Title
California Natural Gas Storage Utilization and Economic Analysis

Author
Hammerschmidt, Andrew

Publication Date
2008-06-01

Arnold Schwarzenegger
Governor

CALIFORNIA NATURAL GAS STORAGE UTILIZATION AND ECONOMIC ANALYSIS

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Gas Technology Institute

June 2008
CEC-500-02-004

Prepared By:
Gas Technology Institute
Mr. Andrew Hammerschmidt
Des Plaines, IL 60018
Commission Contract No. MNG-07-03
Commission Work Authorization No: MR-057

Prepared For:
Public Interest Energy Research (PIER) Program
California Energy Commission

Mr. Brad Niess
Contract Manager

Mr. David Michel
Program Area Lead

Martha Krebs
Deputy Director
ENERGY RESEARCH & DEVELOPMENT DIVISION

Acknowledgements

Gas Technology Institute would like to express our sincere appreciation and gratitude to the many organizations and individuals who contributed to the research within this report. The outstanding support from our two primary sponsoring partners, Southern California Gas Company and the Pacific Gas and Electric Company, included providing critical operating data and operating expertise as well as general counsel to ensure research relevancy to the consumers of the State of California. Other key contributors to this report include research and private organizations leading national and international efforts in developing innovative alternative gas storage technology solutions. These critical research and development efforts are focused on securing stable and economical storage, transportation, and delivery of natural gas to California consumers well into the future.

Gas Technology Institute would also like to provide special recognition to the following key contributors:

Southern California Gas Company	*Rudy Weibel* *Tom Ishii* *Jim Mansdorfer*
Pacific Gas and Electric Company	*Bob Cowden* *Paul Brooks*
Expansion Energy LLC	*David Vandor*
Advantica	*Lay Yen Lau* *Robert Judd*
EnerSea Transport LLC	*Paul Britton*
Northstar Industries LLC	*T. Quine*

Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

What follows is the final report for the California Natural Gas Storage Utilization and Economic Analysis, Contract No. MNG-07-03, conducted by Gas Technology Institute. This project contributes to the Natural Gas program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

Hammerschmidt, Andrew, Ron Edelstein, Lou Lautman, Iraj Salehi, and David Zuckerman. 2008. California Natural Gas Storage Utilization and Economic Analysis. Gas Technology Institute. CEC-500-2008-02-004

Table of Contents

1.0 Executive Summary 2
2.0 Introduction 6
2.1. Background and Overview 6
2.2. Project Objectives/Report Organization 7
3.0 Define California Market Demand Fluctuations and Trending 9
3.1. Project Approach 9
Data Collection 9
North Region 9
South Region 10
Market Segment Definitions 10
Reference Research 11
Data Analysis 12
Historical Growth Trends 12
Seasonal Variations 12
Natural Gas Storage Utilization 12
Hourly Demand Variations 12
Peak Day Demand Forecast 13
Establish Trends and Identify Potential Impact 13
3.2. Project Outcomes 13
California Natural Gas Demand Summary 13
NORTHERN CALIFORNIA REGION 18
Historical Data 18
Forecast Data 18
Market Sectors 18
North Region Natural Gas Demand Trends 22
SOUTHERN CALIFORNIA REGION 33
Historical Data 33
Forecast Data 33
Market Sectors 34
South Region Gas Demand Trends 37
3.3. Conclusions and Recommendations 48
4.0 Define California Natural Gas Storage Deliverability Options 51
4.1. Project Approach 51
Introduction 51
Technology Selection Criteria 51
Technology Review 52
Technology Description 52
Operational Feasibility 52

Economic Feasibility 54
Technology Status 55
4.2. Project Outcomes 55
Conventional Gas Storage Deliverability Enhancement Technologies 55
Hydraulic Fracturing 55
Advanced Drilling Techniques 66
Laser-based Drilling and Completion Technology 70
Summary of Technologies 77
Alternative Natural Gas Storage Technology Review 78
Adsorbed Natural Gas 78
Small Scale LNG Technology 94
Compressed Natural Gas 103
Cold Compressed Natural Gas 115
Advanced Natural Gas Hydrate Storage 132
Lined Rock Cavern 136
4.3 Conclusions and Recommendations 140
Adsorbed Natural Gas 140
Small Scale LNG Technology 140
Compressed Natural Gas 141
Cold Compressed Natural Gas 141
Natural Gas Hydrates and Lined Rock Caverns 141
Summary of Technologies 143
5.0 Regulatory/Policy Review 145
5.1. Project Approach 145
Federal and State Policies, Regulations and Decisions Review 145
Environmental and Safety Concerns 146
Alternative Gas Storage Regulatory Review 146
Market-Based Rate Approval Process Review 146
5.2. Project Outcomes 146
Federal Policies, Legislation, Regulations, and Decisions Review 147
California Policies, Legislation, Regulations, and Decisions Review 149
Environmental and Safety Considerations 150
Alternative Gas Storage Regulatory Review 167
Market-Based Rate Approval Process Review 168
5.3. Conclusions and Recommendations 177
6.0 References 180
7.0 Section 3.0 Appendix 182
7.1. Northern California Region 182

Historical Raw Data Tables 182
Forecast Data Table 187
7.2. Southern California Region 200
Historical Raw Data Tables 200
Forecast Data Table 206
8.0 Section 4.0 Appendix 217
8.1. CNG Technology 217
Functional Testing of System 217
Case-Specific Conceptual Design V800 “Vertical Cylinders V-Ship” 219
Maritime Work Program 219
VOTRANS Gas Handling System Study Report (Fluor Daniels) 220
EnerSea Intellectual Property 220
8.2. CCNG Technology 221
CCNG Comprehensive Solutions 222
VPX System 223
VPX Technology Status 224
9.0 Section 5.0 Appendix 225
9.1. Review of Federal and State Storage Expansion Decisions 225
Introduction 225

Table of Figures

Figure 1 California Demand Growth Comparisons ... 15
Figure 2 NR Residential Demand Forecast ... 19
Figure 3 NR Commercial Demand Forecast ... 20
Figure 4 NR Industrial Demand Forecast ... 20
Figure 5 NR Electrical Generation Demand Forecast ... 21
Figure 6 NR Historic Core Usage Trend ... 22
Figure 7 NR Core Usage Trend Forecast ... 23
Figure 8 NR Historic EG Trend ... 23
Figure 9 NR EG/Cogen Demand Trend Forecast ... 24
Figure 10 NR Total Demand Trend Forecast ... 24
Figure 11 NR 2002/2003 Gas Storage Utilization ... 25
Figure 12 NR 2003/2004 Gas Storage Utilization ... 26
Figure 13 NR 2004/2005 Gas Storage Utilization ... 26
Figure 14 NR 2005/2006 Gas Storage Utilization ... 27
Figure 15 NR Hourly Trend – Low EG Demand Day ... 29
Figure 16 NR Hourly Trend – High EG Demand Day ... 29
Figure 17 EG Contribution to Total System Sendout ... 30
Figure 18 NR Hourly Trend Forecast ... 30
Figure 19 SR Residential Demand Forecast ... 34
Figure 20 SR Commercial Demand Forecast ... 34
Figure 21 SR Industrial Demand Forecast ... 36
Figure 22 SR Electrical Generation Demand Forecast ... 37
Figure 23 SR Historic Core Usage ... 38
Figure 24 SR Core Trend Forecast ... 38
Figure 25 SR Historic Non-Core Usage ... 39
Figure 26 SR Non-Core Trend Forecast ... 39
Figure 27 SR Total Sendout Trend Forecast ... 40
Figure 28 SR 2002/2003 Gas Storage Utilization ... 41
Figure 29 SR 2003/2004 Gas Storage Utilization ... 41
Figure 30 SR 2004/2005 Gas Storage Utilization ... 41
Figure 31 SR 2005/2006 Gas Storage Utilization ... 42
Figure 32 SR 2006/2007 Gas Storage Utilization ... 42
Figure 33 SR Core and EG Hourly Trend ... 44

Figure 34 NR Hourly Usage by Sector 44
Figure 35 SR Hourly Projection 45
Figure 36 Vertical Fracture Containment Model Illustrations 59
Figure 37 Effects of Stress Contrast on Fracture Height Growth 59
Figure 38 Effects of Pore Pressure on Fracturing Pressure 61
Figure 39 Principles of Seismic Fracture Mapping 61
Figure 40 Microseismic Imaging Results from Fracture Modeling and Fracture Diagnostic Survey 62
Figure 41 Principal Ground Deformations Resulting from Hydraulic Fracturing 64
Figure 42 Ground Deformation Resulting from Vertical, Horizontal, and Sub-vertical Fractures 64
Figure 43 Schematic Design of a Multilateral Cluster Well 67
Figure 44 A Microhole Drilling Rig on Location 69
Figure 45 GTI Laser Laboratory 71
Figure 46 Sand Grains Before Lasing 71
Figure 47 Sand Grains After Lasing 72
Figure 48 Examples of Perforation Tunnels Using Collimated and Focused Beams 73
Figure 49 Perforation Tunnel in Limestone Using the Variable Focal Length Technique 73
Figure 50 Schematic Diagram of Optical Setup for Collimated and Focused Beams 74
Figure 51 Photograph of a Sectioned Block After Lasing (A) and 2-D and 3-D Permeability Contour Maps (B and C) Prepared from Measurements on the Backside of the Block 74
Figure 52 ANG Process 80
Figure 53 Examples of ANG Storage Capacity 81
Figure 54 Schematic of Typical ANG System 85
Figure 55 Prometheus Commercial LNG from Landfill Gas Facility 96
Figure 56 Operating Scenario 1 Process Flow Diagram 99
Figure 57 Operating Scenario 2 Process Flow Diagram 100
Figure 58 Northstar Industries City Gate LNG Plant 102
Figure 59 CNG Land Based Vertical Storage System Rendering (1) 103
Figure 60 CNG Land Based Horizontal Storage System Rendering (2) 104
Figure 61 CNG Pressure/Temperature Optimization 105
Figure 62 CNG Storage Cylinder 106
Figure 63 Gas Containment System 106
Figure 64 CNG Storage System Configuration 107
Figure 65 CNG Storage Process Schematic 108
Figure 66 Density as % of LNG 117

Figure 67 Various Storage Option Densities ... 118
Figure 68 Methane Hydrate Phase Equilibrium Diagram ... 132
Figure 69 Photographs of NGH pellets produced by Mitsui Engineering ... 133
Figure 70 NGH Production Pilot Unit at Chiba, Japan ... 133
Figure 71 Rock Cavern Under Construction at Skallen, Sweden ... 136
Figure 72 Modeling Approach for Evaluation of LRC Sites ... 138
Figure 73 GTI Facility Test Station ... 217
Figure 74 VOTRANS Maritime Work Program Schedule ... 220

Table of Tables

Table 1 Section 3.0 Objectives and Actions 7
Table 2 Section 4.0 Objectives and Actions 8
Table 3 Section 5.0 Objectives and Actions 8
Table 4 Key Reference Research........ 12
Table 5 PG&E Peak Day Demand/Supply........ 31
Table 6 North Region Peak Day Demand Forecast 31
Table 7 SoCalGas Peak Day Demand/Supply 45
Table 8 SoCalGas Peak Day Demand Forecast 46
Table 9 Statewide Peak Day Demand Analysis 49
Table 10 Conventional Gas Storage Enhancement Technology Summary 77
Table 11 Estimated Unit Storage Capacities for ANG System 82
Table 12 Estimate Number of Cylinders for Operating Scenarios 1&2 @ 850 psig 83
Table 13 CAPEX Estimation for ANG Storage System (Commercial-grade Carbon) 87
Table 14 CAPEX Estimation for ANG Storage System (High-performance Carbon) 87
Table 15 OPEX Estimation for ANG Storage System 88
Table 16 Estimated Annual Carbon Unloading and Re-loading Costs [d]........ 88
Table 17 CAPEX and OPEX Summary 93
Table 18 Conversion Energy Requirements........ 94
Table 19 Summary of Candidate Liquefaction Cycles for LNG Plants 94
Table 20 Typical LNG Peak Shaving Specifications........ 97
Table 21 Small Scale LNG Operating Specifications 97
Table 22 Operating Scenario 1&2 Parameter........ 98
Table 23 Liquefaction Rate Parameters 98
Table 24 LNG Comparison Summary........ 98
Table 25 Comparative LNG Project Costs........ 101
Table 26 Small Scale LNG Capital Cost Estimate........ 101
Table 27 Typical LNG Peak Shaving Plant Parameters 102
Table 28 Vertical Storage Facility Dimensions*........ 109
Table 29 Operating Scenario 1&2 Assumptions........ 111
Table 30 OS1 Operating Parameters 111
Table 31 OS 2 Operating Parameters 112
Table 32 CAPEX and OPEX Cost Estimates 113

Table 33 Density-Range For Pipeline-Quality Natural Gas 115
Table 34 Operating Scenario Cost Summary 129
Table 35 Minimum Required Cavity Volume for Given Withdrawal Rates 139
Table 36 Federal and State Regulations That are or may be Applicable to the LRC Technology in Massachusetts (Section 1 of 5) 160
Table 37 HHI based on CA storage field working gas capacity 172
Table 38 HHI based CA Storage Field Withdrawal Deliverability 172
Table 39 HHI based on CA storage field *noncore only* working gas capacity 173
Table 40 HHI based on non-core only Deliverability 175
Table 41 California Pipeline and Storage Deliverability 176
Table 42 NR Historical Data 182
Table 43 NR Monthly Forecast Data 187
Table 44 NR Annual Forecast – Average Demand Year 196
Table 45 NR Annual Forecast – High Demand Year 198
Table 46 SR Historical Raw Data 200
Table 47 SR Monthly Forecast Data – Average Temperature Year 206
Table 48 SR Annual Forecast Data – Cold Temperature Year 215

Abstract

The objective of the research and analysis contained within this report was to identify and assess new and alternative natural gas storage technologies and to determine how they can best be utilized to provide safe, reliable, and cost effective natural gas to California consumers into the foreseeable future. Natural gas consumer demand forecasts provided by California operating utilities, Southern California Gas Company and Pacific Gas and Electric, are analyzed and illustrated within. The analysis indicated that although natural gas demand is expected to continue growing in both Northern and Southern regions of California, natural gas supply from a transmission pipeline capacity perspective on an aggregate, statewide basis is expected to remain adequate (approximately 30% reserve margins in peak day demand scenarios) over the forecast period. A critical assumption behind this statement is that other state's natural gas demand and other potential commodity shortages will allow for adequate natural gas to reach California transmission and distribution networks in peak demand conditions.

Also investigated were potential peak day demand solutions to supplement local infrastructure capacity as well as deliverability enhancements to traditional underground gas storage assets. Identified was several point source, or "dispersed energy", alternative gas storage technologies designed to provide incremental and supplemental natural gas to consumers in peak demand operating scenarios. These technologies, each in various stages of development and commercialization, were investigated for operational and economic feasibility. Results indicated potential alternatives to costly traditional local infrastructure enhancements that may be able to provide operational flexibility at competitive costs while satisfying forecasted peak day demand system requirements.

Finally, the report also focused on identifying and reviewing any potential regulatory barriers to implementing new technologies investigated as well as expansion of valuable traditional gas storage assets. No major regulatory barriers were identified for the alternative gas storage technologies described above. However, it was recommended that a broader market definition approach be taken to the market power HHI index to include not only storage deliverability but also deliverability from California natural gas pipelines and instate wells to promote the expansion of traditional underground storage assets.

Keywords: natural gas, underground natural gas storage, liquefied natural gas LNG, adsorbed natural gas ANG, compressed natural gas CNG, cold compressed natural gas CCNG, supply, demand, infrastructure, dispersed storage, HHI, natural gas hydrate storage NGH, lined rock cavern LRC, pipeline, demand forecast, hydraulic fracturing, laser drilling, market power, deliverability, trending.

1.0 Executive Summary

The Gas Technology Institute (GTI), working in collaboration with project partners Southern California Gas Company (SoCalGas) and Pacific Gas and Electric Company (PG&E), performed research on issues surrounding California's utilization of underground natural gas storage. Three essential tasks were identified in this research effort. Each of these tasks is addressed in the report and organized into three individual chapters. The project's primary focus is to identify potential natural gas storage technologies and to determine how they can best be utilized to provide long term safe, reliable, and cost effective natural gas to California consumers.

Analysis regarding demand fluctuations and trending were based on both historical usage data and forecasted demand data supplied by participating utilities SoCalGas representing the southern portion of the State and PG&E representing the northern and central portion. SoCalGas and PG&E combined deliver and service approximately 80% of California's consumer demand for natural gas. To provide a baseline of usage, five years of historical consumer usage data (2002-2007) were requested and collected from the utilities. Historical data submitted included hourly, daily, seasonal, and annual data. The second component of historical data collected focused on underground natural gas storage utilization over the same period (2002-2007). Forecasted demand data were collected through year 2025 from each of the participating investor-owned utilities. Analysis indicates a steady but very moderate average annual growth rate of .6 percent statewide (1.3 percent average annual growth in the PG&E region, .14 percent average annual growth in the SoCalGas region) in natural gas demand over the forecast period. Market segments such as electrical generation, commercial, and residential use showed increased demand but were tempered by decreased projected demand in the industrial and other market segments.

Seasonal and daily (hourly) trends were illustrated using historical data as a base reference and extrapolated to adjust for supplied base case forecasted volumes. A significant variable in establishing seasonal trends is weather and therefore these trends are expected to remain relatively consistent over the forecast period as corroborated by extensive historical data. Hourly forecasts were calculated using a percent volume base per hour. In a relatively more conservative scenario supplied by SoCalGas (1-in-10 event), hourly forecasted trends indicate nearly 1,100 MMcf of natural gas deliveries will be required on its system over the course of just 4 hours (6am – 10am). PG&E's system forecast indicates a requirement of approximately 870 MMcf over a similar four hour period (8am – Noon).

Peak day demand scenarios outlined in Section 3.0 are based on historically calculated ratios, extrapolated to reflect forecasted values. Both average demand (temperature, hydro conditions) and high demand scenarios (low temperature, low hydro conditions) are included in the analysis for the forecast year 2025. The analysis indicates a statewide peak day demand requirement of approximately 11,500 MMcf. Subsequent review and analysis of interstate pipeline and gas storage capacities available to satisfy daily requirements in adverse conditions indicate capacities of approximately 15,500 MMcf. Given this analysis, there appears to be adequate infrastructure available to meet forecasted demand over a forecast period of approximately 15 years.

PG&E and SoCalGas operate key underground natural gas storage facilities. Utilization analysis indicates these facilities typically meet a third of the average daily statewide natural gas demand and up to 60% of total system demand in peak day demand scenarios. Given the seasonal nature of consumer demand established and supported within the report, it is not expected for traditional underground gas storage utilization to significantly change in the two utility service areas over the forecast period reviewed.

Trending and peak day analysis provided insight into expected natural gas load on local infrastructure (transmission and distribution systems). Though total statewide theoretical capacity in the supply portfolio (pipeline and storage) appears adequate, whether the local utility can deliver those volumes is uncertain. This statement is based on discussions with SoCalGas and PG&E, as each operating utility expressed concern whether consumer demand and deliverability can be met under conditions experienced in peak day events. Each utility has experienced curtailments within its transmission and distribution systems under certain extreme conditions. Detailed analysis of local infrastructure was not performed within this research effort.

Uncertainties inherent in natural gas demand -- especially with the high probability that greenhouse gas (GHG) legislation will be implemented nationwide within the next few years and the resulting near-term increase in demand for natural gas for power generation -- make it prudent the California and the CEC examine and have ready options for natural gas storage in the event of unanticipated spikes in natural gas demand, especially for seasonal, hourly, and local needs.

Thus the Section 3.0specific recommendations resulting from the trending and peak day analyses are that California should:

- Further investigate the ability of local infrastructure to provide natural gas in sufficient volumes to satisfy customer demand over the forecast period, particularly deliverability of local transmission and distribution systems to supply up to 1.1 Bcf of natural gas in a four-hour window in SoCalGas territory, as well as nearly 900 MMcf in PG&E's service territory.
- Consider developing or enhancing gas storage facilities for both increased reliability and deliverability in meeting growing consumer demand as well as ensuring delivery of cost-effective natural gas to the customer meter.

With these results and recommendations in mind, the objective of the alternative technologies research described in Sections 4.0 and 5.0 was to explore California's natural gas storage deliverability options with consideration placed on potential local infrastructure capacity limitations. Also reviewed was how underground or alternative natural gas storage can be utilized more effectively or enhanced to provide cost effective service to California consumers. Improvements in traditional deliverability enhancement technologies are investigated, with review and analysis of hydraulic fracturing, advanced drilling techniques, and laser based completion and stimulation applications included in the report. Alternative (non-traditional) gas storage technologies emerging in the industry are reviewed for applicability and feasibility. Technologies included new "dispersed storage" (individual or "mobile" assets) applications of small-scale liquefied natural gas (LNG) and compressed natural gas (CNG), as well as emerging gas storage technologies involving the use of natural gas hydrates, cold compressed natural gas storage, adsorbed natural gas, and lined rock caverns (LRC). Operational and brief economic reviews based on three operating scenarios provided by SoCalGas and PG&E are performed to determine application feasibility of each technology reviewed. Descriptions of all technologies can be found in Section 4.0

Alternative and conventional natural gas storage technology assessment recommendations are:

- Field testing of enhancements to conventional underground storage, such as hydraulic fracturing and directional drilling, to quantify the increased deliverability potential and resulting economic advantages.
- Field testing and demonstration of cold compressed natural gas (CCNG) storage and pipeline systems in California to mitigate a local infrastructure bottleneck, test performance of some aspects of the CCNG technology, and to navigate the certification and permitting issues associated with the deployment of a new type of pipeline. This will also allow validation of the postulation of superiority of CCNG over CNG and adsorbed natural gas (ANG) in terms of deliverability, energy density, and lower cost.
- Additional pilot scale laboratory testing of gas hydrate systems and surfactants to confirm that this technology can in fact store and readily disassociate natural gas.
- Perform additional basic and applied research on ANG to develop new matrix materials to increase energy density to more than 300 volumes per volume, as well as ascertain whether these materials present toxicity issues. No field testing of this technology is recommended at this time, unless the technology advances enough to change its economic potential.
- R&D on LRC storage is not required at this time due to its lack of economic potential. A geological study should be performed prior to additional research to determine applicability in California.
- Small-scale LNG facilities (thousands to tens of thousands of gallons per day) have been in use in California and other states for fueling natural gas vehicles (NGVs). No further demonstration of these systems is needed. (Favorable regulatory review by California Air Resources Board (CARB) and other agencies have occurred due to the environmental benefits of natural gas as an alternative vehicle fuel.)
- However, medium-scale (tens to hundreds of thousands of gallons per day) LNG facilities need to be demonstrated in California to validate its economic viability and deliverability.
- No R&D is needed for CNG storage. This technology is mature and has seen extensive use for NGVs. Field demonstrations are recommended for this technology.

Relevant regulatory policies and practices were reviewed and analyzed, and where appropriate, changes proposed that would encourage expansion and enhancement of traditional natural gas storage services in California. The research also identifies concerns and promotes ways to implement the alternative gas storage technologies researched.

Recommendations are made as to potential solutions to ease regulatory approval, without compromising environmental, safety, market concentration, and other relevant concerns. These recommendations include:

- Adoption of a broader "market" definition for gas storage market-based rate determinations, including storage, pipeline, and in-state well deliverability.
- The CPUC could determine that market-based rates for new independent storage projects are just and reasonable because customers are better off than they would be if the project was not built.
- An increase in storage capacity and storage deliverability requirements for core customer storage.
- Allowing expedited siting for onshore LNG peak shaving plants. The use of a "lead agency" concept that coordinates reviews for all agencies was encouraged.
- A thorough investigation should be conducted into the use of potentially hazardous materials for alternative storage options, particularly ANG and gas hydrates.
- Regulatory procedures for expediting consideration of CCNG should be developed so that CCNG will not have to undergo both cryogenic and high-pressure regulatory investigations in series.
- A cost-based rate option for encouraging investment in underground storage could be accomplished through adjustments to the cost of service.
- Revision of or waive the Federal Energy Regulatory Commission (FERC) policies on environmental and other reviews

Finally, it was noted that in recent FERC and California Public Utilities Commission (CPUC) decisions, that both organizations recognized that enhanced market-based storage capacity and deliverability -- especially by independent operators -- was of such benefit to gas consumers that it generally outweighed considerations of market power.

2.0 Introduction

2.1. Background and Overview

The PIER Natural Gas (PIERNG) program covers several areas such as environmental impacts, efficient use of gas, and renewable substitutes for natural gas. One of these research areas focuses on having an integrated natural gas system that is reliable and secure. For this area, there are six strategic objectives:

- Develop natural gas storage technologies.
- Improve safety and security of natural gas production, storage, delivery, and use. . Develop innovative tools, methods, and models to improve efficiency of natural gas markets.
- Reduce peaks for improved asset utilization.
- Understand and address impacts of LNG on natural gas infrastructure and related interchangeability issues.
- Develop knowledge base for future decision-making and informed delivery, integration, and infrastructure policy relative to natural gas.

The natural gas storage research effort specifically addresses issues defined by the Integrated Energy Policy Report (IEPR) and the Governor with respect to the need for storage to help provide adequate supply and protect prices. This effort has been undertaken with the understanding that the recent dramatic expansion of gas-fired generation has significantly increased natural gas consumption and contributed to tighter demand conditions year round and increases in natural gas price volatility. It is expected that by expanding and/or better utilizing in-state natural gas storage infrastructure, California's consumers will enjoy reduced gas costs, less price volatility, and greater reliability of supply.

In response to a Research Opportunity Notice focused on addressing the PIERNG goals, Gas Technology Institute developed a project that involves defining California natural gas demand trends, collecting supply data, analyzing existing infrastructure, reviewing relevant California energy policy, and analyzing existing and emerging natural gas storage technologies. This research provides information that answers questions inherent to California's ability to meet future environmental and public needs, in an efficient and effective manner, as well as market demand. Questions addressed include:

- Is the market demand inherently changing and what is the potential impact on natural gas storage?
- What are the potential barriers to enhancing the economic and physical benefits of natural gas storage in California?
- What are alternative gas storage technologies role and how could they supplement and complement existing natural gas storage infrastructure?

The research also includes investigation and analysis of the market power threshold test referenced by state and federal regulators in order to assess its impact on potential gas storage expansion by independent operators.

GTI conducted broad and comprehensive natural gas storage and alternative gas storage market research in partnership with Southern California Gas Company and Pacific Gas and Electric. The work plan included three major tasks, which correspond to Sections 3.0, 4.0, and 5.0 in this report.

2.2. Project Objectives/Report Organization

As indicated in the background section above, this research effort had three related yet distinct objectives. The first objective (researched in Section 3.0) was to define how the market demand has changed over time and extrapolate for future trending. Results from data collected helped direct research efforts in selecting and assessing traditional and alternative gas storage technologies (Section 4.0).

Table 1 Section 3.0 Objectives and Actions

Section 3.0: Define California Market Demand Fluctuations and Trending
• Collect consumer usage data from collaborating partners Southern California Gas Company(SoCalGas) and Pacific Gas and Electric (PG&E), This data will verify and provide historical baselines and trends in consumer usage over the past 5 years, and provides a foundation for future consumer usage trending. Forecasting data will also be collected from collaborating partners to provide a basis for future trending.
• Research other sources of indirect trending data collected by agencies such as California Public Utilities Commission (CPUC), Energy Commission, American Gas Association (AGA), Gas Research Institute (GRI), Pipeline Research Council International (PRCI), Gas Storage Technology Consortium (GSTC), etc…Information will also be collected with a focus on infrastructure, economy, and legislation affecting demand forecasts.
• Review, interpret, and analyze collected data with a focus on investigating gas storage utilization, identifying areas of concern, and potential infrastructure limitations.
• Establish current demand fluctuations, and formulate future consumer demand and usage trends within the state of California.

