61
1992	6.77	6.99	7.08	4.22	4.22	-	3.36	3.36	4.94
1993	7.18	6.76	7.05	2.70	2.61	-	3.49	3.49	5.10
1994	7.22	5.79	6.33	3.77	4.08	-	3.19	3.19	5.00
1995	6.76	5.58	6.26	2.84	2.87	-	2.28	2.28	4.13
1996	6.83	5.91	6.70	3.29	2.94	-	2.66	2.66	4.56
1997	7.53	6.93	7.84	3.40	3.40	-	3.07	3.07	4.74
1998	7.37	6.28	7.28	2.79	2.79	-	2.78	2.78	4.39
1999	7.20	6.50	5.07	3.34	3.34	-	3.21	3.21	4.59
2000	8.82	8.29	6.69	5.55	5.55	-	5.03	5.03	6.32
2001	10.76	10.10	8.48	7.45	7.45	-	6.99	6.99	8.43
2002	7.58	6.87	5.10	3.77	3.77	-	3.20	3.20	5.31
2003	7.54	6.85	5.15	3.89	3.89	-	3.35	3.35	5.36
2004	7.37	6.73	5.14	3.94	3.94	-	3.46	3.46	5.30
2005	7.46	6.82	5.24	4.04	4.04	-	3.56	3.56	5.32
2006	7.42	6.81	5.28	4.12	4.12	-	3.67	3.67	5.33
2007	7.49	6.89	5.39	4.27	4.27	-	3.83	3.83	5.25
2008	7.60	6.99	5.47	4.35	4.35	-	3.90	3.90	5.31
2009	7.70	7.08	5.55	4.44	4.44	-	3.98	3.98	5.41
2010	7.60	7.01	5.55	4.49	4.49	-	4.04	4.04	5.41
2011	7.67	7.07	5.63	4.57	4.57	-	4.12	4.12	5.48
2012	7.84	7.22	5.75	4.68	4.68	-	4.22	4.22	5.61
2013	7.87	7.27	5.81	4.75	4.75	-	4.30	4.30	5.67
2014	7.97	7.36	5.90	4.84	4.84	-	4.39	4.39	5.76
2015	8.05	7.44	5.98	4.93	4.93	-	4.47	4.47	5.85
2016	8.08	7.48	6.04	5.00	5.00	-	4.56	4.56	5.91
2017	8.12	7.52	6.07	5.02	5.03	-	4.58	4.58	5.94
2018	8.25	7.65	6.21	5.18	5.18	-	4.73	4.73	6.08
2019	8.34	7.74	6.30	5.27	5.27	-	4.82	4.82	6.17
2020	8.38	7.79	6.37	5.35	5.35	-	4.91	4.91	6.24
2021	8.43	7.85	6.44	5.44	5.44	-	5.00	5.00	6.32
2022	8.50	7.93	6.54	5.55	5.55	-	5.12	5.12	6.42

Note: Residential, commercial, industrial, and TEOR
1990 - 1998 from QFER Form 7
1999 to 2002 based on border prices and distribution cost allocation.

Cogeneration and electric generation
1990 - 1998 total prices are historical, obtained from UMFOR.
1999 to 2002 based on annual border prices and tarrifs.

All other years are forecasted.
Impacts of Decision 00-04-060 are included.

APPENDIX F

GDP Implicit Price Deflator

Table F-1
GDP Implicit Price Deflator (2001 = 100) (5/15/2002)

YEAR	INDEX	ANNUAL GROWTH RATE
1970	26.57	5.3%
1971	27.91	5.0%
1972	29.10	4.2%
1973	30.73	5.6%
1974	33.49	9.0%
1975	36.61	9.3%
1976	38.68	5.7%
1977	41.17	6.4%
1978	44.10	7.1%
1979	47.78	8.3%
1980	52.16	9.2%
1981	57.03	9.3%
1982	60.59	6.2%
1983	62.99	4.0%
1984	65.33	3.7%
1985	67.39	3.2%
1986	68.87	2.2%
1987	70.93	3.0%
1988	73.35	3.4%
1989	76.14	3.8%
1990	79.12	3.9%
1991	81.98	3.6%
1992	83.98	2.4%
1993	86.00	2.4%
1994	87.79	2.1%
1995	89.70	2.2%
1996	91.44	1.9%
1997	93.22	1.9%
1998	94.37	1.2%
1999	95.70	1.4%
2000	97.87	2.3%
2001	100.00	2.2%
2002	101.43	1.4%
2003	102.78	1.3%
2004	106.60	3.7%
2005	110.43	3.6%
2006	114.25	3.5%
2007	116.87	2.3%
2008	119.18	2.0%
2009	121.39	1.9%
2010	123.65	1.9%
2011	126.04	1.9%
2012	128.62	2.0%
2013	131.32	2.1%
2014	134.08	2.1%
2015	136.93	2.1%

YEAR	INDEX	ANNUAL GROWTH RATE
2016	139.81	2.1%
2017	142.74	2.1%
2018	145.74	2.1%
2019	148.79	2.1%
2020	151.94	2.1%
Source:	1970 - 1985 Historic DRI-WEFA	1986-2003 UCLA March 2002
	2004-2005 adjusted	2006 - 2020 UCLA September 2001