Objectives of Section 4.0 research focused on identifying and analyzing gas storage deliverability and capacity options. Improved deliverability of existing gas storage fields through traditional remediation techniques are analyzed for applicability. Alternative (non-traditional) gas storage technologies emerging in the industry are also reviewed for applicability and feasibility. Technologies included new small scale applications of LNG while other dispersed storage (individual or "mobile" assets) involve the use of natural gas hydrates, both in situ and surface applications, as well as CCNG. Economic considerations, where appropriate, are evaluated to determine feasibility of each technology reviewed. Technologies include review of traditional deliverability options for existing gas storage fields as well as alternative natural gas storage technologies organized into the following sections:

- Background/Technology Description
- Operational Feasibility
- Economic Feasibility
- Commercialization Status

Table 2 Section 4.0 Objectives and Actions

Section 4.0: Define Natural Gas Storage Deliverability Options
• Research technologies which supplement or complement existing California natural gas supply infrastructure. • Research and identify conventional underground storage deliverability enhancement technologies. • Research and determine operational and economic feasibility of emerging alternative natural gas storage technologies.

Objectives researched in Section 5.0 are to review and analyze relevant regulatory policy and practice, and, where appropriate, propose changes that would encourage expansion and enhancement of natural gas storage services in California. Specifically, with technologies identified in Section 4.0 firmly in mind, this review will identify storage options that might be discouraged by regulation and propose means of bringing such regulation into line with the goal of promoting expansion and enhancement of gas storage services to benefit California's gas consumers. Methodologies utilized to calculate and determine market power are reviewed and analyzed for relevancy in today's market and that it accurately reflects market conditions moving forward. Alternative options in policy and methodologies are provided that inherently promotes natural gas storage infrastructure enhancements and expansion.

Table 3 Section 5.0 Objectives and Actions

Section 5.0: Regulatory/Policy Review
• Review and analyze relevant regulatory policy and practice. • Review California regulatory policy on integrating alternative gas storage technologies into California infrastructure. • Identify Section 4.0 recommendations that are or may be discouraged by federal or state policy. • Determine options for altering national and California policy and practice to promote expansion and enhancement of gas storage infrastructure.

3.0 Define California Market Demand Fluctuations and Trending

3.1. Project Approach

Data Collection

The foundation of this analysis is based on both historical usage data and forecasted demand data supplied by participating utilities Southern California Gas Company (SoCalGas), representing the South Region, and Pacific Gas and Electric Company (PG&E), representing the North Region. SoCalGas and PG&E combined deliver and service approximately 80% of California's consumer demand for natural gas. To provide a baseline of usage, five years of historical consumer usage data (2002-2007) were requested and collected from the utilities. Historical data submitted included hourly, daily, seasonal, and annual based data. The second component of historical data collected focused on underground natural gas storage utilization over the same period (2002-2007). Forecasted demand data were collected through year 2025 from each of the participating operating utilities. Two sets of forecasted data were supplied, with a single base case scenario providing the foundation. The first set depicted an average temperature year for each region while the second reflected a colder than average temperature year. This was due to the fact that seasonal temperature variations cause significant changes in winter gas demand for space heating in the residential and core commercial and industrial sectors. A second factor impacting demand variations, particularly in the north region of California, is hydro conditions. The variability of annual runoff for hydroelectric generation is significant and the impact of drought conditions is taken into consideration in the high demand scenario. Forecasting methods for north and south regions are further detailed in the project outcomes section of this report.

Historical consumer usage data for both the north and south regions of California were submitted in aggregate format defined by core and non-core usage. North region included off-system deliveries outside their service territory, while south region included wholesale and international deliveries.

Historical gas storage data included injection and withdrawal volumes in aggregate format representing utilization for north and south regions. These data were provided on a daily and seasonal basis.

Forecasted demand for each region was further specified by market segment within core and non-core usage. The data stream is organized into the following core and non-core market segments for the north and south regions of California.

North Region

Core

- Residential
- Commercial
- Natural Gas Vehicles

Non-Core

- Industrial (includes Sacramento Municipal Utility District Electrical Generation-SMUD EG)
- Electrical Generation
- Cogeneration
- Wholesale

Off-System Deliveries

Off-System deliveries include natural gas delivered outside of PG&E's service territory.

South Region

Core

- Residential
- Commercial
- Industrial
- Natural Gas Vehicles

Non-Core

- Commercial
- Industrial
- EOR Streaming
- Electrical Generation

Wholesale & International

- Core
- Non-core
- Electrical Generation

Market Segment Definitions

The following market segment definitions reflect the four primary segments addressed in this report.

Residential

Residential market segment natural gas consumption is composed of space heating, water heating, and cooking.

Commercial

Commercial natural gas consumption is based on the energy consumption associated with the commercial facility building type. Commercial establishments have been grouped into the following classifications: small office, large office, restaurant, retail, grocery, warehouse, refrigerated warehouse, school, college, hospital, hotel, agricultural, and miscellaneous. The various commercial establishments will have a different energy use per square foot of floor space.

Industrial

The industrial market segment is typically comprised of core and non-core segments including retail, food, transportation, refinery, chemical, etc.

Electric Generation

The EG segment is comprised of commercial and industrial cogeneration, enhanced oil recovery cogeneration, refinery related cogeneration, and all non-cogeneration electric generation.

Reference Research

A review of past studies conducted by agencies within California, for example the CPUC, as well as national organizations such as the American Gas Association (AGA), Gas Research Institute (GRI), Pipeline Research Council International (PRCI), and the Department of Energy's Gas Storage Technology Consortium was performed to provide a broader perspective and validation for data collected and subsequent analysis. Key components researched where those that directly and indirectly influence consumer demand in California and associated impacts on gas storage utilization. This includes indicators such as natural gas and electrical generation forecasts, energy efficiency forecasts, regulatory policy changes, economic stability, transmission and distribution infrastructure forecasts, and other related information that could be used as a reference for data or directly impact forecasts. In summary, data and forecasts supplied by SoCalGas and PG&E were found to be consistent and reasonable with previous research. Key references utilized in this research are highlighted in the Table 4. A complete list can be found in the appendix.

Table 4 Key Reference Research

	Agency/Institution	Title	Description
1	California Energy Commission	2006 California Gas Report	Natural gas demand and supplies for California forecasted through 2025
2	California Energy Commission	California Energy Demand 2008-2018 - Revised	Revised forecast of electricity, natural gas, and peak demand in California
3	California Energy Commission	2006 Integrated Energy Policy Report Update/2007 Draft	Review of Renewable Portfolio Standard activities and land use planning in California
4	Energy Information Administration	Annual Energy Outlook 2007	Comprehensive national review of energy usage and demand
5	Global Insight	The Impacts of Natural Gas Prices on California Economy	Assessment of impacts of natural gas price volatility on the California economy.
6	California Energy Commission	Revised Natural Gas Market Assessment	Review of California natural gas demand, supply, infrastructure, and price.

Data Analysis

Data utilized for analysis and determining trends and usage variations were supplied directly from SoCalGas and PG&E, with minor variations based on updated reference materials. The purpose of this task is to utilize actual and forecasted data supplied to illustrate trends, seasonal and hourly variations within the data, and gas storage utilization to provide a basis to identify appropriate technologies to enhance California's gas storage and supply portfolio to meet those variations in demand. The data collected and resulting analysis is focused on addressing the following key objectives:

Historical Growth Trends

Historical growth trends in usage, overall and within each particular segment, was established. The purpose of reviewing overall usage and segment trends is to provide validation for forecasting segment growth.

Seasonal Variations

Seasonal variations were defined from a usage perspective. Seasons were individualized by the gas storage cycles as well as by non-core electrical generation to define historical trends and predict potential consumer usage variations that may result in the necessity to alter traditional supply scenarios.

Natural Gas Storage Utilization

Gas storage contributions to overall supply portfolio are established on a seasonal basis. Data collected provided a baseline for natural gas storage utilization in the supply portfolio. The baseline helps to identify potential changes in utilization and operations required to meet future demand and seasonal variations.

Hourly Demand Variations

Hourly usage data by core segments as well as non-core electrical generation are established to determine trend variations. The impact of key growth segments on hourly usage will allow determination for future requirements and help identify potential capacity or supply constraints.

Peak Day Demand Forecast

Peak day demand forecasts were developed for each region to provide a benchmark for system infrastructure planning for California. This information can be used for planning general supply requirements statewide as well as regionally for operating utilities.

Establish Trends and Identify Potential Impact

Historical and forecasted data have been supplied, with the resulting trends defined by seasonal, daily, and hourly usage by market segment. These trends are then used to extrapolate the historical baselines established for each market segment to determine any variations from traditional consumer usage. For example, if significant growth in natural gas fired electrical generation is forecast, what impact might this have on seasonal, daily, and hourly usage? This method is used to determine if infrastructure limitations will be evident in the forecasted future.

Gas storage utilization and requirements are extrapolated under the assumption of providing at a minimum the same price leveraging benefits to California consumers as indicated by five years of historical utilization data. Variations in consumer gas usage identified above are reviewed to determine if traditional gas storage operations will continue to meet expected demand from both a volume and timing perspective.

These scenarios are developed under both average and high temperature forecasts, as well as a peak day scenario. A description of these scenarios is included in the next section - Project Outcomes.

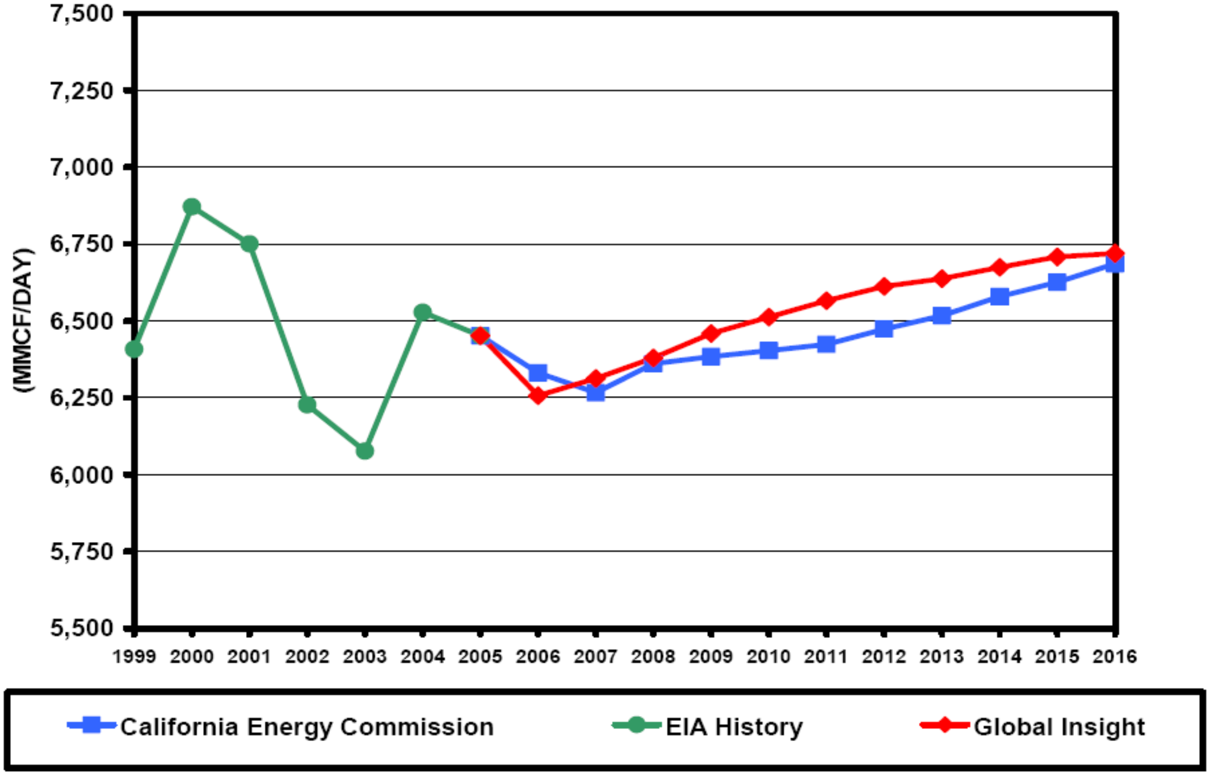
3.2. Project Outcomes

California Natural Gas Demand Summary

Previous research and forecasting completed by the California Energy Commission (CEC), Global Insight (economic and financial consulting), and the Energy Information Administration (EIA) generally agree that total demand for natural gas in California will grow at an annual rate of approximately 0.55% in the forecast period 2006–2025, and at higher average annual rates of 1.76% in the commercial sector and 1.33% in the residential sector. By comparison, average annual demand growth for power generation will be 0.54%, while industrial demand will decline 0.77% annually. These growth rates are similar to those calculated by Global Insight in its forecast, which show a small decline in industrial natural gas demand.

Figure 1 represents comparisons of natural gas demand growth rates prepared by Global Insight, CEC, and the EIA.

Figure 1 California Demand Growth Comparisons



The 2006 California Gas Report, written and submitted by California utilities, project a similar overall natural gas demand annual average rate of 0.5 percent, however residential and commercial segments are considerably lower at 0.4 percent average annual increases with an electrical generation average annual increase at 1.8 percent. Industrial demand forecasts are consistent with a slightly decreasing average annual percentage over the life of the forecast.

The natural gas pricing forecast used to develop demand projections were based on three different time periods and methods. Long term forecasts relied on fundamentals-based models, while the intermediate forecast was a blend of the short and long term forecasts. Industry experts (National Energy Board, Energy Information Association, etc.) project gas prices will remain relatively escalated due to a few key factors. There is general agreement (NEB, EIA) that there has been a step-change in the level of natural gas prices and that the market price reflects a tight balance in North American natural gas supply and demand. In this situation North American natural gas prices are increasingly influenced by the cost of alternative fuels and the rising costs of finding and bringing new gas supply to market. North American gas production is expected to be rather flat, while North American natural gas consumption is projected to continue to grow. As a result, a tight balance between natural gas supply and demand will influence natural gas prices for the remainder of the forecast period. In comparison, California gas prices generally track those in other regions of United States, though at a slightly lower price point (Ex. Henry Hub).

Regulatory programs have been introduced in California influencing demand/supply forecasting. Gas Market Order Instituting Rulemaking (OIR) (R.04-01-025) was issued in 2004 in a two phase approach. It focused on reducing gas demand, ensuring sufficient interstate pipeline capacity, maximized storage utilization, and enable access of LNG imports. Phase 1 addresses acquisition of interstate pipeline capacity, while Phase 2 is designed to address infrastructure adequacy. Details of R.04-01-025 can be found on the CEC website.

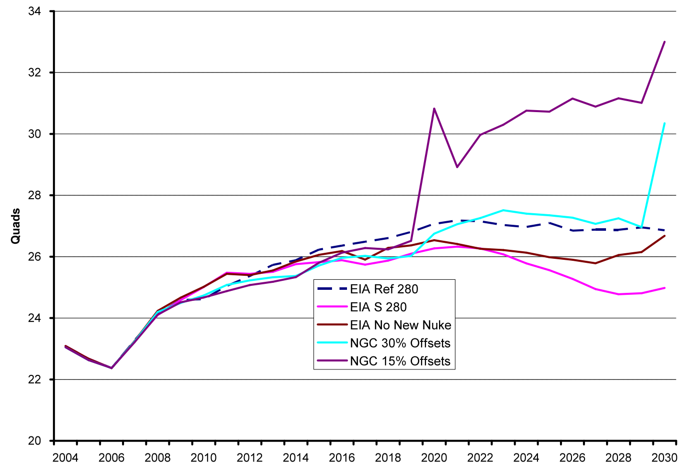
FERC proceedings also affect forecasting, especially those effecting interstate capacity serving California and specifically SoCalGas service territory. Examples of proceedings include those focusing on rate case filings and those surrounding pipeline expansion applications such as North Baja Pipeline. This expansion proposes to import up to 2.7 Bcf/day of re-gasified LNG from Baja California, Mexico.

Recent studies conducted on the impacts of Greenhouse Gas (GHG) legislation show potential variability in forecasting that is not taken into consideration in current models executed and submitted by SoCalGas and PG&E for this report. Joel Bluestein of ICF International presented[1] to GTI's Public Interest Advisory Committee the results of a Natural Gas Council (NGC)-funded study of the impacts of GHG legislation on natural gas use. According to Bluestein, while most analysis of earlier bills and S. 2191 shows declining gas use due to reduced demand and extensive reliance on nuclear, carbon capture on coal, and renewables for power generation, the NGC believed these studies to be overly optimistic in their assumptions on the ease of permitting and building of nuclear power plants and the speed of proof of concept of carbon capture and sequestration (CCS) and combined cycle gasification (CCG) coal plants.

NGC analysis of earlier GHG bills and some current analysis with more conservative technology assumptions (including restricting the early entry of nuclear power plants and CCG with CCS) show significantly higher gas consumption in 2015 to 2025, on the order of 1 to 3 Tcf higher than the baseline cases (see below). This indicates an increase of natural gas demand required for power generation by nearly 50% over the last 10 years of the forecast.

[1] Bluestein, Joel, ICF Presentation to GTI Public Interest Advisory Committee, April 14, 2008

Natural Gas Council Modeling of Gas Consumption Under S. 280



31

Passion. **Expertise. Results.**

Forecasts by region, North and South, can be found in the following section.

NORTHERN CALIFORNIA REGION

Historical Data

Approximately five years of historical data were collected to provide a trending baseline for two primary objectives. The first objective was to validate market segment forecasting data submitted by PG&E, and identify trends that may indicate variations in consumer usage data that are not readily apparent in the forecasts. Forecasted data was used in conjunction with historical trends to determine variations in seasonal, daily, and hourly demand while highlighting any potential infrastructure limitations.

The second objective was to identify historic gas storage utilization strategies used to meet consumer demand and provide natural gas price leveraging capabilities to those consumers. Utilization data was then extrapolated to meet future demand and determine storage requirements.

Due to the voluminous nature of historical data, they are summarized by market segment in this section of the report. Raw data can be viewed in the Appendix.

Forecast Data

PG&E average year demand forecast projects growth from 2,166 MMcf/day (2007 total end use) to 2,638 MMcf/day in 2025. This equates to an average annual growth rate of approximately 1.3 percent during the forecast period. This is a result of slight growth in the residential and commercial segments, a slight decrease in the industrial segment, and modest growth in the electrical generation segment. A summary of each segment is provided below.

PG&E utilizes econometric forecasting models for the residential, commercial, and industrial sectors, and publicly available market information for non-core sectors such and natural gas vehicles and wholesale. Electrical generation demand is performed by utilizing MarketBuilder (software by Altos Management Partners Inc.) to model the electricity market in the Western Electricity Coordinating Council. Assumptions and variables in the model include weather considerations (average of past 20 years observed temperatures), economic, demographic, and technological changes, price forecasts, efficiency profiles and programs, and growth in electrical generation by renewables. Pricing forecast variables are taken from the Integrated Energy Policy Reports (2006 Update).

The high demand forecast supplied by PG&E was based on a weather vintage approach. Essentially, similar demographic assumptions were made as those in the average year demand forecast, with the exception of weather conditions. High demand forecasts set the weather variable to match the worst seasonal conditions recorded in the past 35 years.

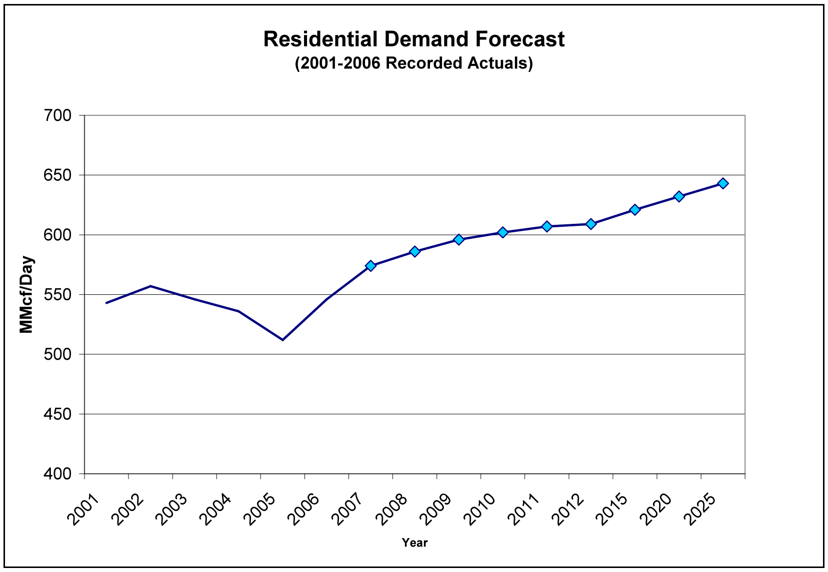
Forecast data are included in the Section 3.0 Appendix.

Market Sectors

Residential

Based on forecasting data, residential demand in the PG&E service area is forecasted to grow at approximately 0.9 percent annually from an actual 2006 value of 546 MMcf/d to projected consumption of 643 MMcf/d in 2025. The forecast is illustrated in **Figure 2.** This value is derived from an overall projected increase of 1.3 percent in households coupled with an annual decrease in gas use per household of nearly 0.4 percent. This is a direct reflection of energy efficiency programs and resulting appliance and insulation efficiencies, as well as less consumer usage due to increasing cost of natural gas.

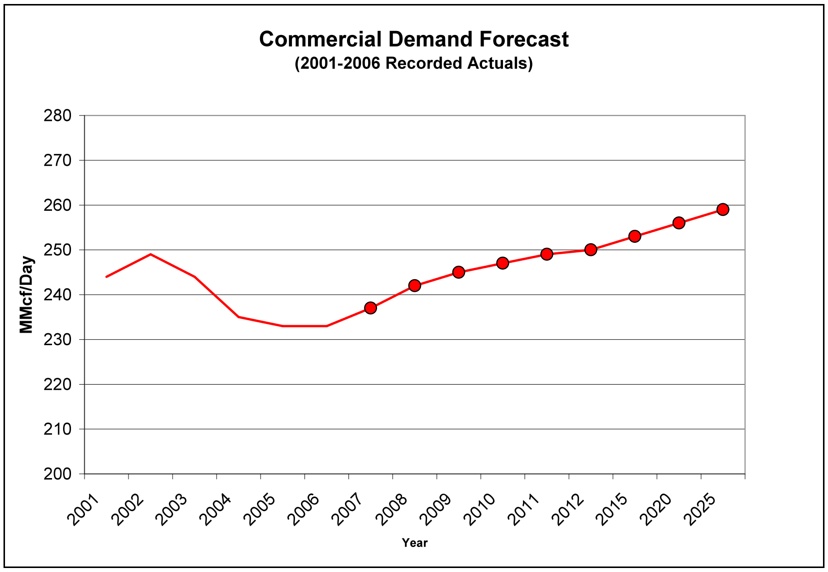
Figure 2 NR Residential Demand Forecast



Commercial

PG&E commercial demand forecast indicates growth from 233 MMcf/d (recorded 2006) to 259 MMcf/d in 2025. This equates to an average annual growth rate of just over 0.6 percent. This growth is tempered by the impact of aggressive CPUC authorized energy efficiency programs in this market segment. Projections assume a flat gas use per commercial customer over the forecast, so the growth rate generally reflects the growth rate of the customer base. The forecast is illustrated in Figure 3.

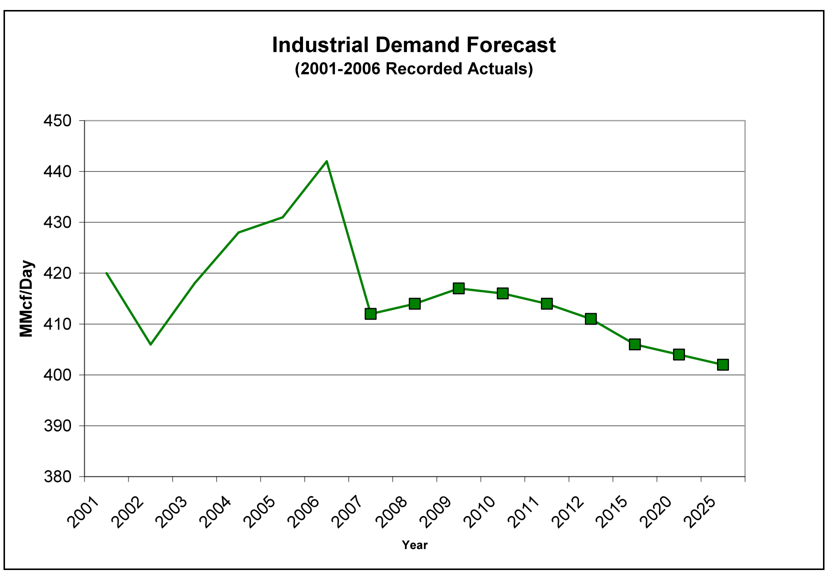
Figure 3 NR Commercial Demand Forecast



Industrial

Industrial gas consumption is expected to decline over the forecasted period by approximately 0.4 percent from a recorded 2006 value of 442 MMcf/d to 402 MMcf/d in 2025. The forecast is illustrated in Figure 4**.** This is generally the result of a decline in California's manufacturing sector as industry gradually changes to service based rather than a manufacturing based.

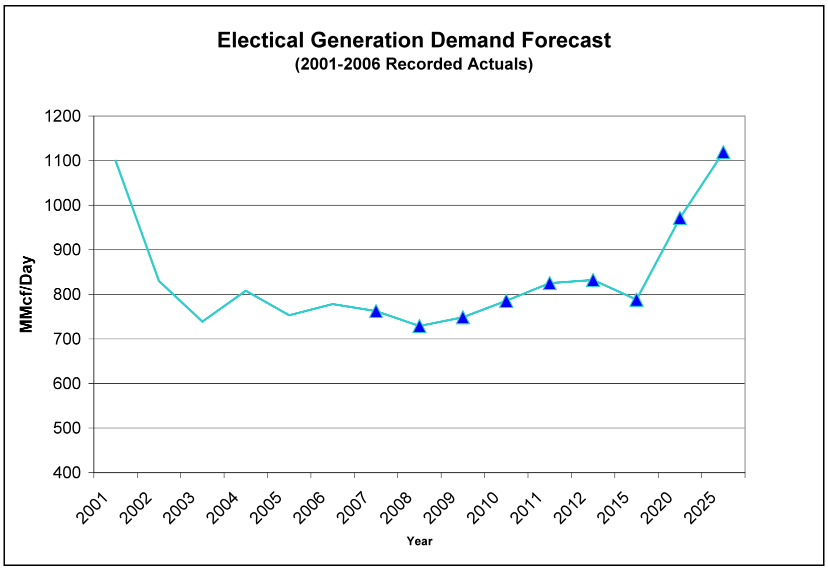
Figure 4 NR Industrial Demand Forecast



Electrical Generation

As indicated above, electrical generation is forecasted using MarketBuilder to simulate the electricity market in the Western Electricity Coordinating Council, and uses the base case electricity demand forecast from the CEC 2005 Integrated Energy Policy Report. PG&E forecasts a growth in demand from a recorded 2006 volume of 778 MMcf/d to 1119 MMcf/d in 2025, or approximately a 2.3 percent annual average increase. The forecast is illustrated in **Figure 5**. Also included in this forecast is Sacramento Municipal Utility District's (SMUD) electrical generation demand. SMUD is the sixth largest community owned municipal utility in the United States and serves over 550,000 customers.

Figure 5 NR Electrical Generation Demand Forecast



North Region Natural Gas Demand Trends

Historical Growth Trends

Historical data were gathered and are illustrated to provide insight into demand trends for each potential market segment identified in the data. PG&E supplied historic data included Core (residential and commercial combined), and Non-Core (Industrial, Electrical Generation, Cogen) with electrical generation and cogeneration further segmented from Non-Core data. Trends for each segment illustrated was calculated by averaging usage from 5 years of historical data supplied (2002-2006), and extrapolated to reflect forecasted demand values calculated by PG&E's forecast model. Industrial demand is forecasted to decline slightly over the forecast period and therefore is not illustrated in this section.

Core Segment

Collected core data for the north region were aggregated to combine both residential and commercial data. For purposes of forecasting, the resulting trends are also aggregated. The following figure illustrates residential and commercial data.

Figure 6 NR Historic Core Usage Trend

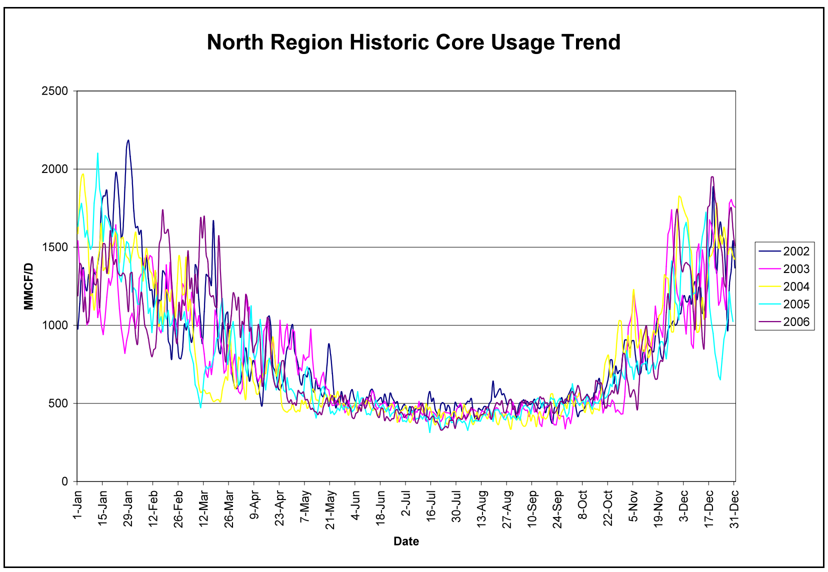
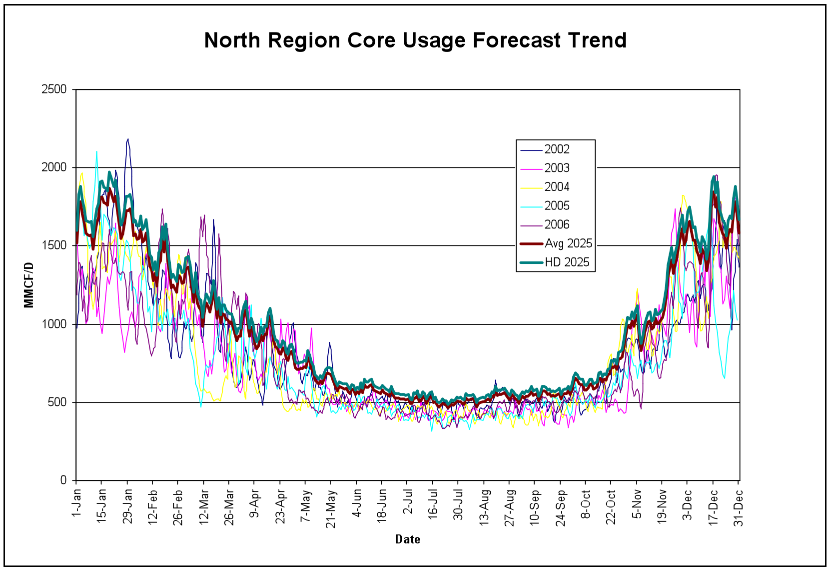


Figure 7 NR Core Usage Trend Forecast



Non Core - Electrical Generation Segment

Electrical Generation illustrated in the following graphs (as EG) includes PG&E cogeneration, PG&E owned electric generation, other non-utility generation, and SMUD generation.

Figure 8 NR Historic EG Trend

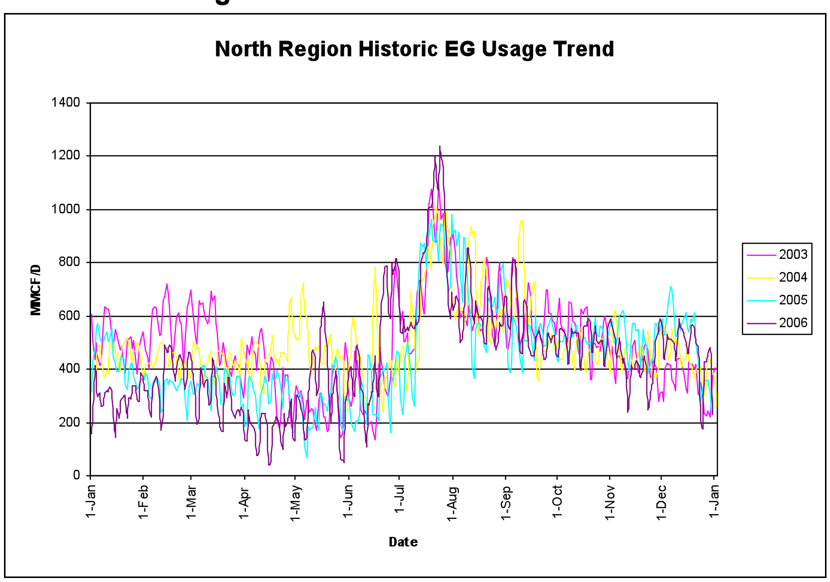
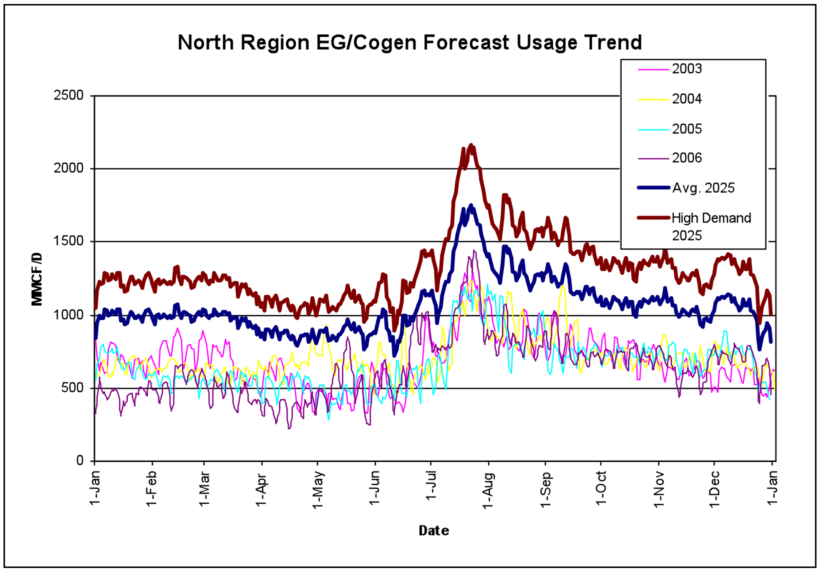


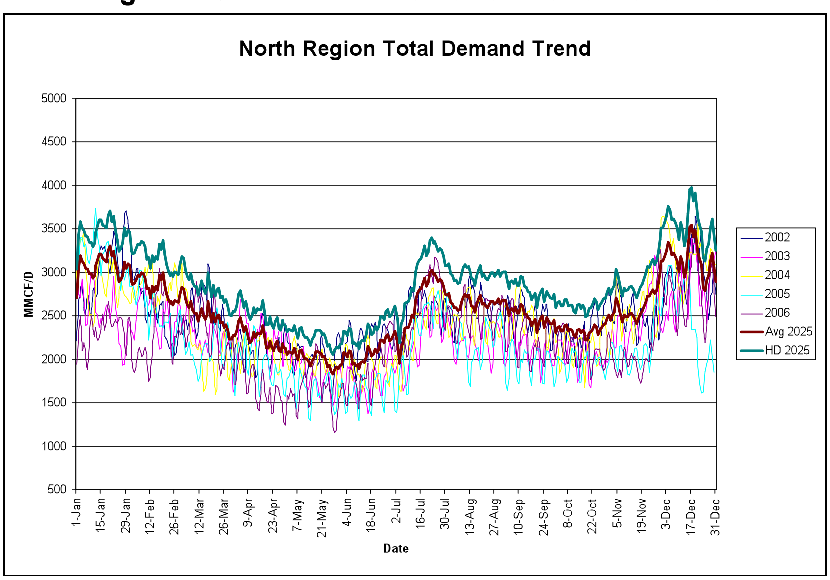
Figure 9 NR EG/Cogen Demand Trend Forecast



Total North Region Demand

The following graph reflects total system demand forecasted trend to 2025 for both average demand forecasts as well as high demand forecasts.

Figure 10 NR Total Demand Trend Forecast



Seasonal Variations

The forecasted trending illustrated in the previous graphs provides a foundation for determining seasonal variations within each key segment. Core, Non-Core (specifically electrical generation), and total north region demand all display very consistent, cyclic usage over the course of a calendar year. Though five years of historical data are analyzed for the purpose of this study, consumer usage patterns in each segment have been very consistent over a much longer period of time, according to previous research and data. This is both logical and expected as the two primary seasonal variation drivers, Core (Residential) and electrical generation consumers, are heavily dependent on temperature for heating and cooling purposes. These seasonal trends are expected to remain consistent throughout the forecast period and are reflected in the figures above.

Natural Gas Storage Utilization

Gas storage contributions to overall supply portfolio are critical and provide two primary benefits. The first is to supplement and augment pipeline deliveries and provide a reliable source of natural gas to consumers in both a seasonal and peak demand capacity. A second, related benefit is the ability to utilize storage to capture arbitrage opportunities by purchasing and storing traditionally lower cost gas in the summer and delivering it during the peak heating season. This provides price volatility protection and ultimately benefits consumers with a lower average natural gas cost relative to pipeline delivery costs for the same period. The following histograms (Figures 11-14) reflect gas storage utilization in PG&E's service territory over the past 5 years. Represented is gas storage contribution as a percentage of overall system sendout to consumers. PG&E gas storage assets account for nearly 20% of the average daily system sendout and up to 40%+ on peak demand days.

Figure 11 NR 2002/2003 Gas Storage Utilization

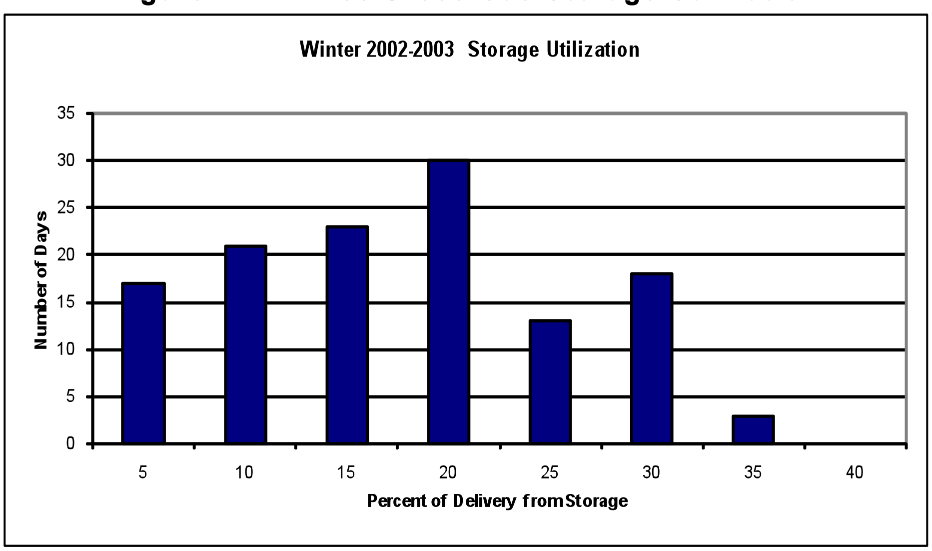


Figure 12 NR 2003/2004 Gas Storage Utilization

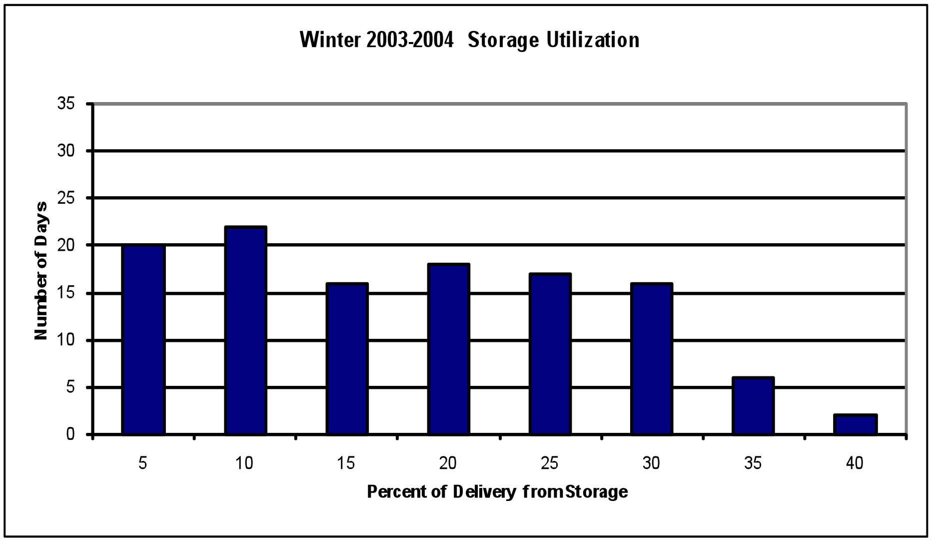


Figure 13 NR 2004/2005 Gas Storage Utilization

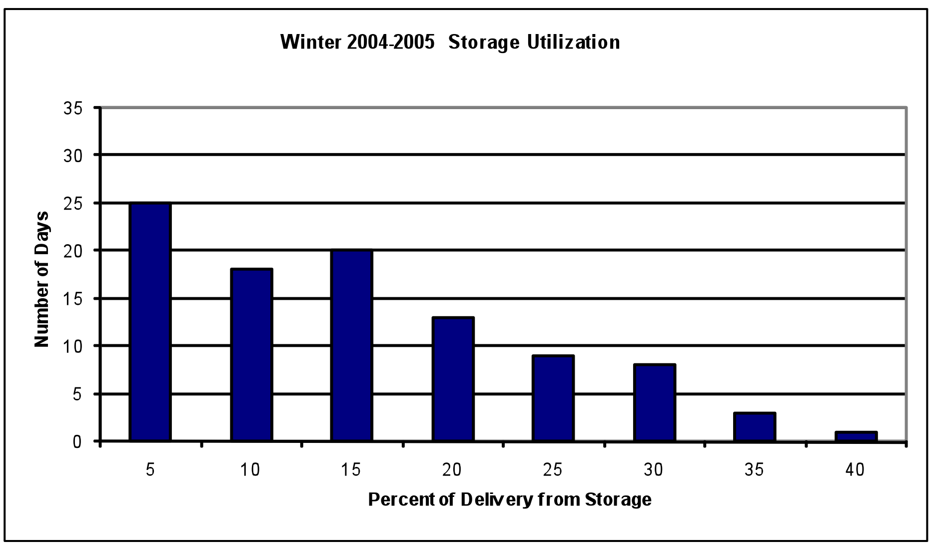
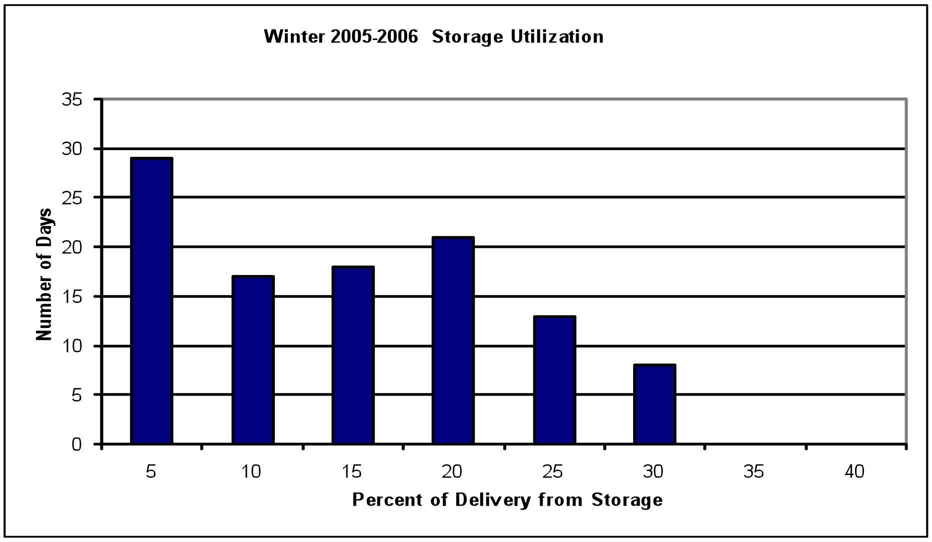


Figure 14 NR 2005/2006 Gas Storage Utilization



Hourly Demand Variations

Hourly data were supplied by PG&E to enable GTI to provide hourly trending analysis. PG&E does not typically capture and record this data on a continual basis or by segment. For the purposes of this study, two scenarios were selected for data capture. Figure 15 illustrates a percentage of total system sendout by hour of the day during a relatively low electrical generation (April) demand scenario. Figure 16 reflects similar data on a high electrical generation demand day (July). These scenarios were chosen as they illustrate the significance of electrical generation demand, which is the key variable in daily and hourly load demand variations.

Figure 17 looks at the contribution of electrical generation on a high electrical generation demand day to the total system sendout. As shown in the figure, an average of nearly 30% of total sendout is consumed by electrical generation facilities in PG&Es system. GTI acknowledges the hourly trends illustrated in the following figures reflect only snapshots in time and are not based on continuous hourly data. It should also be noted the data were total system sendout further segmented only by electrical generation usage.

Figure 15 NR Hourly Trend – Low EG Demand Day

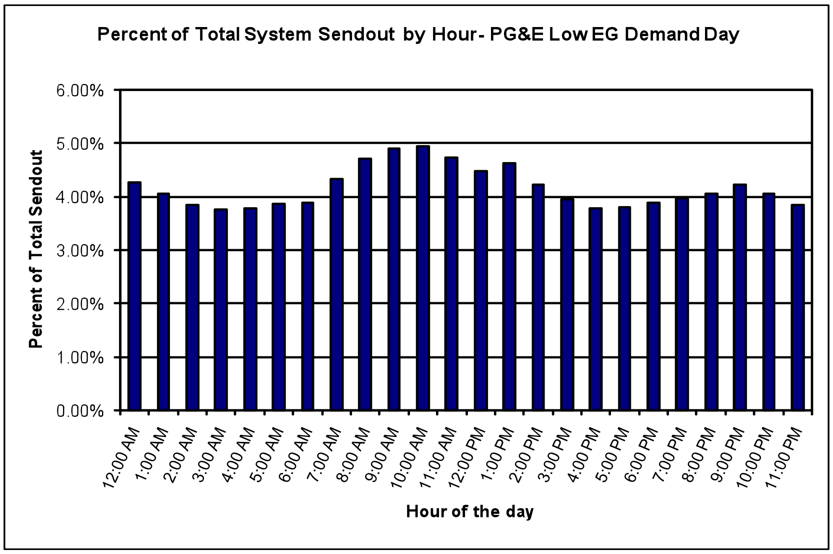


Figure 16 NR Hourly Trend – High EG Demand Day

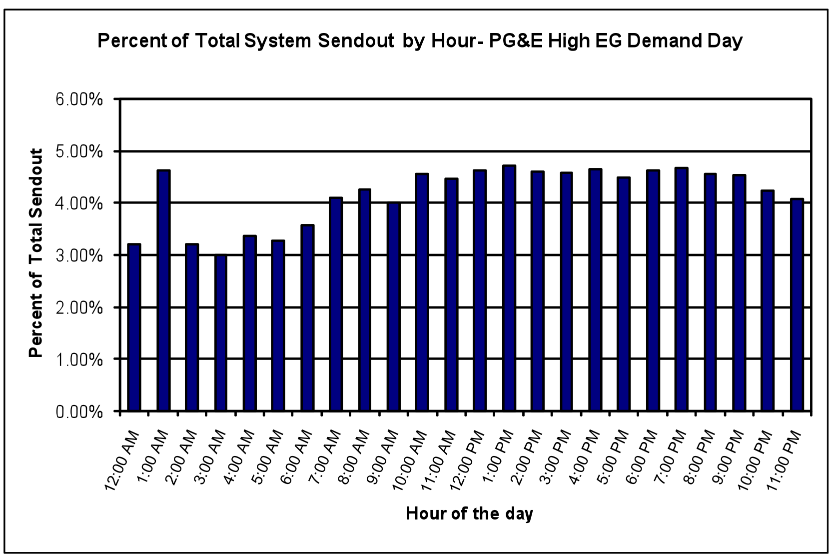


Figure 17 EG Contribution to Total System Sendout

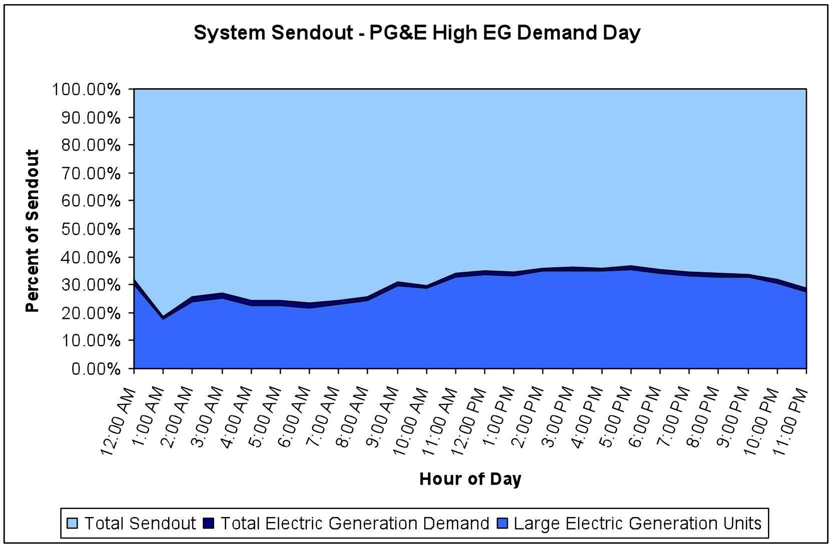


Figure 18 NR Hourly Trend Forecast

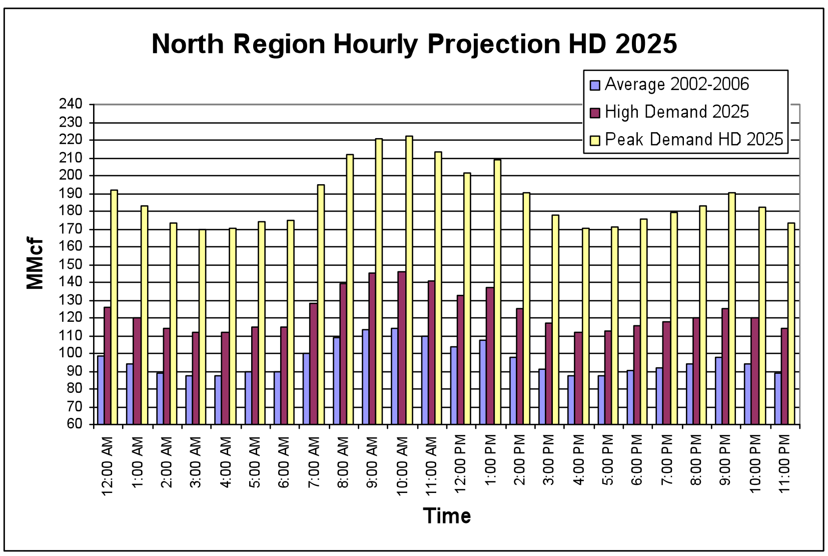


Figure 18 illustrates the projected hourly use in forecast year 2025 in both high demand as well as peak demand day scenarios.

Peak Day Demand Analysis

The general abnormal peak day (APD) calculation design criteria for PG&E is a 29 degree Fahrenheit system weighted mean temperature, or a 1 in 90 extreme temperature event as required under CEC regulation. PG&E has forecasted core load to be approximately 3.1 Bcf/d, and a total non-core load demand of 1.5 Bcf/day, which is not shown in table below. Current system planning in the event of a peak day includes meeting demand by diversion of supply from non-core segments, including gas fired electrical generation, to meet core requirements. This would lead to potential curtailments, shutting down of those facilities impacted, or operational impacts for those facilities with alternative fuel options. These options generally lead to a lack of stability in the electrical generation market. Table 5 illustrates this data.

Table 5 PG&E Peak Day Demand/Supply

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF CORE GAS DEMAND AND SUPPLY ON AN ABNORMAL PEAK DAY (APD)
MMcf/Day

	2006/07	2007/08	2008/09	2009/10	2010/11
APD Core Demand	3053	3122	3178	3213	3242
Firm Storage Withdrawal	1006	1006	1006	1006	1006
Required Flowing Supply	2047	2116	2172	2207	2236
Total APD Resources (to Meet Demand)	3053	3122	3178	3213	3242

2006 California Gas Report

GTI calculated forecasted PG&E peak day demand by using historical data in conjunction with forecasted average daily demand in both an average and high demand (HD) year 2025. The calculation utilizes the ratio of historical average daily demand to peak day demand over the past five years. This ratio is averaged over the 5 years of historical data to determine a multiplier for forecasting peak day demand requirements in 2025. Table 6 illustrates this calculation and displays projected peak day demand in forecast year 2025.

Table 6 North Region Peak Day Demand Forecast

PG&E Forecasted Peak Day Demand (2025)
MMcf/Day

	2001/2002	2002/03	2003/04	2004/05	2005/06	2025	HD 2025
Average Daily Demand	2594	2414	2360	2262	2298	*2638*	*2962*
Peak Day Demand	3824	3744	3550	3764	3267	***4018***	***4511***
Ratio	1.47	1.55	1.50	1.66	1.42		
PG&E 2025 Forecasted Peak Day Demand Ratio			***1.52***				

It should be noted that GTI's calculated peak day demand is conservative (lower) from a system demand perspective in relation to the APD generated by PG&E. This is due to the base calculation of APD being a 1 in 90 temperature event, while GTI is utilizing 5 years of operational peak day data supplied by PG&E.

PG&E also supplied data supporting the conservative nature of peak day analysis in this report. PG&E experienced a recent APD event that resulted in system curtailments. On January 11 2007, a cold snap began, ultimately resulting in temperatures reaching lows by January 13. In the 24 hour period beginning at 7:00am on January 13, system weighted composite temperatures averaged 35.4 degrees Fahrenheit, which is 13 degrees below normal. This resulted in the 6th coldest day recorded in the previous 42 years, with a subsequent system demand of 3952 MMcf/day over the time period. Supply from gas storage comprised nearly 53% of total demand, reflecting the importance of utilizing gas storage assets to meet system demand. The stress on local system capacity due to the APD event resulted in curtailment of 86 non-core customers in the San Joaquin Valley area, with a restriction of 40%-75% of planned usage. The curtailment lasted approximately 24 hours.

SOUTHERN CALIFORNIA REGION

Historical Data

Identical to Northern Region, approximately five years of historical data were collected. Please refer to Northern California Region section for a description of historical data.

Forecast Data

SoCalGas average year demand forecast projects growth of 2,641 MMcf/day (2006 actual usage) to 2,713 MMcf/day in 2025. This results in a very modest average annual growth rate of 0.14 percent across all market segments during the forecast period. The residential (0.68% average annual growth), wholesale (0.67% average annual growth), and electrical generation (0.25% average annual growth) in the extended forecast (2020-2025) were the leading market segments with a modest projected growth. This growth is offset by a decline in both commercial (0.67% average annual decline) and industrial demand (.36% average annual decline), as well as a shift of EOR customer demand to non-utility pipeline systems. A summary of each key segment is provided below.

Several factors and assumptions were used to generate the forecast by SoCalGas. Economic outlook, pricing forecasts, energy efficiency programs, and regulatory matters were four primary factors in the model. A brief summary of these factors are provided below. More detailed information on each of these important elements of forecasting can be found in the CEC website and literature, the Integrated Energy Policy Report (IEPR), and the NYMEX futures reports.

The economy in SoCalGas's service territory has experienced a decline in growth over the past several years in relation to the mid to late 1990's. A key driving factor in the slowing economy has been industrial employment, which is nearly 30% below industrial related jobs in 1990. Nearly all other economy segments are experiencing modest growth. Commercial jobs have experienced growth, with the fastest rates coming in the business and professional services industry at approximately 1.3% annually. Commercial job growth is expected to average 1.0% throughout the forecast parameters. Population in the service territory is expected to grow at an average of 1.2% annually, with driving factors being housing costs and foreign immigration. Due to modest growth in population and households, SoCalGas expects active meters to increase approximately 1.3% annually from 2007 to 2025.

Energy efficiency and conservation programs have a significant impact in projecting natural gas usage in southern California. They encourage consumers to utilize energy efficient equipment and adopt energy saving practices that ultimately reduce gas usage. SoCalGas is projected a net "savings", or reduction in gas usage of nearly 50 Bcf by 2025. Details of the SoCalGas energy efficiency program can be found in Advice Letter 3588.

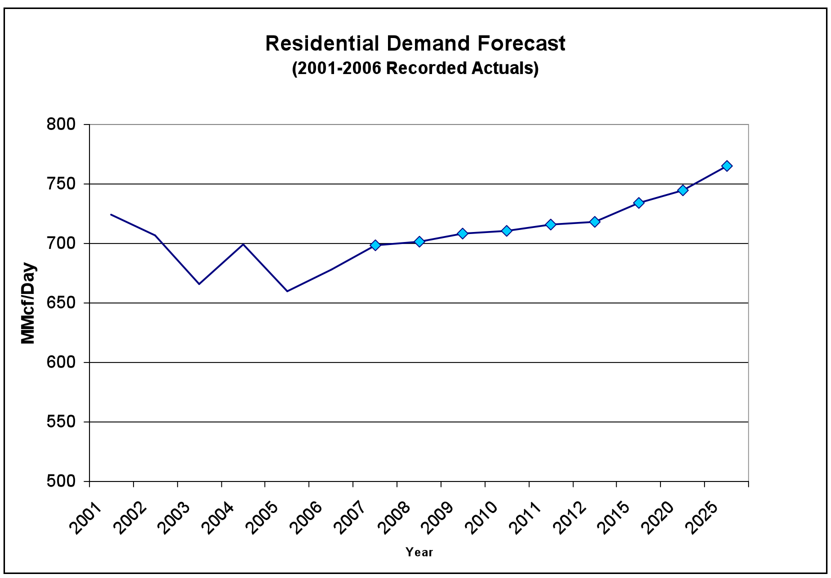
The peak demand scenario supplied by SoCalGas is based on criteria defined as a 1-in-35 likelihood event, or approximately a 27 degree day (65 degree F base). Demand forecasts were submitted by SoCalGas for two temperature scenarios, average and cold. As temperature variations have a significant impact on residential space heating requirements as well as commercial and industrial applications, it is important to account for this. Differences between them are developed from a six-zone temperature monitoring procedure based on heating degree days (1 HDD = 65 degrees F – 1 degree F). Forecast data is included in the Appendix.

Market Sectors

Residential

Based on forecasting data, residential demand in the SoCalGas service area is forecasted to grow at approximately 0.68 percent annually from an actual 2006 value of 678 MMcf/d to projected consumption of 765 MMcf/d in an average temperature year, and 0.85 percent in a cold temperature year through 2025. This value is derived from an overall projected increase of 1.3 percent increase in meters coupled with an annual decrease in gas use per meter of nearly 0.7 percent. This is a direct reflection of appliance and insulation efficiencies as well as cumulative effects of energy efficiency programs. Recent studies (IEPR Update) show a slight increase in projected residential growth over the forecast period due to higher population growth projections.

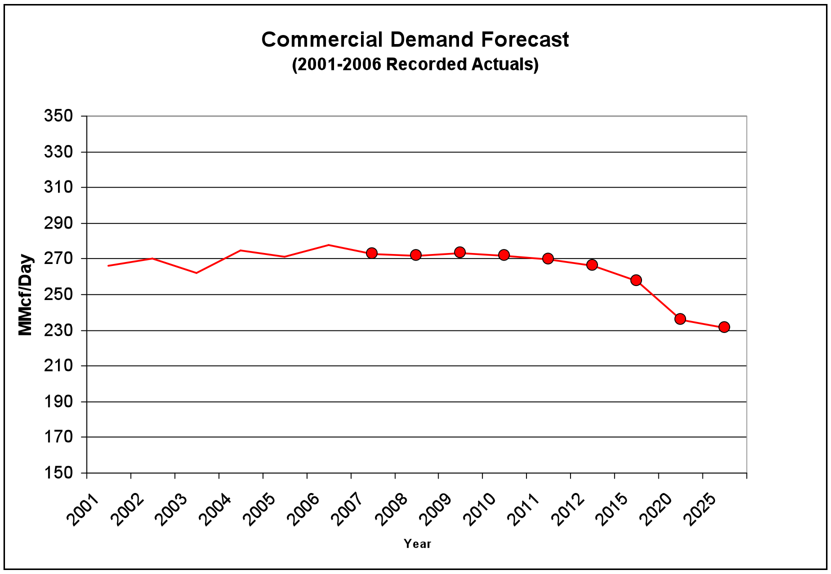
Figure 19 SR Residential Demand Forecast



Commercial

SoCalGas commercial demand forecast indicates growth from 278 MMcf/d (recorded 2006) to 231 MMcf/d in 2025 for an average annual decline of just over 0.88 percent. The decline is the result of facing identical energy efficiency programs as North Region as indicated earlier, The overall decline does reflect a more moderate decline rate in the non-core commercial market, which is the result of a relative projected increase in economic activity in agriculture, health, transportation, communication, and utilities industrial sectors, as indicated in the 2006 CGR. Decline in the commercial segment is driven by the core commercial sector.

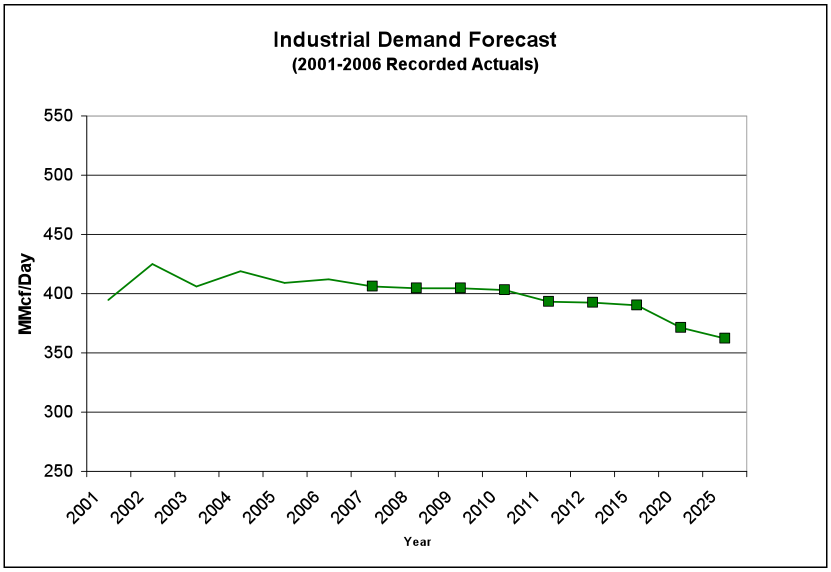
Figure 20 SR Commercial Demand Forecast



Industrial

Industrial gas consumption is expected to decline over the forecasted period by approximately 0.64 percent from a recorded 2006 value of 412 MMcf/d to 362 MMcf/d in 2025. This is generally the result of moderate declines in both the core and non-core sectors of the industrial segment. The gradual consumption decline is the net result of several sectors within the industrial segment. It is comprised of a modest growth in the food sector, a modest decline in the transportation sector, a slight decline in the retail non-core and refinery sectors, and primarily due to an expected downturn in economic activity in the mining and petroleum sectors. The projected effect of energy efficiency programs is also contributing to the overall demand decline in the industrial sector.

Figure 21 SR Industrial Demand Forecast

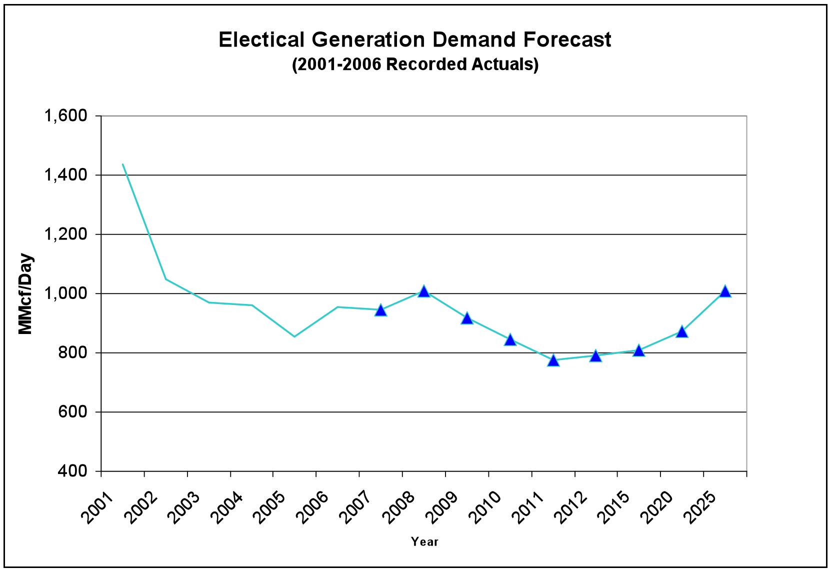


Electrical Generation

As noted by SoCalGas, as well as industry forecasts, key assumptions resulting in higher uncertainties in the electrical generation forecast include new generation facilities and their expected on-line dates, operation of existing EG facilities, regulatory and environmental regulation impacts, and construction of renewable energy resources. Included in this forecast are all commercial/industrial cogeneration, EOR related cogeneration, non-cogeneration electrical generation, and wholesale and international based electrical generation. Wholesale demand includes transportation to SDG&E, city of Long Beach Electric and Gas Department, Southwest Gas, and the City of Vernon. The forecast also assumes base electricity demand and average hydroelectric market conditions. Other influencing factors and basis for this forecast is outlined and can be further reviewed in the 2006 CGR.

SoCalGas forecasts a growth in demand from a recorded 2006 volume of 964 MMcf/d to 1010 MMcf/d in 2025, or approximately a 0.25 percent average annual increase. This reflects a modest increase in industrial/commercial cogeneration sector, tempered by decreases in other EG sectors. A strong increase in demand is expected in the last 10 years of the forecast due to the forecasted construction of approximately 50,000 MW of new thermal electric power generating resources.

Figure 22 SR Electrical Generation Demand Forecast



South Region Gas Demand Trends

Historical and Forecast Growth Trends

Similar to North Region historical data described in earlier sections, data were gathered and illustrated to develop demand trends for each potential market segment identified. SoCalGas supplied historic data including Core (residential and commercial combined), and Non-Core (Industrial, EG, Cogen) with electrical generation further segmented from Non-Core data. Trends for each market segment illustrated were calculated by averaging usage from four years of historical data supplied (2003-2006), and extrapolated to reflect forecasted demand values calculated by SoCalGas's forecast model.

Core Segment

Core consumer usage trends are historically very consistent and are projected to remain so in the forecast period. While certain variables or technologies may impact the rate of growth in a particular segment, usage trends remain unchanged or negligibly impacted. For example, energy efficient appliances and higher commodity costs moderated the growth of the residential market segment, but residential consumers hourly, daily, and even seasonal usage patterns reflect heating and cooling seasonal requirements, as well as traditional work patterns for residential use scenarios. Figure 23 and Figure 24 illustrate historic core usage and forecasted core usage.

Figure 23 SR Historic Core Usage

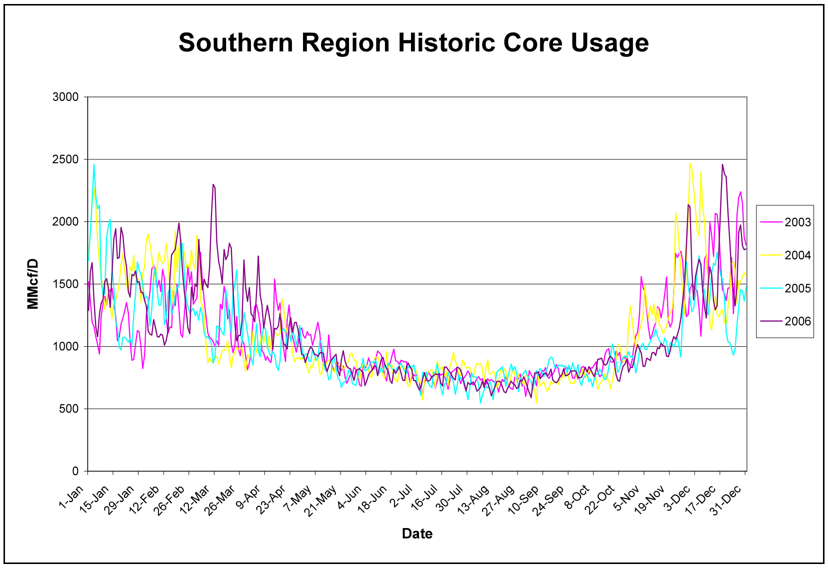
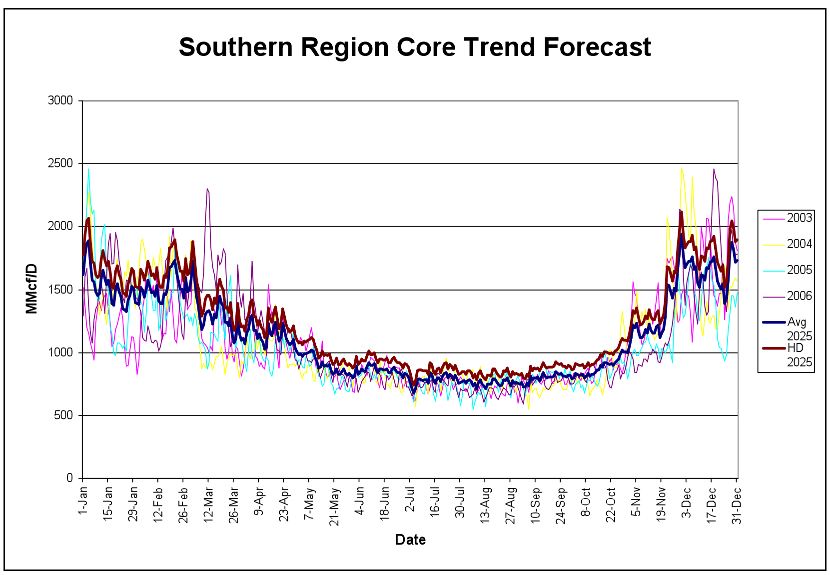


Figure 24 SR Core Trend Forecast



Non-Core Segment

The non-core segment usage trends primarily reflect electrical generation patterns. It is apparent in

Figure 25 EG demand has a single peaking season in June, July, and August while the remainder of the year shows relatively consistent usage. As EG demand for cooling is significantly driven by temperature, it will remain relatively consistent over time. This phenomenon is reflected in the Non-Core trend forecast in Figure 26.

Figure 25 SR Historic Non-Core Usage

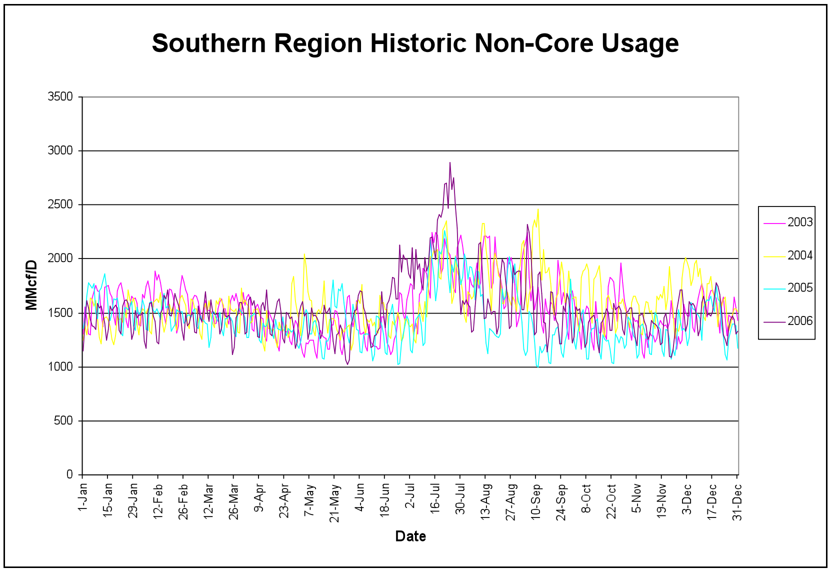


Figure 26 SR Non-Core Trend Forecast

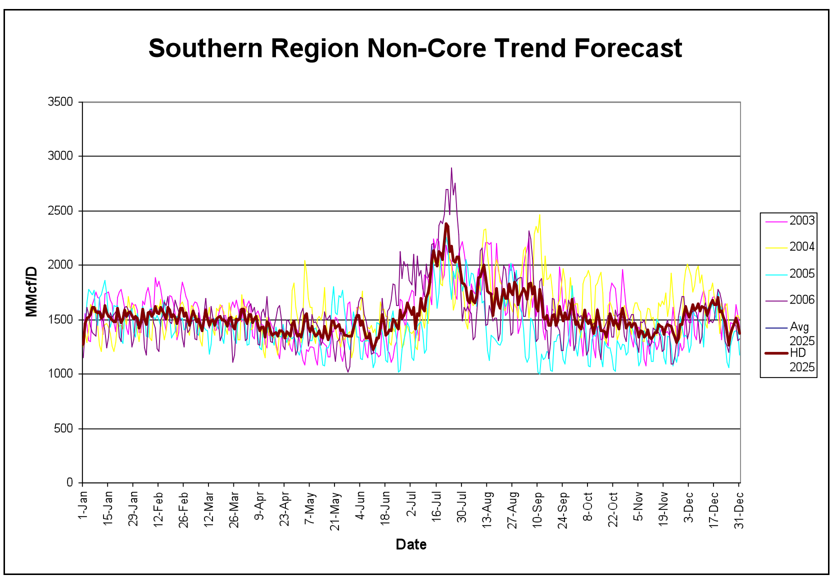
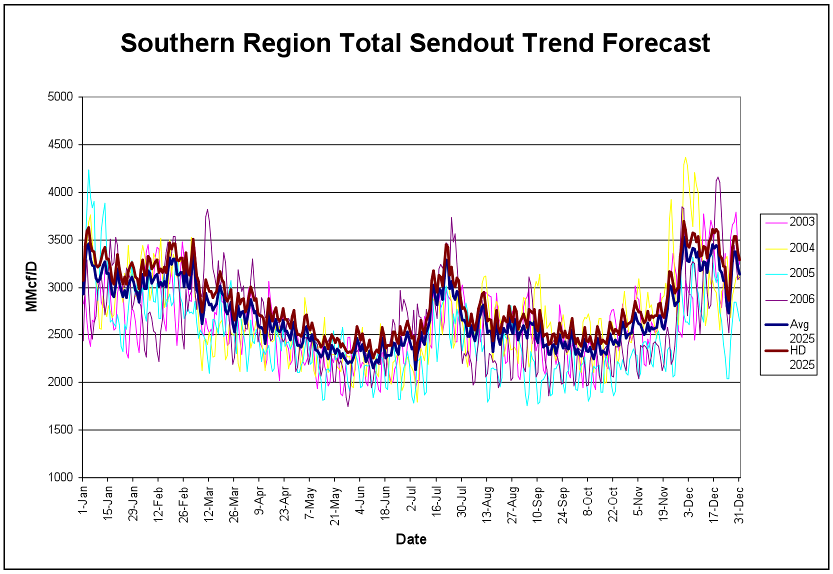


Figure 27 SR Total Sendout Trend Forecast



Seasonal Variations

The forecasted trending illustrated in the previous graphs identifies forecasted seasonal variations within each key segment. Data is similar to that described in the North Region section of this report. Core, Non-Core (specifically Electrical Generation), and Total South Region (Figure 27) demand all display very consistent, cyclic usage over the course of a calendar year. Four years of historical data were analyzed for the purpose of this study. As stated in the North Region analysis, seasonal usage patterns, and therefore demand forecasts, are not expected to significantly change in the forecast period addressed in this research.

Natural Gas Storage Utilization

As described in the previous section, the two primary benefits of utilizing gas storage is to supplement and augment pipeline deliveries and provide a cost effective, reliable source of natural gas to consumers in both a seasonal and peak demand capacity. The following histograms (Figures 28-32) reflect gas storage utilization in SoCalGas's service territory over the past five withdrawal seasons. Gas storage contribution is represented as a percentage of overall system sendout to consumers.

Figure 28 SR 2002/2003 Gas Storage Utilization

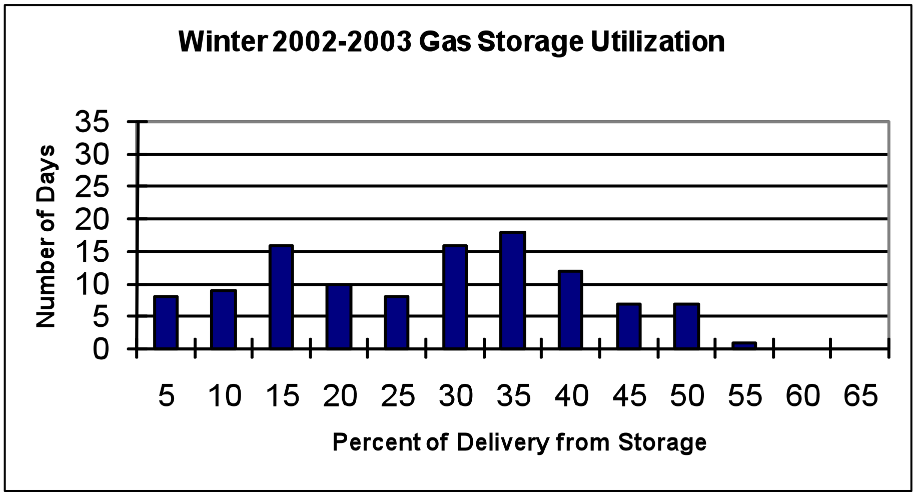


Figure 29 SR 2003/2004 Gas Storage Utilization

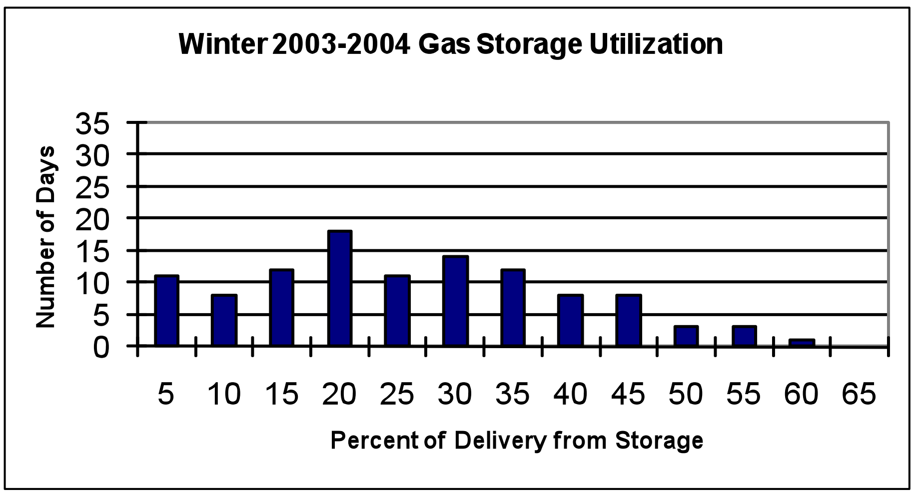


Figure 30 SR 2004/2005 Gas Storage Utilization

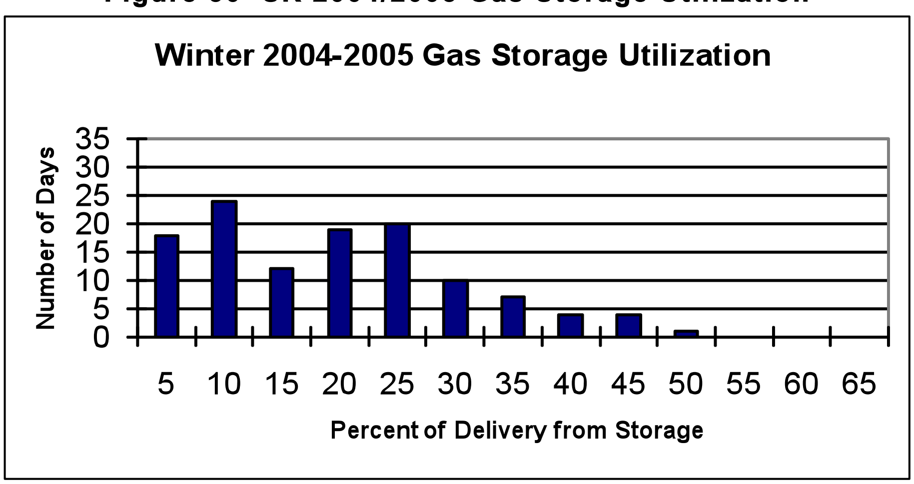


Figure 31 SR 2005/2006 Gas Storage Utilization

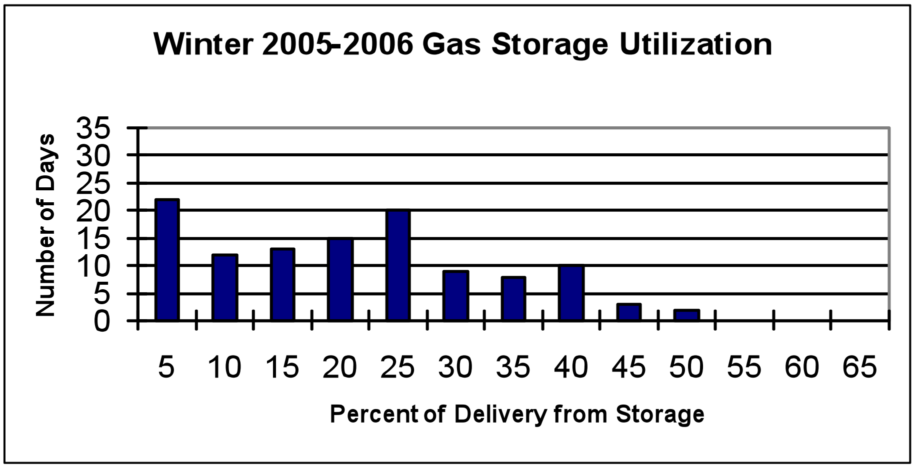
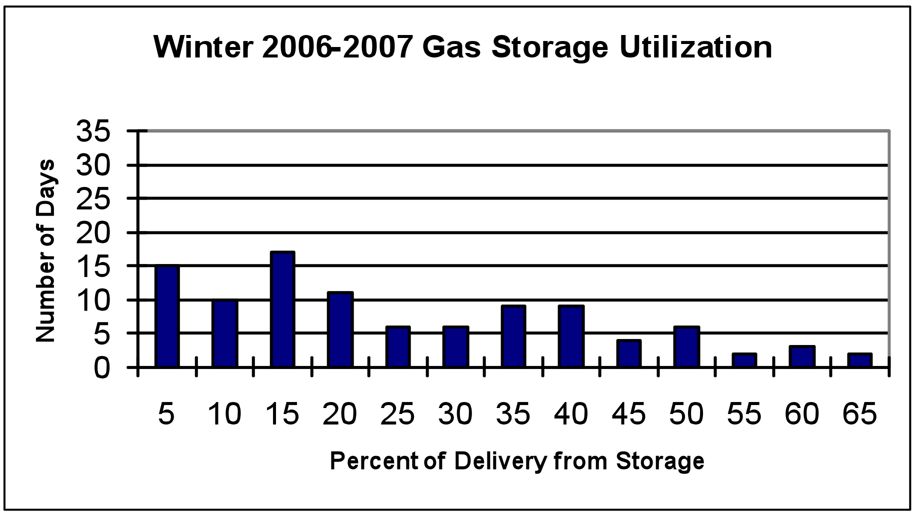


Figure 32 SR 2006/2007 Gas Storage Utilization



The data illustrated in the histograms reinforce the importance of these critical gas storage assets in meeting California and South Region natural gas demand. On critical days, as outlined in the Peak Day Demand Analysis section below, an average of nearly 60% of total system sendout is supplied from underground natural gas storage, resulting in significant economic benefits and gas delivery reliability to the customer base. Comparatively, in the North Region section of this report, PG&E underground natural gas storage accounted for an average of nearly 40% of their total system sendout on similar critical days. This data highlights the significance of gas storage as a critical component of both PG&E's and SoCalGas's supply portfolio.

Hourly Demand Variations

Hourly data was supplied by SoCalGas to enable GTI to provide hourly trending analysis. Similar to PG&E, SoCalGas does not typically capture and record this data on a continual basis or by segment. Figure 33 illustrates both Core and Electrical Generation usage as a percentage of total daily sendout. Figure 34 further segments total system sendout into all supplied sectors, including core

usage by SoCalGas, SDGE, SoCalGas Non-Core usage, and Electrical and Co-Generation.

Figure 35 depicts the total sendout trend forecast through 2025 for South Region. Hourly forecasts are calculated using a percent volume base per hour and extrapolated to reflect average and peak demand day volumes (including the more conservative scenario supplied by SoCalGas) in the forecast year 2025. GTI acknowledges the hourly trends illustrated in the following figures reflect only snapshots in time and are not based on continuous hourly data.

Figure 33 SR Core and EG Hourly Trend

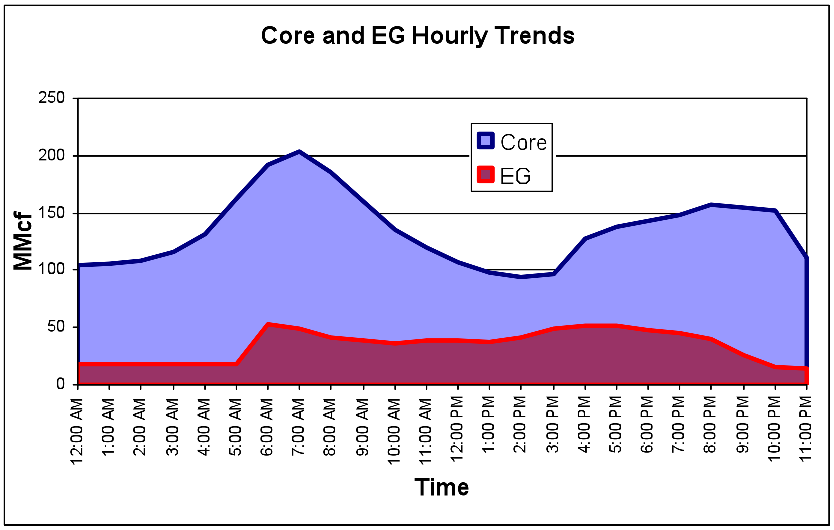


Figure 34 NR Hourly Usage by Sector

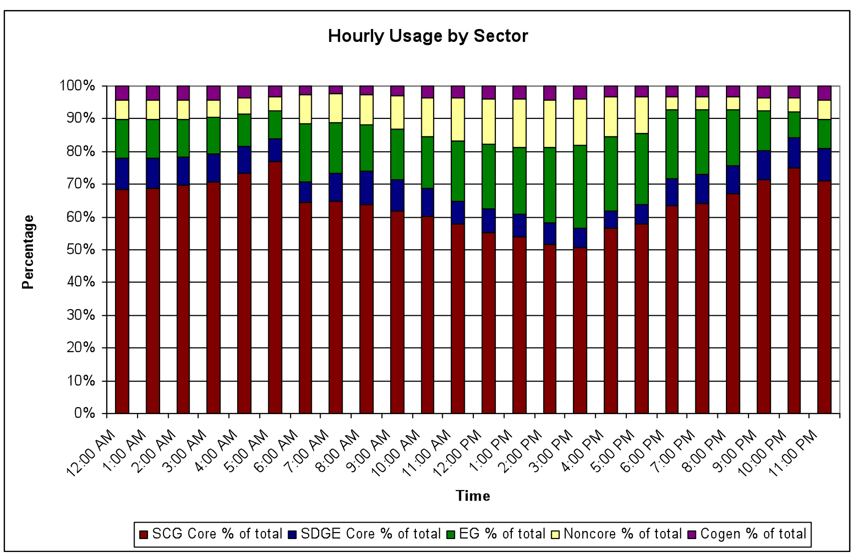
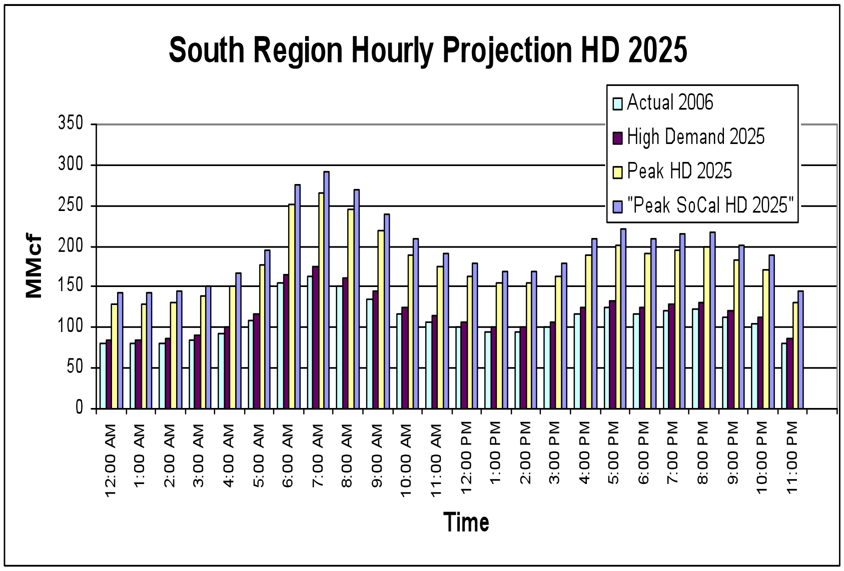


Figure 35 SR Hourly Projection



Peak Day Demand Analysis

The peak day calculation design criteria for SoCalGas is a system average temperature of 38 degrees Fahrenheit, or a 1 in 35 likelihood event. SoCalGas has forecasted core load to be approximately 3.5 Bcf/d, and a total non-core load demand of approximately 2.2 Bcf/day in 2007. This demand is met through a combination of withdrawals from underground gas storage and interstate pipeline supply.

Table 7 provides an illustration of core demand and supply.

Table 7 SoCalGas Peak Day Demand/Supply

SOUTHERN CALIFORNIA GAS COMPANY
RETAL CORE PEAK DAY DEMAND AND SUPPLY REQUIREMENTS
MMcf/Day

	2006	2007	2008	2010
Retail Core Demand	3537	3536	3633	3788
Firm Storage Withdrawal	1963	1963	2016	2102
Required Flowing Supplies	1574	1573	1617	1686
Total Peak Day Resources (to Meet Demand)	3537	3536	3633	3788

2006 California Gas Report

GTI calculated forecasted SoCalGas peak day demand by using historical data in conjunction with forecasted average daily demand in both an average demand (temperature) and high demand year 2025. The calculation utilizes the ratio of historical average daily demand to peak day demand over the past four years (2003 – 2006). This ratio is averaged over the 4 years of historical data to determine a multiplier for forecasting peak day demand requirements in 2025. Table 8 illustrates this calculation and displays projected peak day demand in forecast year 2025.

Table 8 SoCalGas Peak Day Demand Forecast

SoCalGas Forecasted Peak Day Demand (2025)
MMcf/Day

	2002/03	2003/04	2004/05	2005/06	2025	HD 2025
Average Daily Demand	2608	2698	2483	2641	*2713*	*2828*
Peak Day Demand	3820	3789	4370	3814	***4119***	***4294***
Ratio	1.46	1.40	1.76	1.44		
SoCalGas 2025 Forecasted Peak Day Demand Ratio			***1.52***			

As previously stated, GTI utilized ratios derived from historical data to calculate future peak demand requirements. Additional information supplied by the Design Forecasting Group (Herb Emmrich, Manager Design Forecasting Group) of SoCalGas describes a recent peak day event with a brief description of resulting potential system impacts. This information was not included in the historical data packages, therefore is not reflected in GTI's analysis but is relevant and pertinent to this report. The event is described below.

The minimum temperature event occurred on Sunday, January 14th, 2007, when SoCalGas experienced a system-average temperature of 41.7°F. This value is fairly close to the "1-in-10" likelihood peak-day design temperature of 41°F. Five days prior, on January 9th, the system average temperature was 65.7 °F, and for the next four days the temperatures dropped successively to: 58.7°F, 53.4°F, 47.3°F, and 44.0°F, respectively, on January 10th, 11th, 12th and 13th, 2007.

On the day this temperature event occurred, for the 2006/2007 winter period, SoCalGas' total system send-out was 4,402 MMcf, with total core gas demand (including any company use fuel and "un-accounted-for" gas) of 2,683 MMcf—also, the peak-day of core gas load that winter. Receipts of "flowing gas supply" amounted to 1,891 MMcf, with corresponding net storage withdrawals of 2,511 MMcf. Although SoCalGas did not curtail gas service to any customers on that day, if the system average temperature had been about 4°F lower, at 38°F, SoCalGas may have needed to initiate curtailment procedures. In fact, even though these aggregate system characteristics suggest "no problems" there may arise a situation where equipment associated with movement of gas through the system could fail and create a need to curtail service.

The peak day event description supplied by SoCalGas corroborates previous peak day analysis as the 4,402 MMcf total system sendout is more conservative than the historical data used in this study. The 4,119 MMcf total sendout projected for 2025 is an average temperature based demand year reflecting a modest increase in projected customer base demand and the historically based calculated peak day ratio multiplier. A "1-in-10" event would inherently increase the calculated ratio reflecting a higher total daily sendout in 2025, or approximately 4,530 MMcf, resulting in probable system curtailments based on current infrastructure capacity.

This event is also consistent with analysis included in the Natural Gas Storage Utilization section of this report in that the actual usage of gas storage assets in meeting peak day demand requirements account for approximately 58% of total demand.

Comparative illustrations of peak day analysis between PG&E and SoCalGas are included in Section 3.3.

3.3. Conclusions and Recommendations

Much of the information contained within Section 3.0 is a representation of historical and forecasting data supplied by the two largest natural gas utilities operating in the State of California; Southern California Gas Company and Pacific Gas and Electric. Projecting natural gas demand over the forecasting period of approximately fifteen years required assumptions in energy policy, temperature related seasonal variations, shifting economic trends, and changing demographics as described within the report. These assumptions and variables are taken into account when defining the projections, resulting in steady but very moderate growth statewide in natural gas demand over the forecast period. Market segments such as electrical generation and residential use, showed increased demand but was tempered by decreased projected demand in the industrial segment and other market segments. The gas fired electrical generation market, with high expected growth, was tempered by factors including displacement of existing plants by new efficient (over 30% more efficient) plants, new electrical generation plants in neighboring states serving California, and locations of some new plants taking service directly from interstate pipelines which effectively reduce demand on the utility systems[2].

Seasonal and Daily (Hourly) trends were illustrated using historical data as a base reference, and extrapolated to adjust for forecasted volumes. A significant variable in establishing seasonal trends is temperature related, and therefore is expected to remain relatively consistent over the forecast period and is corroborated by extensive historical data. Natural gas usage as a preferred fuel in the electrical generation market segment, a segment with relatively significant growth projections, will also remain consistent in its cyclic nature as its primary usage is for cooling. Peak usage will increase as base demand for natural gas fuel increases over the forecast period, but its fundamental usage pattern is expected to remain consistent with historical patterns.

Hourly forecasts were calculated using a percent volume base per hour and extrapolated to reflect average and peak demand day volumes in the forecast year 2025. In the relatively more conservative scenario described above (1-in-10 event), hourly forecasted trends indicate nearly 1.1 Bcf of natural gas deliveries will be required on the SoCalGas system over the course of just 4 hours (6am – 10am). PG&E's system indicates a requirement of approximately 870 MMcf over a similar four hour period (8am – Noon).

Peak Day Demand scenarios outlined in the report were based on historically calculated ratios, extrapolated to reflect forecasted values. Utilizing a direct approach based on 5 years of historical data, calculated peak day demand is inherently lower than individual models used by PG&E and SoCalGas. From a system planning requirement perspective, this is a less conservative approach and should be noted as such. More conservative actual peak day scenarios were supplied by SoCalGas and PG&E and are included in the report as well. Table 9 summarizes the peak day demand scenario as well as supply portfolio capacity available to meet forecasted demand. Both an average demand (temperature, hydro conditions) and high demand scenario are included in the table for the forecast year 2025. Also included is the

[2] CPUC, California Natural Gas Infrastructure Outlook, 2002-2006

alternate peak day event supplied by SoCalGas reflecting a "1-in-10" event. The number is in parenthesis and does not reflect a negative contribution.

Table 9 Statewide Peak Day Demand Analysis

STATE OF CALIFORNIA PEAK DAY DEMAND ANALYSIS
(MMcf/Day)

		2025	HD 2025
PG&E Peak Day Demand		*4018*	*4511*
SoCalGas Peak Day Demand		*4119*	*4294*
(SoCalGas Alternative Peak Day Event)		*(4530)*	*(4722)*
Non-Utility Peak Day Demand		*2245*	*2430*
Total California Demand		*10382*	*11235*
		(10793)	*(11663)*
California Gas Storage Withdrawal Deliverability			
	Southern California Gas Co.		*3175*
	Pacific Gas & Electric		*1996*
	Wild Goose		*480*
	Lodi		*500*
	Lodi - Kirby Hills		*50*
			6201
California Interstate Pipeline Capacity			
	El Paso (North &South)		*3710*
	Transwestern		*1210*
	Kern River		*1830*
	Southern Trails		*80*
	GTN - TransCanada		*2190*
	California Sources		*328*
			9348
Total Peak Day Resources Available			*15549*

Based on interstate pipeline capacity ratings and gas storage deliverability (data supplied directly from gas storage operating companies), there appears to be adequate supply capacity to meet forecasted demand over a forecast period of approximately 15 years. Even in a high demand peak day event, there is an estimated infrastructure capacity surplus of nearly 4,000 MMcf/day, or a reserve margin of 33%.

Although analysis found within this report supports the conclusion that the State of California is adequately positioned (infrastructure capacity) on an aggregate basis to meet demand requirements over the forecast period of approximately 15 years, there are many assumptions made that could have a significant impact on the projections calculated. Further analysis and investigation into the base assumptions as well as forecasting models should be periodically performed to ensure a proactive approach in providing reliable and adequate infrastructure to continue to meet projected natural gas demand.

Trending and peak day analysis provided insight into future demand requirements from a more localized infrastructure perspective as well as over a short period of time. Though detailed local infrastructure modeling and analysis was not within the scope of this report, data does indicate the local system will continue to be stressed as demand grows. This brings into question whether local utilities can continue to meet growing demand of the customer base. In discussions with SoCalGas and PG&E, each operating utility expressed concern whether theoretical system capacity and deliverability could be achieved and perhaps exceeded under conditions experienced in peak day events. These concerns are further supported by supplied data on recent peak day events from both SoCalGas and PG&E, with the latter resulting in system curtailments. Further research is recommended to investigate the ability of local infrastructure to provide natural gas in sufficient volumes to satisfy customer demand over the forecast period. In particular, deliverability of local transmission and distribution systems to supply up to 1.1 Bcf of natural gas in a four hour window in SoCalGas territory, as well as nearly 900 MMcf in PG&E's service territory. In addition to these significant volumes, other variables should be considered such as line pressure limitations, pipeline bottlenecking, upstream demand on interstate pipelines limiting volumes in high demand scenarios, and linepack capacity for balancing purposes.

Given the magnitude of uncertainty on the use of natural gas as the preferred near and midterm solution for power generation under GHG legislation, a one to three Tcf addition to the baseline forecast increases the natural gas demand required for power generation by nearly 50% over the last 10 years of the forecast. Particularly in California, this could add considerably to peak load demand in the summer, providing support to the recommendation that the CEC should explore ways to enhance gas deliverability by conventional and alternative gas storage options, even if current and anticipated margins of safety are high.

As a result of analysis focusing on gas storage utilization, it is recommended the State of California continue to consider developing or enhancing gas storage facilities for both increased reliability in meeting consumer demand as well as ensuring delivery of cost effective natural gas to the customer meter. Gas storage is a critical component of the supply portfolio both in a base volume as well as in peak day scenarios, as shown in the current utilization of traditional operating assets.

Recommendations Summary:

- Continued analysis and investigation into the base forecasting assumptions as well as models should be periodically performed to ensure a proactive approach in providing realistic demand projections. This will ensure adequate time to implement potentially necessary infrastructure (storage or pipeline) to continue to meet projected natural gas demand.
- Further research is recommended to investigate the ability of local infrastructure to provide natural gas in sufficient volumes to satisfy customer demand over the forecast period, particularly deliverability of local transmission and distribution systems to supply up to 1.1 Bcf of natural gas in a four hour window in SoCalGas territory, as well as nearly 900 MMcf in PG&E's service territory.
- The State of California should continue to consider developing or enhancing gas storage facilities for both increased reliability in meeting consumer demand as well as ensuring delivery of cost effective natural gas to the customer meter.

4.0 Define California Natural Gas Storage Deliverability Options

4.1. Project Approach

Introduction

Section 3.0 analysis concluded that forecasted infrastructure capacity on an aggregate level appears adequate over the forecasting period identified. However, an operational concern evolved from the research performed that local natural gas distribution infrastructure in some locales may not be adequate for meeting extreme peak demands. Therefore, this portion of the report analyses point source storage technologies as well as improvements in conventional natural gas storage that could be used to meet peak day demands by supplementing local transmission and distribution network systems.

Technology Selection Criteria

The primary selection criteria for identifying technologies were those that could be applied as a point source, or in a dispersed energy operating environment and provide on demand natural gas to supplement the local distribution and transmission pipeline networks.

Advances in traditional gas storage deliverability enhancement technologies that provide incremental, cost effective natural gas to the transmission pipeline network are also investigated in this research. These particular technologies are not focused on supplementing pipeline networks, but rather on maximizing the efficiency of California's traditional underground gas storage assets.

Other considerations in identifying applicable alternative gas storage technologies include:

- *Flexibility* of technology – technologies identified require the flexibility of being integrated directly into a transmission or distribution pipeline or have the ability to provide natural gas to a specific large industrial customer such as an electrical generation facility.
- *Maturity* of technology – the overall maturity of the inherent technology is taken into consideration. Those selected for further analysis should exhibit potential for commercialization and application within the next 5 to 15 years. Conversely, highly mature technologies such as traditional CNG and LNG storage were excluded. Variations of these technologies, such as "chilled" CNG or alternatively scaled LNG due to advancements in system process, were included in the analysis.
- *Scalability* of technology – the systems selected for further analysis should meet the minimum effective volume requirements of operating scenarios defined by California operating utilities. This is to ensure they will provide value to California consumers. These scenarios are further defined in Section 4.1.3, Operation Feasibility.
- *Geological Constraints* – any traditional or man-made underground technologies selected for review must meet geological considerations prevalent in California. For example, there are no naturally occurring salt formations currently identified in the state, precluding salt cavern development

Based on the criteria above, certain traditional gas storage capacity enhancement technologies were excluded from further review. Examples of these include the utilization of inert gases like nitrogen to maximize working gas capacities (single instance benefit), as well as high deliverability storage technologies such as salt caverns.

Technology Review

Technologies included in this research were evaluated for their operational feasibility, specifically to those California-based operating scenarios described within this section, and also in general terms of basic research. Economic feasibility is also addressed for each of those technologies mature enough in its development for relevant evaluation. Each technology review follows a reporting structure organized in four general topics.

Technology Description

This section focuses on providing a description of the technology's underlying basic science and brief history of research and development.

Operational Feasibility

Review of the operational feasibility for each technology in this section was accomplished with two primary goals in mind. The first was reviewing the underlying processes inherent to the technology's application to verify and ensure its ability to meet the selection criteria indicated above. Examples included its flexibility of intended application as well as its ability to perform under different scaling environments.

The second, equally important goal of each technology reviewed was analyzing its specific application to three operating scenarios identified by California operating utilities SoCalGas and PG&E. Applying each technology to these operating scenarios ensures the needs of California consumers are addressed. The operating scenarios were chosen due to their relevancy to potential concerns expressed by the two utilities in meeting peak day demand events. For instance, natural gas enters the San Diego Gas and Electric Company (a wholesale customer of SoCalGas) system primarily at the Rainbow Station. Should flow through Rainbow Station be compromised or reduced in any way, such as by compressor failure, SoCalGas would be at risk of not meeting demand under certain conditions.

It should be noted that traditional gas storage deliverability enhancement technologies reviewed within this report do not generally apply to operational scenarios identified and are therefore excluded from scenario analysis. These technologies focus on increasing incremental deliverability in underground storage fields rather than point source applications providing supplemental capacity to pipelines. They include hydraulic fracturing, advanced drilling techniques, and laser based enhancement applications.

A summary of each operating scenario follows:

Operating Scenario 1 – This operating scenario specifically addresses the ability of each technology to provide natural gas supply to large industrial consumers on distribution or transmission pipeline networks. For example, a large natural gas driven EG facility can have significant needs in various peak day demand scenarios. The ability to serve this customer independently of the other system requirements provides the operating utility flexibility in meeting its core customers and prevents a potential need to curtail its noncore customers. This particular operating scenario can also provide the EG facility price leveraging benefits in those situations when demand is considerably higher than what is stipulated in firm contracts with utilities or pipelines. Rather than purchasing premium priced natural gas in the spot market, or switching to an alternative fuel if available, supplemental gas will be supplied by the gas storage mechanism on site. Basic operating conditions of this scenario include:

- Approximately 2 MMcf/hour to 3 MMcf/hour flow requirements over a 10 to 14 hour time period, or from 7:00 am to 7:00 pm on average. This time frame reflects typical heavy hourly usage trends on peak day demand events. Depending on the technology, this also provides an opportunity to replenish storage supplies during off-peak hours.
- Delivery pressure of the system, or outlet pressure, is estimated at approximately 300 psig. Regulation could potentially be bypassed for efficiency purposes and delivered directly into a 60 psig or less system.

Operating Scenario 2 – This scenario specifically addresses those situations where distribution and transmission infrastructure present a bottleneck during high demand operating conditions. A potential example of this is the ability of SoCalGas to serve its customer base in SDG&E's territory, which requires nearly 550 MMcf/day by the end of the forecast period stipulated in Section 3.0. The pipeline serving that territory can be affected by both its inherent capacity limitations (pipe diameter, pressure) as well as a lack of adequate supplies from interstate pipelines delivering to that station. Potential benefits of this technology application include reliable and consistent natural gas delivery to consumers as well as providing a potential alternative to installing large diameter pipeline to increase capacity and throughput to the location. Not only is this very costly, but siting (easement) and permitting considerations must be addressed. This operating scenario implies system integration with the transmission pipeline and siting downstream of the bottleneck to ensure adequate throughput. Basic operating parameters of this scenario include:

- Approximately 4 MMcf/hour to 6 MMcf/hour flow requirements over a 10 to 14 hour time period, or from 7:00 am to 7:00 pm on average. This time frame reflects typical heavy hourly usage trends on peak day demand events. Depending on the technology, this also gives an opportunity to replenish storage supplies during off-peak hours.
- Delivery pressure of the system, or outlet pressure, is estimated at approximately 500 psig. This reflects direct integration with transmission pipelines serving large customer bases.

Operating Scenario 3 – Operating scenario 3 is focused on providing supplemental natural gas is situations of planned and unplanned system outages. This includes emergency outages due to damaged pipelines as well as planned system improvements potentially affecting hundreds or thousands of consumers. The natural gas storage systems reviewed for applicability to these conditions are required to be self contained and highly mobile. An example of how this need is currently being met by operating utilities is through utilization of truck/trailer mounted high pressure (3600 psig) CNG vessels. Applying alternative gas storage technologies to this scenario can provide operational benefits including:

- Density benefits of phase change provide significantly more capacity per volume unit than traditional CNG. This additional capacity implies either longer service per incident, solutions for larger outages, or fewer numbers of vessels/trucks to maintain service.

- Supplemental natural gas can be stored at lower pressures, eliminating some of the inherent safety and permitting concerns with high pressure CNG vessels.
- Operational fleet costs can be reduced significant as fewer vehicles will be required for natural gas transport.
- Proposed natural gas storage system could potentially compete with geographical rural locations currently being serviced by propane fuel.

Due to the nature of operational requirements, certain technologies identified for further research do not necessarily appear feasible for this particular application. For example, lined rock caverns or natural gas hydrate storage would not be candidates for this scenario due to either fixed assets (LRC) or inherent process limitations requiring significant on-site facilities.

An example of this type of operating scenario utilized for evaluating specific technologies in this report assumes a residential outage of approximately 1,000 customers on a high pressure distribution pipeline (60psig).

Economic Feasibility

Providing a complete and accurate economic feasibility analysis has inherent difficulties as the technologies identified are in various developmental stages. Manufacturers and developing institutions were contacted in each case to provide approximate costs of system integration based on the various operating scenarios and related components. Where applicable, capital as well as operational expense estimates were provided for each operational scenario. The intention of this report is to provide an idea of potential system costs and not necessarily to recommend a particular technology in a specific case.

In peak day demand scenarios, displacement costs would include the differential between spot market prices of gas (approximately $10 to $20 per Mcf in some cases) above the firm contract supply and any additional incremental operating costs incurred by the technology applied. In a simplified example, an EG facility may require an additional 20% volume of natural gas above their firm contracted supply to meet peak day demand. Utilizing an alternative gas storage technology for supply, this 20% requirement was stored at a commodity cost similar to that of the firm costs, or $7 per Mcf. Operational costs of delivering that storage natural gas add an incremental cost of $3 per Mcf for an approximate total delivery cost of $10 per Mcf. This would then be compared to the spot market price of $15 per Mcf, assuming that volume was available on the pipeline for purchase, and utilized to calculate a ROI taking into consideration initial capital expenditures.

A second simple economic feasibility example would apply to operation scenario 2. As an alternative to installing additional pipeline capacity, an identified technology could be applied downstream of the bottleneck and provide the incremental natural gas supply needed on peak day demand events. For instance, the installation of a pipeline to parallel an existing for additional throughput may cost, as a rough rule of thumb, $1 million per mile including compression requirements. To gain the additional capacity required, a 100 mile pipeline installation would cost approximately $100 million, while a comparable volume of delivered natural gas from a cold compressed natural gas facility may cost $50 million in capital expenditures and a reasonable operating expense given the limited usage of the facility.

Technology Status

This section will discuss that status of technology or process development, commercialization plans, and additional research required to bring the technology to a commercially viable stage.

4.2. Project Outcomes

Conventional Gas Storage Deliverability Enhancement Technologies

Technologies included in this section are differentiated from alternative gas storage "dispersed"-based ones by their application to traditional underground gas storage assets. These are generally tools applied downhole, whether drilling or stimulation (enhance gas flow) focused, that provide incremental deliverability enhancement and maximize the efficiency of gas production from individual wells. Hydraulic fracturing and drilling techniques have been long established in the oil and gas industry. The information presented in this section is designed to describe relatively recent breakthroughs in these technologies that broaden their application or effectiveness. For example, hydraulic fracturing of traditional aquifer and depleted oil reservoirs (those typically found in California) have long been considered detrimental due to potentially compromising the integrity of the caprock. Recent, focused applications of hydraulic fracturing techniques have shown success at controlling vertical fractures. Excluding laser-based drilling, hydraulic fracturing and drilling techniques discussed in this section are commercially available through traditional service companies like Halliburton Energy Services, Schlumberger, or Baker Oil Tools. Pricing estimates and economic analysis can be obtained by contacting them directly.

Each of the technologies discussed in this section can be applied to California based natural gas storage wells and the depleted oil reservoirs utilized for natural gas storage.

Hydraulic Fracturing

Hydraulic fracturing is the most effective production stimulation technique for enhancing the production rate from oil and gas wells, and can be equally effective for delivery enhancement in gas storage wells. In hydraulic fracturing operations, a selected interval in the reservoir zone is isolated and fractured by application of an appropriate fracturing fluid under high pressure that exceeds the minimum in situ stress and the rock's mechanical strength at the target zone. A propping agent, usually sand, is also added to the fracturing fluid to prevent closing of the fractures after termination of fracturing operations and removal of the excess pressure. Hydraulically induced fractures are generally parallel to the direction of the in situ intermediate stress and vertical at depths greater than 1000 feet. High production rates resulting from hydraulic fracturing are due the extended surface area connected to the wellbore across which the pressure gradient causes the flow from reservoir rock to the high permeability fracture conduit.

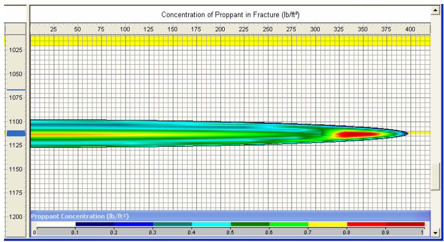
A key issue limiting application of hydraulic fracturing to gas storage wells is the possibility of unintended fracture height growth. For example, excessive fracturing pressure may cause fracturing of the caprock and migration of the storage gas to higher unconfined layers, or extensive downward growth linking the storage horizon to a water-bearing zone that may cause high water influx or flooding of the storage volume. As such, careless application of this technology to storage wells may cause serious irreversible damage to the reservoir. However, recent advances in fracture modeling and real-time fracture monitoring and diagnostics have made the precise placement of hydraulic fractures possible to the extent that these operations can be performed with a high degree of reliability and confidence.

The height of hydraulic fractures at the wellbore depends on the presence and strength of confining layers overlying and underlain by the reservoir rock. In cases of uniform formations (i.e., no confining layer, as would be the case for a small fracture in a massive sandstone reservoir), hydraulic fractures are circular planes with the height at the wellbore almost equal to their lateral extent. However, such cases are rare and at least one confining layer (the caprock shale) prevents the upward growth of the fracture causing it to attain an elongated rectangular shape extending to several hundred feet from the wellbore.

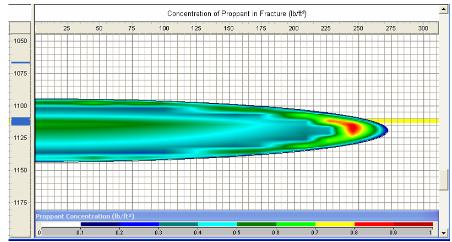
Figure 36 and Figure 37 exhibit the significance of rock properties in vertical fracture containment.

Figure 36 illustrate results of fracture modeling for a relatively shallow reservoir. Note that the lack of strong confining substrate (screen shot B) causes extensive upward and downward height growth causing the fracture to break out of the target zone (blue zone on left column). Figure 37 is the plot from analytic calculation of effects of stress contrast at the target boundary.

Figure 36 Vertical Fracture Containment Model Illustrations

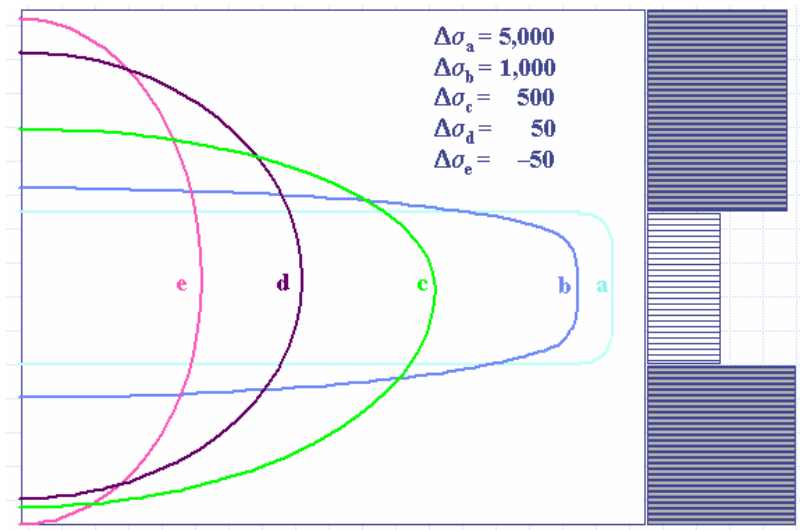


A. FIGURE 1 – FRACTURE MODEL USING HIGH CONFINEMENT



B. FIGURE 2 – FRACTURE MODEL USING MODERATE CONFINEMENT

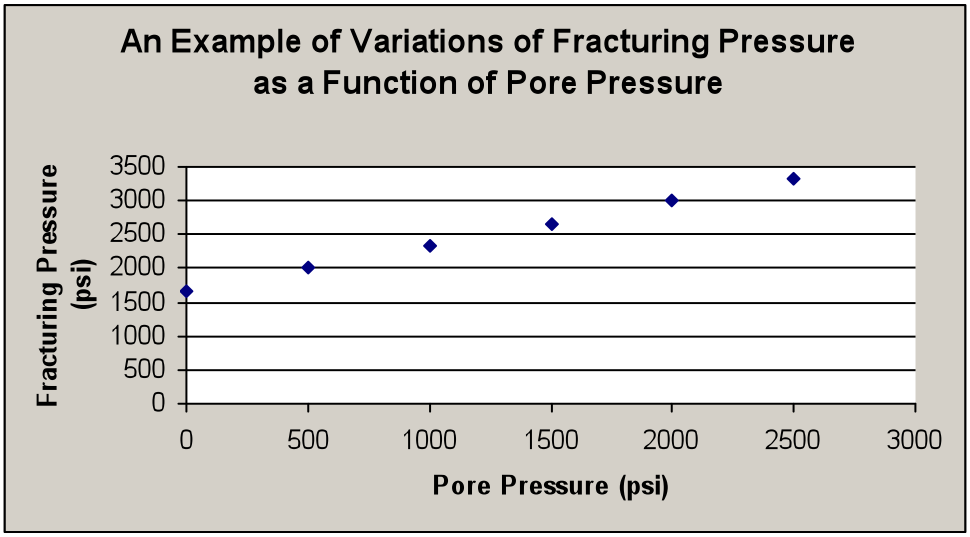
Figure 37 Effects of Stress Contrast on Fracture Height Growth



The following equation describes the pressure requirement for growth of hydraulic fractures. Note that the fracturing pressure is also a function of pore pressure and as such, the fracturing pressure that might be appropriate under high storage pressure prior to major withdrawal may be excessive for the same reservoir at lower pressure.

Figure 38 is graphic representation of the effects of pore pressure on fracture closure pressure.

Figure 38 Effects of Pore Pressure on Fracturing Pressure



As mentioned earlier, advanced fracture simulation for determination of appropriate fracturing pressure, rate, fluid viscosity and so forth has made it possible to design safe and targeted hydraulic fracture and real-time fracture monitoring can be used for monitoring and control of the process. The most reliable fracture diagnostic technique is seismic imaging of the fracture as it grows. In these surveys an array of triaxial geophones or accelerometers are placed in an observation well at a short distance from the treatment well to detect the seismic signals emanating from the fracture zone. The shear failure of rocks within and in the periphery of the fracture zone functions as miniature seismic source and generates seismic waves that are recorded by the wellbore receivers. Using the travel time and seismic velocity data obtained from check shots or perforation shots, the positions of seismic sources are calculated and plotted on a map and a cross section containing the treatment well. Figure 39 (Courtesy Pinnacle Technologies Inc.) provides a clear conceptual description of the technology.

Figure 39 Principles of Seismic Fracture Mapping

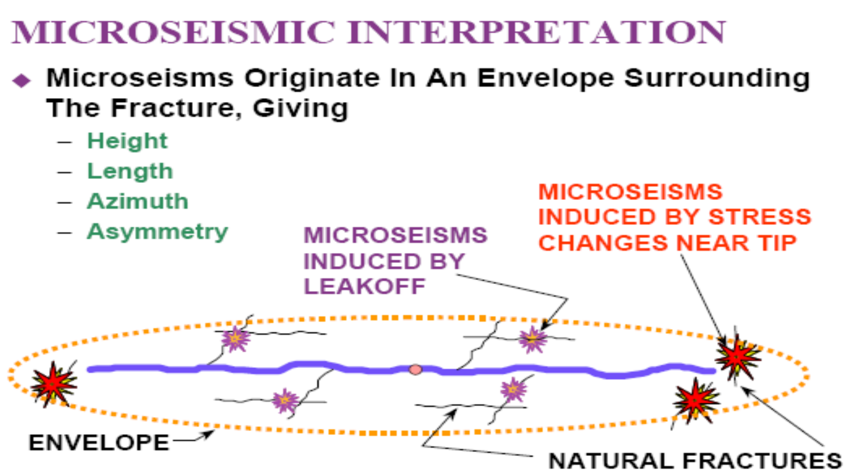
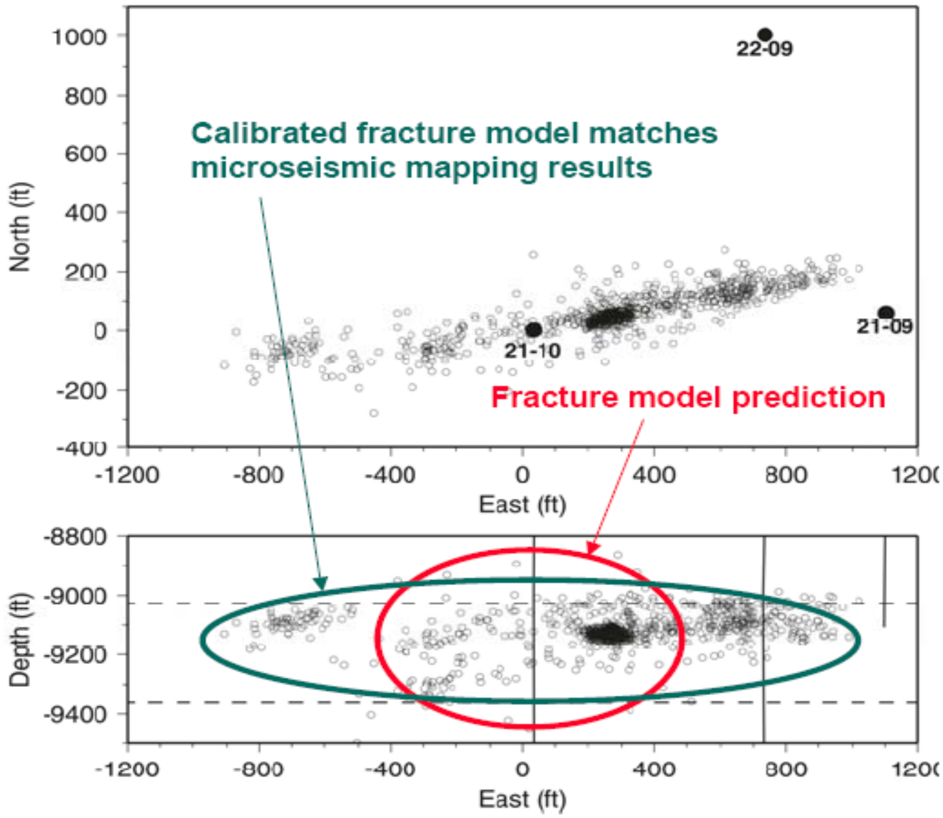


Figure 40 Microseismic Imaging Results from Fracture Modeling and Fracture Diagnostic Survey



Note that the incomplete nature of geologic and rock mechanics data causes smoothing and averaging in fracture simulations and therefore the modeling work must be verified and calibrated by results from fracture diagnostic surveys.

Another fracture diagnostic technique that has proven quite successful in the oil and gas arena is measurement of surface deformation during hydraulic fracturing and deduction of the fracture orientation from these measurements. In these surveys, a number of highly sensitive levels (tiltmeters) are deployed along one or more surface or borehole array and record the deviation from local vertical at the instrument sites during hydraulic fracturing. Results from these measurements are used to calculate the azimuth (and in some cases the extent) of hydraulic fractures.

Figure 41 (after Pinnacle Technologies) is a cartoon showing direction of ground deformations resulting from hydraulic fracturing and the principles of borehole tiltmeter surveys. The grids on

Figure 42 are contours of surface deformation resulting from vertical, horizontal and sub-vertical hydraulic fractures.

Figure 41 Principal Ground Deformations Resulting from Hydraulic Fracturing

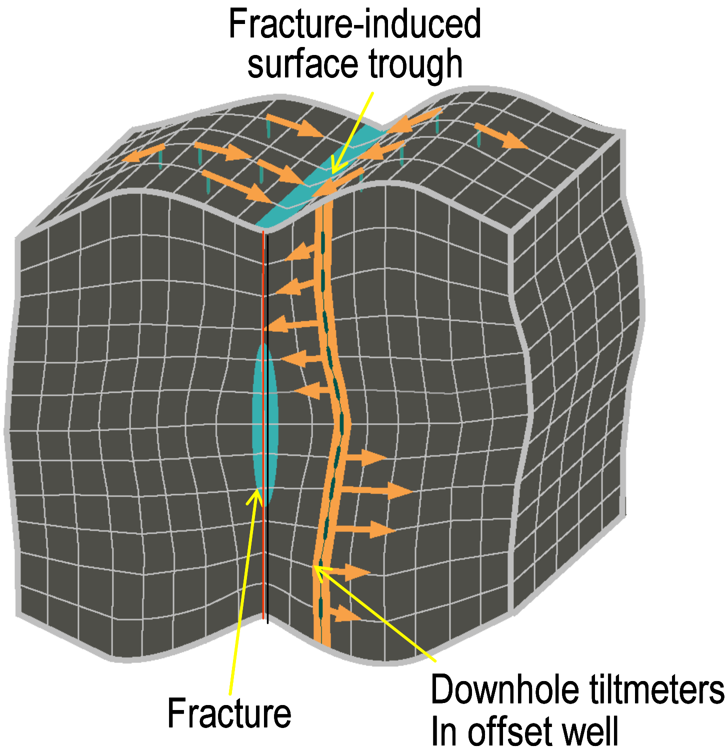
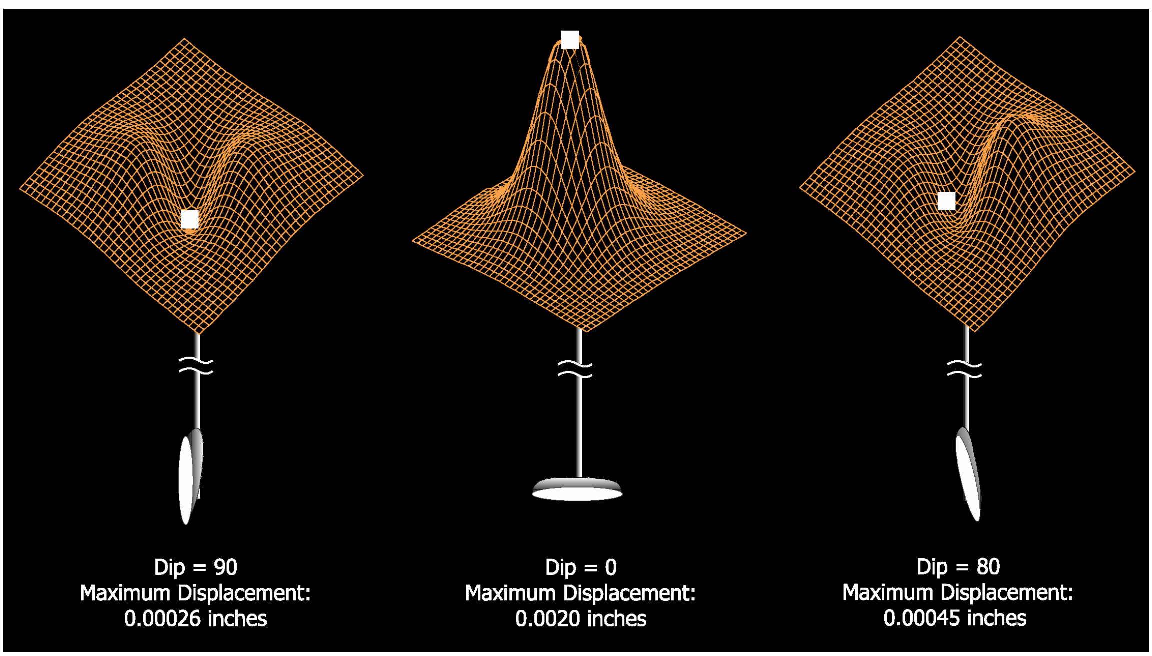


Figure 42 Ground Deformation Resulting from Vertical, Horizontal, and Sub-vertical Fractures



Technology Highlights

- Hydraulic fracturing can be used for enhanced withdrawal or injection rates. Because rates from fractured wells are several times that of un-fractured ones, treatment of existing wells could replace the drilling of new wells. While minimizing the environmental impacts through reduced footprint, this approach would substantially reduce the drilling and completion costs associated with additional capacity.
- In wells where deliverability systematically decreases due to near wellbore formation damage, creation of small hydraulic fractures should be considered as a safe and effective remedy.
- In cases of large fracturing operations, elaborate stimulation modeling and fracture diagnostic surveys are imperative for safe and reliable results.

Technology Status

Basic research on hydraulic fracturing has traditionally been conducted directly by service companies such as Halliburton, Baker Hughes, and Schlumberger. Hydraulic fracturing operations are mature and readily available for utilization. Recent research focus has been on monitoring and modeling (simulation) the process, and advancement of proppants for effective fracturing of rock formations. This research is also generally conducted by service companies and associated research institutions.

Economic Considerations

Hydraulic fracturing is a common production stimulation technique used by oil and gas producers worldwide. Historically, commerciality of many of oil and gas wells drilled in low permeability reservoirs depends on the effectiveness of hydraulic fracturing because un-stimulated production rate from these well is usually too low for economic capital recovery. For example, commerciality of gas wells drilled in the prolific Barnett Shale formation of Forth Worth, Texas depends primarily on the effectiveness of fracture stimulation. This is due to the production potential of these wells requiring investment recovery in less than six to eight months for the wells to be considered commercially viable.

As noted earlier, effectiveness of hydraulic fracturing is a function of reservoir porosity, permeability, reservoir pressure, reservoir thickness and lateral extent; and as such, development of a generalized economic formula for evaluation of fracturing effectiveness in terms of productivity enhancement is not possible. In practice, reservoir engineers calculate the expected effectiveness of hydraulic fracturing through simple reservoir simulation assuming various fracture length scenarios. Similar to many oilfield parameters, the data was always available in an after-the-fact sequence; i.e., fracture effectiveness is always known after the wells have been fracture stimulated. Naturally, this is true for the first well and once a number of wells are stimulated the data would be available for more reliable determination of optimal hydraulic fracturing and economic recovery.

Costs of hydraulic fracturing varies widely from field to field ranging from less than $100,000 to more than $1,500,000 depending on depth, volume and type of fracturing fluid and propants, required pumping horsepower; and logistical costs such as mobilization/de-mobilization , water transport and water discharge costs. However, because fracturing effectiveness is a function of fracture length, fracture designs are generally optimized by calculating the rate of return as a function of fracture length.

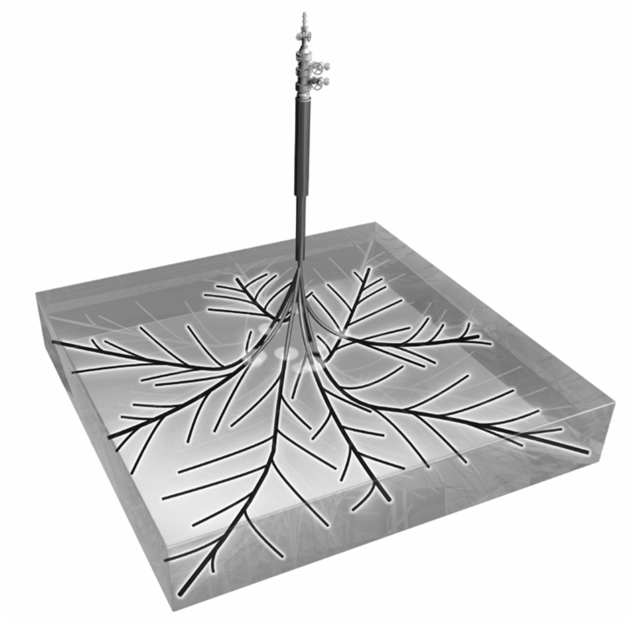
Note that in the case of fracture stimulation of depleted oil/gas reservoir storage wells similar to those in California, optimization of fracture stimulation must take a different approach. This is primarily because a net present value calculation as a function of cost would be meaningless given the cyclic nature of gas storage wells. The cost of fracture stimulation should be compared with the cost of additional wells that must be drilled and completed to match the delivery or injection capacity of a fracture stimulated well. Therefore, the point of diminishing return would be a point at which the cost of fracture stimulation equals that of a new well. With a typical vertically drilled well costing approximately $700,000 and yielding 5 MMcf/day flow, it provides a basis for determining the value of hydraulic fracture stimulation performance. Costs associated with linking the new well to the gathering system as well as additional wellhead and control units should also be taken into consideration.

Advanced Drilling Techniques

Recent advances in drilling technology offer new approaches to drilling gas storage wells. For example, extended reach horizontal wells would provide for high withdrawal rates particularly in cases of high permeability reservoirs where one long horizontal well can replace several conventional vertical wells. In particular, being equivalent to many vertical wells for injection and withdrawal rates, extended reach horizontal wells minimize the surface footprint considerably.

In addition, advances in measurement while drilling (MWD) and precision control of well trajectories have made it possible to drill several lateral wells from a single surface location (Figure 43), thereby contacting a large volume of reservoir as opposed to a single cylindrical volume centered on a vertical or horizontal well.

Figure 43 Schematic Design of a Multilateral Cluster Well



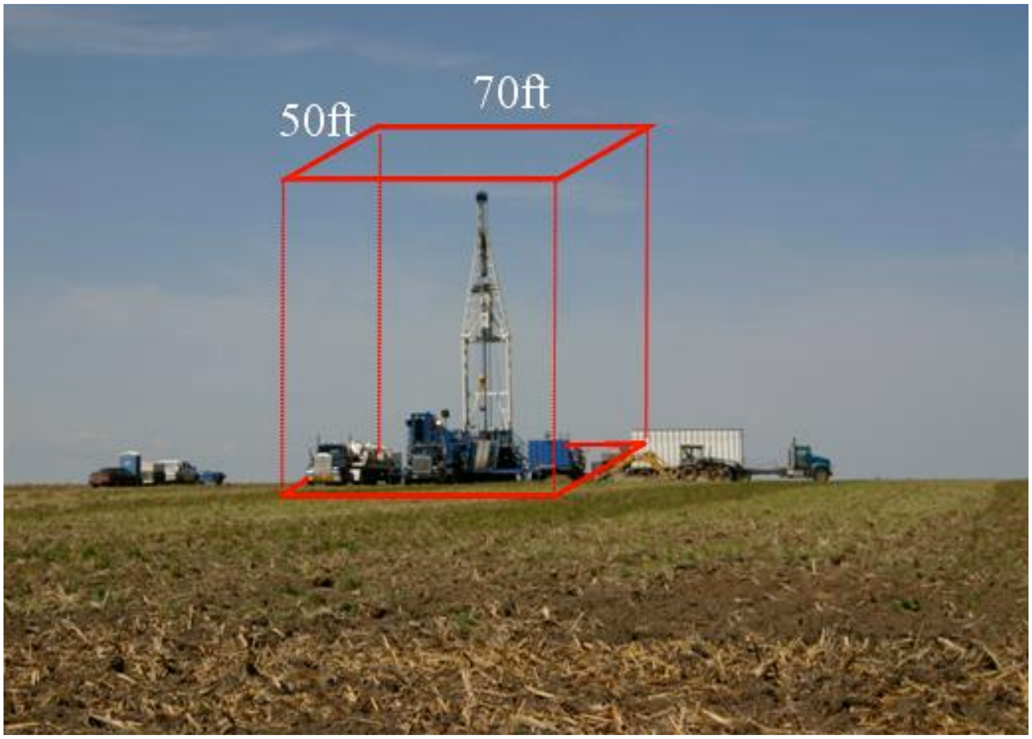
Because withdrawal from this multilateral cluster well configuration causes a rather low and distributed pressure differential, the technology offers two major advantages for storage operations by:

- Providing very high withdrawal rates without extreme localized pressure differential that may cause breach of the caprock, water coning or high lateral water influx.
- Requiring minimal surface footprint that could be a critical issue where the storage field may be in urban areas, or where surface disturbance may cause severe environmental or ecosystem damages. This is particularly important for natural gas storage wells located near urban SoCalGas and PG&E territories.
- Multilateral cluster storage wells do not necessarily require the sophisticated downhole completion equipment and therefore often results in less complicated remote manipulation of downhole valves.

Another advanced drilling technology applicable to storage fields is the recently developed micro-hole drilling system using small coiled tubing rigs (depth fields, or approximately 3,000 to 5,000 feet.

Figure 44). The footprint of these truck mounted rigs barely exceeds 50 by 70 feet making them ideal for work-over and remedial operations as well as drilling and completion of in-field wells in shallow to moderate depth fields, or approximately 3,000 to 5,000 feet.

Figure 44 A Microhole Drilling Rig on Location



*Source – GTI Catoosa Test Facility, Tulsa, OK,

Although the maximum drilling depth for these rigs is about 5000 feet, they can also be used for work over (well remediation) of deeper wells and drilling of shallow instrumented observation wells or wells for venting or collection of shallow gas seepages. Portability, small footprint, minimal contained discharge, and low operating cost make these rigs ideal for working around the California gas storage fields near urban areas as well as for environmental concerns.

Technology Highlights

- Extended reach horizontal wells provide for high withdrawal rates needed for meeting the peak demand. These wells would be ideal for cases where the storage reservoir rocks are relatively thin.
- Cluster drilling offers an environmentally preferred option as it minimizes the surface footprint while providing for high production rate.
- Micro-hole rigs are ideal for work over and remedial operations. They would be also preferable for drilling and completion of wells for storage reservoirs down to 5000 feet.

Technology Status

The drilling techniques discussed are mature technologies and readily available for implementation by service companies and drilling contractors. Research continues in each of the drilling techniques to improve the drilling process measurement and controls, resulting in extension of reach and control in both horizontal and multi-cluster wells. Coiled tubing technology is also available from service companies and is commonly used in shallow drilling, remedial work-over, and completion applications. Reach, versatility of application, and measurement continue to be improved through research efforts and made available on the market.

Economic Considerations

Cost advantages of multilateral and cluster wells are primarily due to the sharing of the vertical section between two or more wells, use of common wellhead equipment and control units, and a single extension to gathering system. In general, multilateral and cluster wells are economical in the case of deeper reservoirs, particularly if multiple strings of casing would be required. This is due to the fact that drilling of horizontal wells is generally more expensive than vertical wells and the cost may potentially exceed the benefits depending on drilling conditions, such as depth, geology, and pressure conditions. On average, costs associated with horizontal well drilling can range anywhere from 75% to 200% higher than individual vertical and deviated wells, which can also vary widely from approximately $400,000 to $1,000,000 +. Drilling of multiple low-angle deviated wells from a single drilling pad could also be an economically attractive alternative to horizontal wells for areas with reasonably thick storage reservoir. Selection of multilateral and cluster drilling should be based on the overall cost analysis where all cost elements including drilling, completion, wellhead equipment, and gathering system are analyzed.

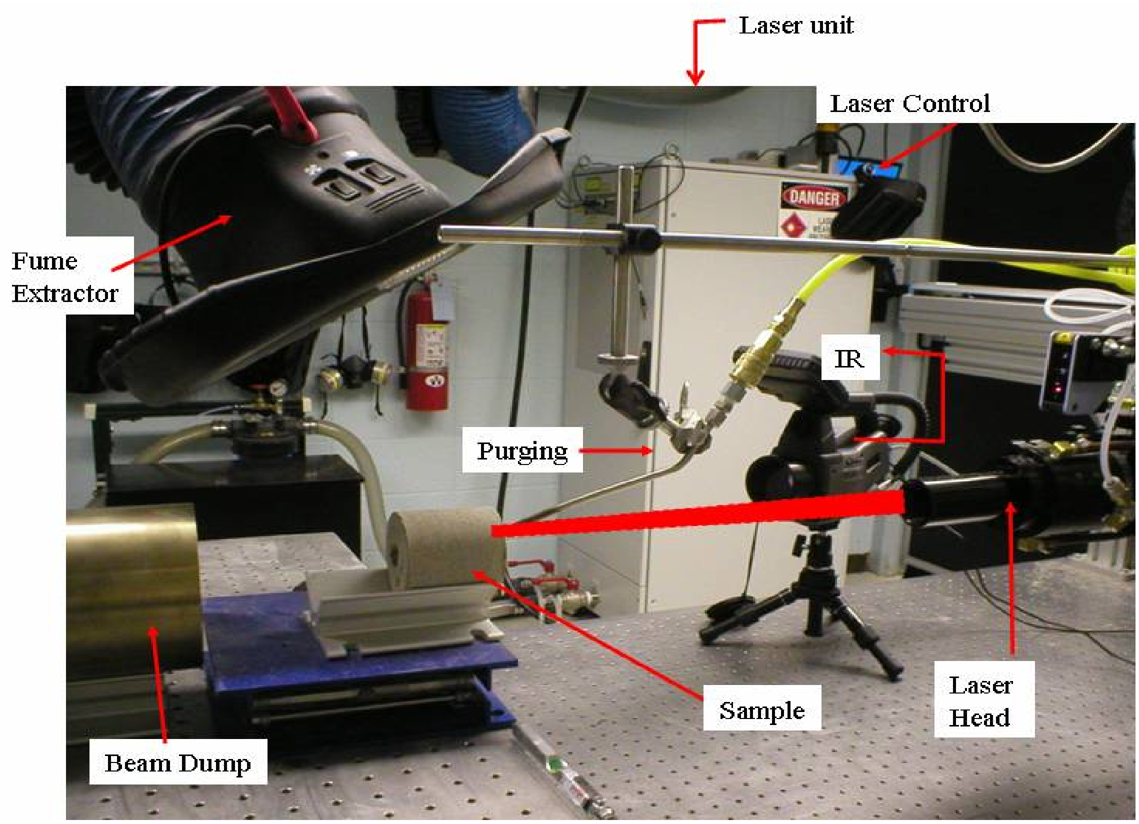
A second category of cost related parameters influencing the economic decision on utilizing multilateral and cluster drilling technology could be minimization of access roads and drilling pads as well as other environmental impacts associated with surface disturbance caused by drilling sites and gathering system. Specifically, cost savings due to the use of a single drilling pad servicing two or more wells could be a deciding factor. This is particularly attractive in California given the proximity to urban areas as well as aggressive environmental standards.

Drilling with Microhole technology rigs are typically 25% to 50% lower than traditional drilling and workover rig costs. This is largely due to a reduction in surface costs, smaller rig utilization, and performance savings by minimizing trip in and out time and related costs. Economic analysis and drilling estimates pertaining to specific conditions can be obtained from local service companies and drilling contractors.

Laser-based Drilling and Completion Technology

One of the more promising drilling and completion technologies on the horizon that is expected to be commercially available in the near future (< 10 years) is downhole laser technology. Application of laser technology to well drilling and completion involves the delivery of high intensity photonic energy to earth material or casing. GTI, with support from the Department of Energy, pioneered the research and development in this field and research results have been very promising for certain operations such as casing perforation and cutting of windows in the casing for sidetracking and cluster drilling. Figure 45 is a photograph of GTI's laser laboratory showing all essential equipment and their functionality. This laboratory is in essence a bench version of the required equipment that would be reconfigured for wellbore environment. The principal equipment include the laser generator, the fiber carrier, laser head assembly, the cooling system, and the control unit for laser operations as well as the robotic movements of the laser head. In field operations, the laser energy would be carried to the work face via special optical fibers passing through a combination of lenses for collimation, focusing, and other optical manipulation.

Figure 45 GTI Laser Laboratory



Depending on the laser intensity and lasing time, laser-rock interaction occurs at a continuum ranging from simple heating of the rock to its vaporization as follows:

- Low energy level: heating that may cause dehydration of clay particles and development of microfracture because of differential expansion of different rock particles.
- Intermediate energy level: heating, dehydration, micro-cracking, and spallation due to differential expansion.
- High energy level: melting and vaporization of rock materials.

Relative to natural gas storage fields in California, the more immediate application of laser technology would be remediation of near wellbore formation damage through spallation and heating, creation of longer perforation tunnels for better communication between the wellbore and reservoir, and cutting of windows in casing for sidetracking or drilling of horizontal or cluster wells.

Figure 46 Sand Grains Before Lasing

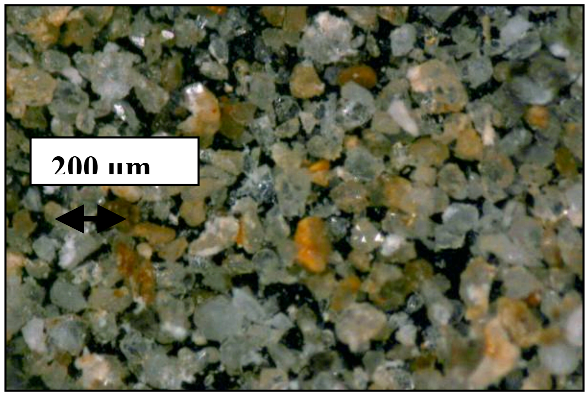
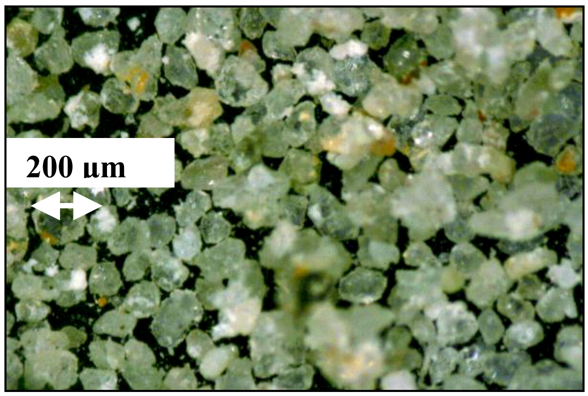


Figure 47 Sand Grains After Lasing



Effects of differential thermal expansion can be seen by comparing the physical characteristics between pre- and post-lased grains. Figure 46 shows a magnified view of loose grains from Berea sandstone, carefully prepared and extracted from the rock sample before lasing. The grains observed in this sample are well sorted, and the shapes of the grains are round and sub-round. Figure 47 shows the same magnified view of sandstone grains collected following their spallation and ejection from the rock sample during lasing. Note the angular broken grains and poor sorting due to stresses imposed by thermal expansion and cooling. This indicates that spallation is causing the breaking of siliceous cement matrix as well as the sand grains. Chemical changes to the rock matrix occur as black organic material and other fragments present in the sandstone matrix dissociate, dehydrate, decompose and/or vaporize at temperatures lower than that required to melt quartz. The Berea sandstone sample was composed of less than 5% of these types of material by volume.

Laser spallation can be readily applicable to openhole storage wells where deposition of higher hydrocarbons, iron hydroxide, rust, and other materials decreases the permeability and production rate. A high energy laser would cause the decomposition of organic materials and rust and loosening spallation of the formation. This effectively removes a thin layer (skin) from the well wall. Considering the depleted oil and gas wells in California are relatively dry, liquid purging would not be required and nitrogen purging can be readily applied.

Creation of long, clean, and wide perforation tunnels is highly desirable for completion of storage wells. Laser perforation offers an advantageous alternative to traditional shaped charge and bullet perforations for the following reasons:

- The length of perforation tunnels would be controllable and long tunnels can be created.
- Unlike shaped charges that reduce the permeability because of debris and deposits (pulverized zone), lasing would increase the tunnel wall permeability through spallation and dehydration of clay particles.

Figure 48 shows two versions of perforation channels in Berea sandstone. The tunnel on figure A was created by application of collimated beam and figure B is a cut view of a conical shape tunnel lased by a focused beam.

Figure 49 is a perforation tunnel in limestone using variable focal length. The schematic drawing on Figure 50 shows the optical setup for these techniques.

Figure 48 Examples of Perforation Tunnels Using Collimated and Focused Beams

A B

Figure 49 Perforation Tunnel in Limestone Using the Variable Focal Length Technique

Figure 50 Schematic Diagram of Optical Setup for Collimated and Focused Beams

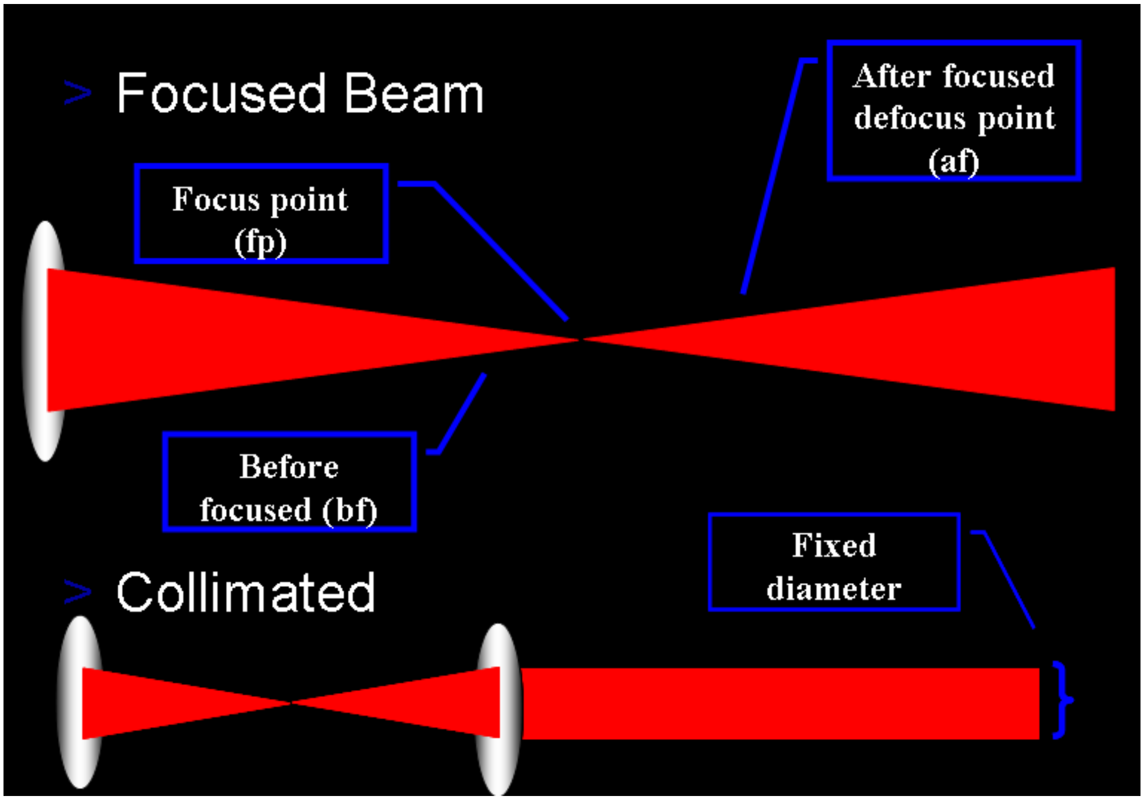
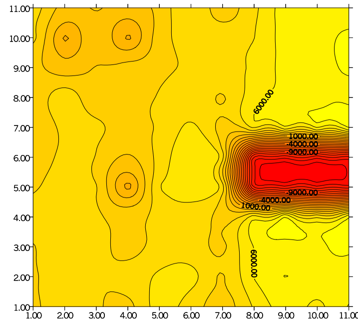


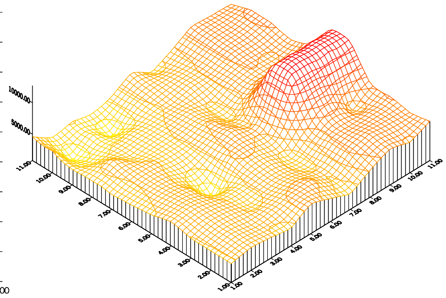
Figure 51 shows the permeability increase resulting from lasing a short tunnel in Berea sandstone. A is a photograph of the tunnel and was taken after the sandstone block was sectioned at the center of the tunnel. B and C are 2-D and 3-D permeability contours prepared from permeability measurements on a dense grid on the backside of the block. Note that highest permeability values (illustrated in red) are from the section of the block containing the tunnel and extend laterally in a direction normal to the tunnel axis.

Figure 51 Photograph of a Sectioned Block After Lasing (A) and 2-D and 3-D Permeability Contour Maps (B and C) Prepared from Measurements on the Backside of the Block

A



B



C

Other applications of downhole laser energy include cutting slots in the production casing or liner as well as opening of windows for side tacking, horizontal drilling, or cluster well drilling. Presently all slotted liners are pre-cut and no technology for slotting the tubular in the wellbore is available. In those conditions where the use of pre-slotted liners may cause concerns because of wellbore damages or undesired communication (e.g., in the case thin bedded reservoir layers), accurate positioning of the slots would prove safe and effective. Relative to downhole slotting, the laser application can continue after a slot is formed to create extended tunnels from the slot well into the formation.

Technology Highlights

- Downhole laser technology offers several effective techniques for storage well completion and efficient remediation:
- The formation face of openhole gas storage wells can be treated for removal of deposits and enhance deliverability.
- Laser perforation can provide long and clean tunnels that would be more effective for high rate production. These tunnels could be a few feet long substituting for short radius laterals, and
- Downhole laser energy can be applied for in situ slotting of production liners with extended tunnels.

Technology Status

GTI, in collaboration with the Department of Energy (DOE) and Halliburton Energy Services (HES), have completed proof-of-concept investigations and research through bench scale perforation applications and experiments. These included utilization of various military lasers as well as high power industrial lasers on over two hundred samples including shale, limestone, and sandstone. Additional experiments have been conducted using lower cost, high powered fiber lasers developed by IPG Photonics Corporation.

Further research is being proposed to conduct pilot scale downhole in-situ experiments on both perforation and casing cutting operations.

Economic Considerations

Though lower cost, high power fiber based lasers are being manufactured and are applicable to gas storage drilling, stimulation, and completion operations with promising results, economic viability of this technology has not been proven at this time. Early estimates indicate a minimum of 200% to 300% higher costs than conventional applications. Further development of the technology will be necessary to fully explore potential application costs.

Summary of Technologies

The following table summarizes the conventional gas storage deliverability enhancement technologies discussed in this section.

Table 10 Conventional Gas Storage Enhancement Technology Summary

TECNOLOGY	OPERATIONAL BENEFITS	ECONOMICS	TECHNOLOGY STATUS
Hydraulic Fracturing	• High deliverability • Potential substitute for new well • Longer term stimulation technique	• $100k - $1.5 M, depending on well parameters	• Improvements in vertical fracture containment • Viable for gas storage • Mature technology – available from local service companies
Horizontal/Cluster Drilling	• Very effective on thin pay zones • High deliverability/low pressure differential • Small footprint – environmentally friendly	• Shares well head and surface equipment • 70% to over 200% higher costs than vertical well	• Mature, but continuous improvements in downhole controls and MWD required • Drilling contractors widely available
Microhole Drilling	• Small footprint drilling rig – environmentally friendly • Coiled Tubing application – cost effective	Generally 50% less costly than traditional drilling rigs	• Base coiled tubing technology available from local service companies • Improvements required in depth – limited to approximately 5,000ft.
Laser Based Drilling and Completion Technology	• Flexibility of application – drilling, completion, stimulation • Long and clean perforation tunnels – no crushed zone • In-situ slotting of liners and window cutting • Formation face treatment	Cost prohibitive at this point in development cycle – early estimates indicate 200% to 300% higher costs than conventional	• Requires additional research focusing on cost effective, powerful laser development and field demonstration • Laser technology currently being developed by multiple companies and institutions – Halliburton, GTI, Argonne National Laboratory • Laboratory demonstrations successful

Alternative Natural Gas Storage Technology Review

The storage of natural gas, in various "vessels" (including line packing) can occur at a variety of temperatures and pressures, ranging from LNG as the densest form, to moderate pressure (warmer) gas storage, or line pack, in local pipelines, with moderately dense high-pressure (warmer) underground natural gas storage. California has multiple forms of gas storage, with the exception of those geologically constrained, (ie. cavern storage), or LNG peakshaving facilities facing siting issues.

Most large-scale storage systems operate within "cycle constraints", where the injection and withdrawal periods are limited by many factors, both operationally and by seasonal demand. These existing models in California or serving California, including underground natural gas storage, are traditional assets that have limited flexibility due to injection limitations. Due to the nature of demand in California, with multiple peak demand periods, increasing flexibility is required to satisfy growing demand and overcome those potential local infrastructure limitations explored in Section 3.0 of this report.

Adsorbed Natural Gas

Adsorbed natural gas storage was primarily investigated in the 1980's and 1990's as an alternative to compressed natural gas (CNG) storage for natural gas vehicle (NGV) applications. CNG storage at pressures of 3000 and 3600 psi became industry standards. The cost and weight of the vehicle storage cylinders and cost of the associated fueling equipment were identified as economic issues constraining the NGV market acceptance. Although advances in ANG storage were achieved, the technology was not developed sufficiently for commercialization. By the late 1990's, governmental support for NGV research and development began to decline and ANG development for NGVs terminated. There has been renewed interest in ANG over the past eight years as advancements in adsorbent materials were achieved. Organizations such as Advantica, Energtek, All-Craft (led by the Missouri-Columbia University), Honda, BASF, and GTI have recently contributed to the advancement of the technology and pilot scale pre-commercialization demonstrations planned in the near future.

Technology Description

Adsorbent storage technology is based on the principle that the amount of natural gas stored in a pressurized cylinder is greatly enhanced by placing an activated carbon substrate inside the cylinder. This principle is valid up to about 1800 PSIG, after which the carbon becomes a greater impediment to storage capacity than it is capable of providing through adsorption. The performance of the adsorbent material is a function of three variables:

- Methane adsorption capacity (which is itself a function of surface area and number of adsorption sites per unit of surface area),
- Packing density of the adsorbent, and
- Thermal conductivity of the adsorbent.

Thermal conductivity is important because significant heat is generated from adsorption of methane (4 Kcal per mole) and heat is required for desorption. These temperature swings resulting from the exothermic and endothermic reactions to adsorption and desorption of methane during fast charges and discharges impede the ultimate storage capacity of the adsorbent system. For example, a quick charge from atmospheric to 500 PSIG would result in only about 80% of the amount of gas stored as would occur in a prolonged charge that allows the heat of adsorption to dissipate. Adsorbents with greater thermal conductivity dissipate the heat of adsorption more rapidly.

Packing density of the adsorbent is a significant factor because it determines the physical mass of adsorbent present in the cylinder. Higher adsorbent density creates a larger storage capacity, although an offsetting effect may be a reduction in the rate of flow of methane through the adsorbent bed at higher packing densities and an increase in the amount of methane left in storage at atmospheric pressure[3].

Adsorption in Microporous Substrates

Adsorption in microporous media is in many ways different from that on a plane solid surface because the size of the pores (those having diameter less than 2 nm) is only 3-5 times that of the adsorptive molecule. Both nitrogen and methane have comparable-sized molecules at 0.3-0.4 nm, for example. Because of this, the force fields responsible for the adsorption process operate on the adsorbed methane molecule in a very enhanced way and there are more molecules held in the adsorbed state for a given equilibrium pressure compared to that on a plane surface[4].

Volumetric Storage

Volumetric storage (v/v) is the volume of natural gas that can be stored per unit volume of carbon adsorbent. Although units such as cubic feet of gas per cubic foot of carbon or liter/liter have been assigned to it, it is strictly dimensionless. It is necessary to state the conditions under which the storage was measured. Typically, for NGV applications, the conditions are room temperature, defined as 25°C (298 K) and 500 psia (34 bar)[5].

Carbons from Cellulose Sources

In the early 1990's, several sources of carbons were investigated for producing dense carbons with a very high potential for storage of methane on the criterion of volume gas / volume adsorbent. The most promising turned out to be those from coconut shells and from peach pits. The raw material was ground, and in some cases pressed into monolithic disks, and then pyrolyzed to produce the carbon for evaluation. The pyrolyzed carbons were activated by selective burn-off in steam or carbon dioxide. Surface areas of over 2500 m^2/g resulted and the best carbon samples had a predicted storage of greater than 120 v/v, provided that void-free monoliths could be made from them[6].

---

[3] Gas Research Institute, GRI-90/0139, Task 3 Topical Report (March 1989-April 1990), "Economic Analysis of Low-Pressure Natural Gas Vehicle Storage Technology", April 1990, Pages 29-30

[4] Gas Research Institute, GRI-95/0068, Final Report, "Absorbed Natural Gas (ANG) Research conducted by Atlanta Gas Light Absorbent Research Group (AGLARG)", June 1994, Page 11

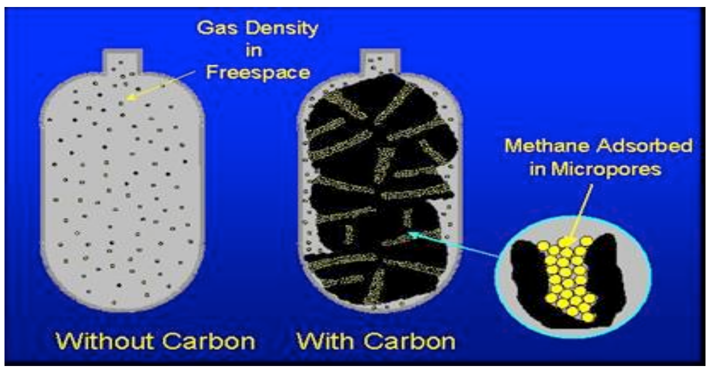
[5] GRI-95/0068, Page 19

[6] GRI-95/0068, Page 2

Carbons from non-Cellulosic Sources

Also in the 1990's, the possibility of synthetic sources for carbons were explored and the pyrolysis of poly(vinylidene)chloride (PVDC) produced carbons of higher capacity for storage, above 170 v/v. The PVDC resins were easily pressed into coherent disks that maintained their integrity on pyrolysis and although the surface area was only about 1000 m^2/g, the absence of macro and mesopores gave the disks a high density that led to the high storage values observed. The micropores were very narrow which led to considerable amounts of gas being retained when pressure was reduced to atmospheric. Careful selective activation widened them sufficiently without making concomitant mesopores, so that >150v/v of methane were obtained[7].

Figure 52 ANG Process



This process is illustrated in

Figure 52, where a storage vessel is filled with an appropriate adsorbent material (activated carbon), gas molecules are adsorbed in the adsorbent micropores at a much higher density than in the compressed phase of the same vessel at equivalent pressure. This has the effect of producing the volumetric enhancement over pressurised storage as described above.

The ANG process is particularly beneficial at medium pressure, for example 500 psig, where a volumetric enhancement of 2 to 4 times can be achieved, depending on the type of activated carbon used.

Figure 53

Figure 53 shows a typical storage capacity for a low-cost activated carbon that is widely available commercially (Carbon 1) and a specialized, but high cost material (Carbon 2). The storage capacity is expressed as v/v – volume of gas stored per volume of vessel capacity.

Carbon 1 is a typical commercial grade carbon that is being manufactured in bulk quantity for a range of industrial applications, though tailored to natural gas use. A delivery performance of

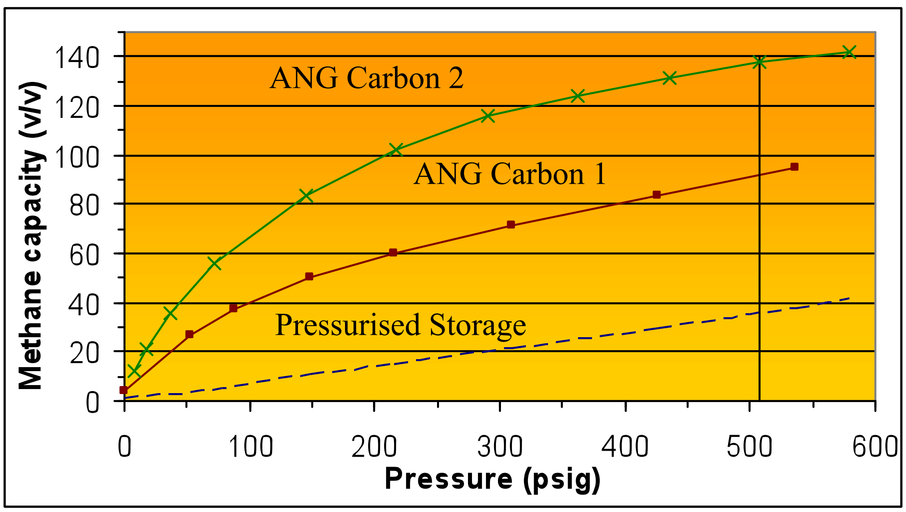
[7] GRI-95/0068, Page 2

90 v/v at 500 psig storage pressure and better than 125 v/v at 800 psig can be achieved with this carbon after further treatments, as recently claimed by Energtek. The current cost for this carbon ranges from $2.00 to $3.50 per kg.

The cost of carbon materials tends to increase disproportionately to performance for storage capacities above this. This means that the carbon giving 150v/v at 500 psig would currently cost of the order of 10 to 20 times that of the 90 v/v carbon materials.

Carbon 2 is a highly-activated material such as that developed within the Atlanta Gas Light Absorbent Research Group AGLARG program. As indicate earlier, this can give up to 150v/v natural gas stored at room temperature at 500 psig. However, it has only been produced in small quantities for on-board storage of natural gas on vehicles and is unlikely to be cost effective for large-scale network storage application at this time, although large scale manufacturing would bring this cost down. Manufacturing of adsorbents of this performance level at competitive cost is potentially viable in a 15-year time horizon.

Figure 53 Examples of ANG Storage Capacity



ANG storage requires a low-pressure discharge point to deliver the maximum working capacity, ideally to 15 psig or lower. Although this also applies to other pressurized storage systems, the non-linear uptake and delivery at lower pressures makes this a particular characteristic of ANG. This makes ANG an attractive storage solution for low-pressure distribution networks.

Operational Feasibility

The possible applications of ANG range from small-scale on-board fuel storage for natural gas vehicles to strategic local network storage and large-scale transportation for natural gas. For the purpose of this research, further discussion will focus on larger scale applications and in particular those operating scenarios outlined in Section 4.1.3 Operational Feasibility. A general description of utilizing ANG in these applications is as follows:

Strategic distribution/transmission network storage (Operating Scenarios 1&2).

- The gas storage capacity could range from 100,000 scf to 3 MMcf per vessel. This is further expanded in the operating scenarios below.

Mobile storage supplying to non-pipeline areas (Operating Scenario 3).

- ANG mobile storage vessels take gas from high-pressure pipeline, and discharge into a low-pressure local distribution network that is not connected to the gas grid. Restricted by the maximum pay load on the road (typically 30 tonnes), the gas storage capacity is limited to 150,000 scf per truck. This technology is readily available on the market today and is therefore not covered in more detail in this report.

Operating Scenarios 1&2

Storage capacities for operating scenarios 1 and 2 are significantly larger than typical ANG applications. To satisfy these parameters a bank of ANG vessels would be required. Multiple storage pressure and storage capacity configurations will be examined in this analysis.

Two potential options for ANG storage pressure in operating scenarios 1 and 2 are:

- Gas is stored at the network pressure (i.e. 300 psig in Case 1 and 500 psig in Case 2) to remove the need for inlet compression.
- Gas is stored at approximately 850 psig with inlet compression. This is the typical optimum storage pressure according to application experience, on a cost-per-unit-storage basis for a commercial-grade carbon. Beyond this pressure, the volumetric enhancement for ANG system (over compressed storage at the same pressure) drops while capital expenses increase for the higher-pressure vessel and equipment.

The storage capacity of the ANG vessel depends, among other things, on the range of the working pressure cycle. Despite the better volumetric enhancement in the 100 to 600 psig range, it is crucial for the intended applications to ensure a high unit storage capacity to provide the large storage requirements and resulting deliverability. While ANG would normally be assumed to provide storage at highest prevailing pipeline pressure, for these scenarios we recommended utilizing higher pressure storage with inlet compressors to minimize vessel numbers and associated capital expenditures.

The estimated unit storage capacities at these pressures are shown in Table 11. The second storage pressure option (500 psig) is preferred as a measure to reduce the number of high-pressure vessels required, while still maintaining the safety and operational advantages of medium-pressure operation. This assumes that the gas is removed from storage to a low pressure and compressed back to pipeline pressure. The difference for the 850 psig case is the pre-compression into the ANG storage medium.

Table 11 Estimated Unit Storage Capacities for ANG System

Storage Pressure	300 psig	500 psig	850 psig [a]
Storage v/v			
Commercial-grade carbon	65	90	125
High-performance carbon (e.g. AGLARG carbon)	100	150	180

[a] With inlet compression

Storage Vessels

The ANG storage vessels are essentially a series of high-pressure carbon steel cylinders (vertical or horizontal) filled with activated carbon.

The proposed single cylinder dimension and capacity appropriate for these operating scenarios are:

- Dimension = 12 ft (diameter) x 230 ft (length)
- Volume = 25,500 ft^3

An empty cylinder is estimated to weigh about 518 tons, which can present logistical challenges for installations. As these cylinders are too heavy to be transported by road, they can either be shipped in by sea (if a nearby port and facilities are available) or have the final assembly done on site.

The desired discharge flow rates should be incorporated into a final ANG system design. There is no limitation in the ability of the ANG system to meet the flow rates specified in these operating scenarios. Any potential discharge flow rate limitations would be a function of valving or mechanical operation of the system, not the inherent performance of the storage medium. Table 12 provides an estimate of the required cylinders to meet the storage capacities identified in operating scenarios 1 and 2. The 850 psig storage pressure option is explored in this particular example.

Table 12 Estimate Number of Cylinders for Operating Scenarios 1&2 @ 850 psig

Operating Scenario	Storage Capacity	Commercial-grade Carbon		High-performance Carbon	
		No of cylinders	Est. area [b]	No of cylinders	Est. area [b]
OS 1	56 MMcf	18	216 x 500 ft^2	13	312 x 250 ft^2
OS 2	140 MMcf	44	528 x 500 ft^2	31	384 x 500 ft^2

[b] For cylinders only, assuming a single-diameter (12 ft) spacing between cylinders

About 156,000 ft^2 of land would be required for ANG storage for operating scenario 1 even with the high-performance carbon due to the large storage requirement. Allocation and utilization of this large area of land in California could be difficult and prohibitive in implementing a system of this magnitude. Stacking of cylinders could reduce the land requirement by up to half if this if acceptable, though as indicated above handling this large number of cylinder could prove logistically challenging.

Main Process Equipment

ANG technology relies on sequential adsorption and discharge (desorption) of gas in a vessel filled with activated carbon according to demand. An ANG system suitable for the intended applications contains the following key components:

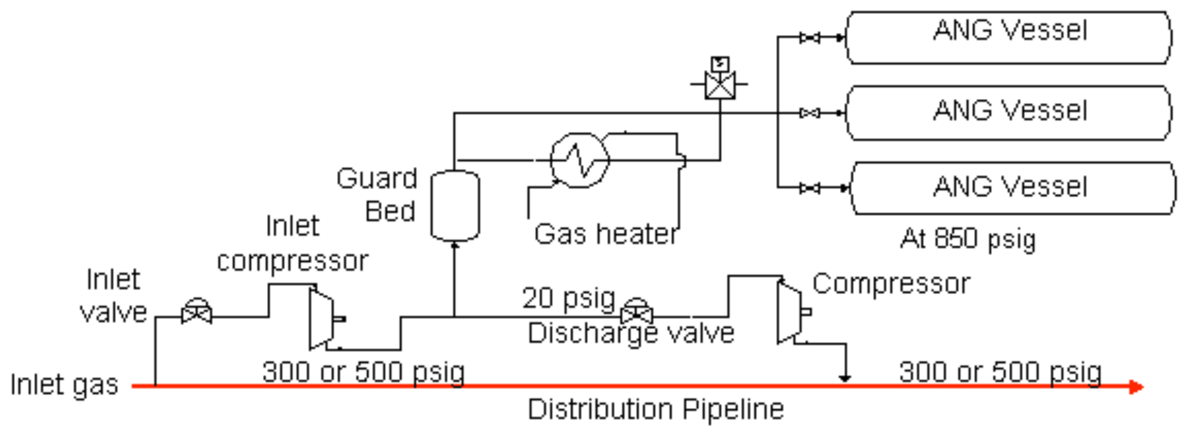
- *Guard bed* - Pre-adsorption vessel removing higher hydrocarbons (C5+) and odorants which will cause degradation of the main adsorption bed.
- *ANG storage vessels* - Packed with activated carbon and storing gas at about 850 psig.

- *Adsorbents* - Different types of activated carbon are selected for the guard bed and main bed for their preferential adsorption of various components.
- *Gas heater* - To allow the desorption of higher hydrocarbon and odorants on the guard bed back to the gas during discharge phase for gas quality assurance.
- *Inlet compressor* - To compress the inlet gas from the respective network pressures to a storage pressure of approximately 850 psig.
- *Discharge compressors* - Low-pressure discharge is essential to maximize the working capacity of ANG storage. Compressors are installed to increase the outlet gas pressure to the respective required pipeline pressure.

Storage pressure is proposed to be 850 psig with inlet compression. The ANG vessels are discharged to as low as 20 psig to make full use of the ANG stored capacity, and the gas is subsequently compressed to meet the respective network pressure requirements. Large compression duty is required for this application, therefore is not the ideal condition for ANG storage due to increased capital expenditures.

Components such as odorants and higher hydrocarbons (C5+) would be more strongly adsorbed and difficult to remove completely. In long term applications, these will reduce the carbon storage capacity and therefore need to be removed prior to the storage vessels. A small pre-adsorption vessel, or guard bed, is installed for this purpose. On the discharge cycle, adsorbed components are recovered from the guard bed by heating the out-flowing gas to ensure that the pipeline specifications are met throughout the ANG operational cycle. A schematic of this system is shown in **Error! Not a valid bookmark self-reference.**.

Figure 54 Schematic of Typical ANG System



Process Safety

Extensive safety studies and risk assessments on large-scale ANG storage system have been carried out by Advantica, an England based company currently developing ANG technology for commercial application. Four main hazards were identified and analyzed for the ANG system:

- Catastrophic vessel failure
- Carbon ejection from pressure relief valve
- Vessel failure due to flame impingement
- Pipeline failure

Many hazards associated with ANG appear to be reduced in comparison with typical CNG systems at similar pressure, due to the nature of adsorption. These include:

- Reduced peak gas dispersion distances
- Reduced jet length in the cases of ignited release
- Emissive power and radiation levels are not increased
- The cooling effect of the desorption process limits peak flow rates
- For an equivalent storage capacity, the ANG storage pressure will be lower, giving a further safety gain

A potential hazard with higher associated risk than CNG storage was identified to be the possible carbon ejection from the pressure relief valve when it is operated. Delayed ignition at some distance could occur following the projection of carbon particles. Mitigation measures such as an external carbon "retainment" unit will greatly reduce the carbon ejection distance and improve on safety distance required.

Economic Feasiblity

ANG technology for gas network storage has yet to be applied in any commercial applications. Therefore, the capital expenses (CAPEX) and operational expenses (OPEX) reviewed in this report are based on information supplied by leading ANG technology developers, Advantica Inc. in particular.

CAPEX Estimation

There are four main components that determine CAPEX associated with an ANG network storage system as described in this analysis:

- *ANG vessels* - For a given storage requirement at 850 psig, the installed CAPEX per unit storage (e.g. US$ /MMcf of gas) for ANG vessels is estimated to be approximately 90% of that for CNG storage at 3600 psig. Despite its operating pressure being only a ¼ of the CNG storage pressure (therefore thinner vessel wall thickness), more vessels are required due to its lower storage density (125 v/v vs. 250 v/v for CNG). This offsets potential savings from the less costly, lower-pressure vessels. However, it should be noted that where very large pressure vessels are used for compressed gas storage on networks it is very rare that they are specified for pressures greater than 1000 psig, and their capacity at this pressure is less than ANG enabled vessels.
- *Activated carbon* - A commercial-grade carbon has been assumed for this analysis. The estimated cost for this carbon is currently approximately $2.20 /kg. However, with multiple large-scale ANG storage project installations, the substantial increase in manufacturing volume and associated economies of scale is anticipated to drop the carbon price. A carbon cost of around $1.50 /kg is targeted and used in Table 13. The average packing density for this carbon is about 500 kg/m^3.
- The high-performance carbons are not currently manufactured in large quantities and therefore are not economically feasible at this time. With further research and development, they could potentially be viable in 5 to 15 years. The cost to manufacture a small volume of the AGLARG carbon is approximately $100 per kg, but similar to commercial grade carbon, this is expected to drop with an increase in supply. Advantica Inc. projects that a cost of $4 per kg may be achievable for this quantity of similarly performing carbon in a 5 to 15 year time horizon. This carbon is in a monolithic form, and has a typical density of 550 kg/m^3.
- *Process and control equipment* - This includes a gas heater to ensure consistent gas quality on delivery, valves and piping.
- *Compressors* - When a low-pressure discharge point (20 psig or lower) is available, no inlet or outlet compression is anticipated for an ANG storage system. This provides significant cost savings over CNG by eliminating the need for compression and the subsequent gas cooling. In the operating scenarios identified for California applications, however, outlet compression is required to increase the ANG gas pressure to meet the respective pipeline pressure, resulting in a large and costly discharge compression duty.

Based on these system components, capital expenses are estimated for operating scenarios 1&2. Table 13 assumes the use of a commercial-grade carbon while a high-performance carbon has been included in Table 14. Projected costs and performances are expected to be achievable within 5 to15 years based on current performance.

Table 13 CAPEX Estimation for ANG Storage System (Commercial-grade Carbon)

	Operating Scenario 1		Operating Scenario 2	
ANG Vessels (#)	18	$39,847,500	44	$97,405,000
Carbon (tons)	7260	$14,580,000	17,740	$35,640,000
P&C Equipment	LS	$12,688,100	LS	$18,531,300
Compressors	LS	$16,250,000	LS	$42,550,000
TOTAL		**$83,365,600**		**$194,126,300**
Storage Capacity	56 MMcf		140 MMcf	
Unit Storage Cost	$1.50 per scf		$1.40 per scf	

Table 14 CAPEX Estimation for ANG Storage System (High-performance Carbon)

	Operating Scenario 1		Operating Scenario 2	
ANG Vessels (#)	13	$28,778,800	31	$68,626,300
Carbon (tons)	5765	$30,888,000	13,750	$73,656,000
P&C Equipment	LS	$11,484,400	LS	$17,327,600
Compressors	LS	$16,250,000	LS	$42,550,000
TOTAL		**$87,401,200**		**$202,159,900**
Storage Capacity	56 MMcf		140 MMcf	
Unit Storage Cost	$1.56 per scf		$1.45 per scf	

For the same storage requirement, an ANG storage system using a high-performance carbon shows a higher unit storage cost, mainly due to the more expensive carbon used. The unit storage cost illustrated in the tables should only be used for comparison between the ANG systems shown. It should be noted that an important cost element, land acquisition, is not included in either scenario, and can significantly change the economics and potentially dictate the final carbon choice. ANG vessel costs in Table 13 and Table 14 are estimated based on high-pressure vessels as specific earlier in this section.

OPEX Estimation

ANG storage appears to be an attractive solution when a low-pressure discharge point is available (no additional compression is needed), benefiting from relatively low operational expenses. Typical OPEX elements for an ANG storage system are:

- General parts and maintenance, including labor
- Oil/electricity for discharge heating
- In this particular case, electricity for the compressors

Table 15 OPEX Estimation for ANG Storage System

	Operating Scenario 1	Operating Scenario 2
Parts and maintenance	$4,368,500	$10,106,500
Utilities [c]	$881,000	$2,353,000
TOTAL	**$5,249,500**	**$12,459,500**
Gas delivered per annum [c]	511 MMcf	1278 MMcf
OPEX per unit storage	$10,272 /MMcf	$9750 /MMcf

[c] Assume it operates 5% of the time

Additional Operational Considerations

Guard beds are installed to protect carbon in the main storage vessel from contamination and the carbon is expected to perform throughout the plant life. In the event of circumstances that cause the performance to degrade due to breakthrough of components from the guard beds, the carbon can be either regenerated or re-activated by heat.

An internal inspection would be required for the high-pressure cylinders approximately every 20 years of service. The carbon change out and re-activation can be scheduled with the internal vessel inspection to ensure consistent performance. A rough estimate by a specialist contractor indicates a potential expense of $45,000 per vessel for carbon unloading and re-loading, as an additional OPEX to facility operation. Table 16 illustrates estimated annual operating expenses for the operating scenarios specific to California.

Table 16 Estimated Annual Carbon Unloading and Re-loading Costs [d]

	Operating Scenario 1	Operating Scenario 2
Commercial-grade Carbon	$40,500	$99,000
High-performance Carbon	$29,250	$69,750

[d] These are average yearly costs, assuming a vessel internal inspection every 20 years

Capital and operating expenditures estimated above illustrate the high costs associated with scaling ANG technology to the operating scenarios identified in California. These costs, and potential costs associated with significant land acquisition required for storage vessels, make implementation of this technology prohibitive at the present time. Advancements in performance of activated carbon materials can potentially alter this conclusion, and it is recommended that further research be conducted prior to consideration for these operating parameters.

Technology Status

The development of ANG technology has been primarily executed at laboratory scale and has not yet been expanded for commercial application. Several organizations, such as Energtek, All-Craft (led by the Missouri-Columbia University), and Honda have been developing the ANG technology but are focusing primarily on activated carbon development and small-scale vehicular applications. Advantica is currently working with the BG Group to put the first pilot ANG diurnal storage plant on natural gas distribution network.

The maturities of the key ANG technology elements include:

Adsorbent Materials

Recent high surface area and nano material development for hydrogen storage has revived the interest in the materials for absorbed natural gas (ANG) storage. A key technical hurdle for ANG storage systems is to achieve higher capacity adsorbents for natural gas. Studies carried out to date show that, in general, high surface area activated carbons are better adsorbents for natural gas than zeolite type materials and other adsorbents. In 1998, at ambient temperature and 500 psi, the high surface area carbons could achieve about 230 V/V, The surface area of the carbons ranged from 800 to 1000 m2/g, which is much lower than that of currently developed high surface area carbon, which are up to 5000 m2/g. Meanwhile, the pore size of the carbon is critical for methane storage. To achieve higher capacity adsorbents, the micropore volume must be maximized and the mesopore and macropore volume must be minimized. Another factor that affects the methane storage is the high surface area carbon density, which represents the methane storage volumetric capacity and gravimetric capacity. If the high surface area carbon density is too low (fluffy), the methane storage volumetric capacity will be very low. Therefore, carbon materials for methane storage must have a high surface area, micro pore size and uniform pore size distribution, and high material density.

Currently, the highest performance activated carbon is the one developed by the Atlanta Gas Adsorbent Research Group (AGLARG), which included Advantica as the lead technical partner. The Missouri-Columbia University is working on a corncob-derived activated carbon. A high capacity has been claimed but on a very small lab scale. The carbon is not available commercially and therefore the results cannot be verified.

BASF is also investigating the use of metal-organic frameworks (MOF) to be used for adsorption.

Energtek has claimed vehicle ranges which translate into 155 v/v delivery performance at 850 psig for a processed activated carbon.

Process Control

As mentioned earlier, odorants and higher hydrocarbons will be preferentially retained on the carbon and have adverse impacts on the long-term storage performance of the material. Advantica led a $6 million absorbed natural gas system with guard bed device (ANGUARD) project supported by the European Commission to develop an integrated ANG system with guard bed to ensure long-term performance. This system incorporates a control system and heating of gas on discharge to ensure consistent gas quality is delivered into the pipeline.

Considering all of the above, the carbon technology is currently at a state ready to be demonstrated at a commercial scale in order to identify any further developmental gaps.

The technology for vehicle on-board storage applications have been proven in the following projects:

- (1990's) AGLARG project where vehicles including a pick-up truck and later a Honda Civic were converted to run on ANG. The system was found to be performing consistently even after 25,000 miles of road testing.

- (2007) An ANG scooter was converted by Advantica in collaboration with BG using activated carbon to target the Indian 2-wheeler market. The scooter was field tested and the demonstration was successfully concluded.
- (2007) An ANG scooter was converted by Energtek using activated carbon.
- (2007) BASF converted a transit using MOF which completed a round-the-world trip.

In terms of the large-scale storage applications, though still significantly smaller than the California based operating scenarios analyzed within this report, the following work is being conducted:

- Development of ANG technology alongside Transco (which is now National Grid) as a replacement for the low-pressure gas holders and improvement of storage capacity at the high-pressure storage sites.
- Investigating the use of ANG technology to capture boil-off gas at LNG sites.
- Completing a simulation study for one of BG's overseas assets and currently working on implementation of a pilot ANG demonstration on a distribution pipeline network.

No work is currently being conducted to address the scale of operating scenarios identified in this report (Scenarios 1, 2 or 3).

Technology Developmental Needs

Carbon/Adsorbent Material

There are currently no commercial installations of large-scale ANG technology in operational gas distribution or transmission networks. There are a number of areas where improvements to the technology could be made to improve this viability further, and most of these should be realized within a 5 to 15 year time period.

Currently, a range of carbon adsorbents are used in laboratory demonstration ANG systems. The type of material used depends largely on the application, with higher cost engineered materials used for small scale vehicle applications, and simpler low cost materials derived from generic activated carbons being specified for large scale demonstrations.

Ongoing work using new materials for adsorbent production, both activated carbon and organo-metallic chemistry based material is leading to improvements in adsorption performance. An example of the former is the corn-cob based carbon developed by the University of Missouri, which claims an uptake of 180v/v. The latter could be represented by the BASF Basostor^{tm} metal organic framework (MOF) material, which was recently tested in a car driven across South East Asia. It is likely that these materials could be produced in commercial quantities in the next decade, although their costs are uncertain.

The Gas Technology Institute is also working with its partners to develop high surface area carbons for hydrogen storage and possibly for methane storage. Two kinds of carbons have been developed. The first – a high surface carbon - has a surface area of 1176 m2/cc and a density of 1.12 g/cc (surface area of 1,040 m2/g). The pore size is 0.5~0.8 nm wide with a micro pore volume of about 0.4 cc/g. The other special carbon is the Brunauer-Emmett-Teller (BET) (nitrogen), with a surface area of 3,266 m2/g.

- Barret-Joyner-Halenda (BJH) desorption cumulative pore volume of pores between 1,200 Angstroms and 6.5 Angstroms diameter is 1.893 cc/g.
- BJH desorption cumulative surface area of pores between 1,200 Angstroms and 6.5 Angstroms diameter is 4,762 m2/g.
- BJH desorption average pore diameter (4V/A) is 15.9 Angstroms.

This high surface area carbon has demonstrated 6.7 wt% hydrogen storage at 77K and 0.6 wt% at room temperature. This carbon could be a good candidate for methane storage. Further investigation is required.

It is also possible to improve the performance of existing activated materials by a mixture of chemical processing and densification, although this process can increase the material cost significantly.

Further research and development is required to reach the levels of theoretical storage performance indicated in this report, and ANG technology has yet to move significantly towards this goal while retaining low cost and the ability to manufacture at large scale.

Process Controls/Heat Transfer

ANG discussions and claims often concentrate on simple storage capacity, rather than the more important working capacity. This depends primarily on the ability of a system to achieve efficient deliverability at required discharge pressures. Unfortunately, an adsorbent material with a high capacity will also exert a high affinity for adsorbates, retaining a large fraction of this gas even at the lowest discharge pressures. This volume can be up to 20% of the stored gas, and can be highly gas-component dependant, with non-methane fractions being the most strongly held. Adsorbent development needs to concentrate on reducing this retained volume, while at the same time reducing the separation effect which can cause stored gas quality to change over a number of cycles.

Current ANG technology uses pre-adsorber "guard beds" to remove higher hydrocarbons (C5 and above) to protect the main bed from degradation. These have a stronger affinity to larger molecules, and are regenerated by a mixture of temperature and pressure variations under control of a temperature sweep to maintain pipeline gas quality. Reducing the temperature variation requirement would improve the technical and economic performance of ANG systems.

Adsorption is an exothermic process, and activated carbon is a highly effective thermal insulator. This means that the adsorption process leads to trapped heat in the storage vessel, lowering adsorption capacity. Unless this heat can be removed, ANG will not efficiently achieve higher capacities of storage under ambient isothermal conditions. Conversely, desorption is an endothermic process and heat required needs to be taken from the storage bed, thus reducing temperature and potentially limiting deliverability under some high-demand conditions.

There are numerous methods to address this, none of which have been fully implemented as yet, and further research is required to improve heat removal from ANG systems. Methods include heat removal through heat pipes and heat exchange fluids, internal conducting fins, thermally conductive additives, and phase change materials which store latent heat of fusion. Each of these has the disadvantage of reducing the available space for gas storage (while increasing costs). Use of phase change materials could prove particularly effective if the material could potentially be incorporated more closely in the void structure of the adsorbent, thereby having little or no impact on the density of adsorbent in the vessel.

Tank Inspection Regime

Current standards for high-pressure vessels require a vessel internal inspection after every 25% of the design fatigue life or 20 years of service, whichever is shorter. Though carbon material in an ANG system is expected to maintain its effective performance for a longer period than this, unloading and re-loading of carbon to get ready for internal inspection relate to unnecessary additional costs and expose carbon to potential contamination.

An exemption for a replacement would be advantageous, if an external non-destructive inspection can be demonstrated as sufficient for this application.

Conclusions

The two operating scenarios being investigated for the state of California are very large for ANG applications, closer to those expected for LNG operation or other similar technologies. Inlet and outlet compression is required in the analyzed ANG system to maximize the working capacity, hence reducing the number of vessels required. The third operating scenario, based on a portable system, was not included in this analysis due to the technology being on the market.

The estimated CAPEX and OPEX for the two operating scenarios are summarized below:

Table 17 CAPEX and OPEX Summary

	Commercial-grade Carbon		High-performance Carbon	
	Operating Scenario 1	Operating Scenario 2	Operating Scenario 1	Operating Scenario 2
Storage capacity	56 MMcf	140 MMcf	56 MMcf	140 MMcf
No. of vessels	18	44	13	31
CAPEX	$83.4 million	$194.2 million	$87.4 million	$202.2 million
OPEX per year	$5.29 million	$12.56 million	$5.28 million	$12.53 million

- Aspects of ANG technology are close to commercialization with a pilot diurnal storage demonstration plant being planned on a real network.
- The technology gaps identified for commercialization in the next 15 years include:
    - Carbon and adsorbent improvement to achieve higher storage capacities
    - Heat transfer management to improve the storage efficiency
    - Vessel inspection regime to minimise disruption to the operation
- ANG mobile storage as backup supply during network disruption, similar to operating scenario 3 defined in this report, is recommended to demonstrate the full capabilities of an ANG system on a small scale. With the high-pressure inlet gas and low-pressure distribution discharge points available, ANG has advantages over storage solutions such as LNG and CNG for its modular construction, process simplicity, low CAPEX and OPEX (no compression is needed), as well as good safety performance. It is not currently recommended for implementation due to economic considerations.

Small Scale LNG Technology

Technology Description

Liquefied Natural Gas (LNG) storage has long been used by U. S. gas utilities to help meet peak natural gas demand. These are typically large LNG facilities that are employed when peak demand exceeds available supply (from an engineering or cost perspective) of natural gas. The siting of new large LNG storage facilities and the source of supply of LNG (transported to the site or on-site production) are important considerations in considering LNG peak shaving. The LNG is stored in vacuum jacketed pressure vessels to minimize heat gain. Excess pressure due to heat gain needs to be released, typically back into the natural gas pipeline. Prior to introduction into the natural gas pipeline, the gas needs to be heated and odorized.

Operational Feasibility

Natural gas can be converted from a gas to a liquid form (i.e., liquefy) at temperatures ranging from –220°F to –260°F (depending on gas composition and pressure). The sensible and latent energy required to transform methane from, for example, a gas at 60°F to a saturated liquid at -231°F (both at 30 psig) is approximately:

Table 18 Conversion Energy Requirements

Sensible Heat (Btu/lb)	155.25
Heat of Condensation (Btu/lb)	204.75
Total Change (Btu/lb)	360.00

Prior to liquefaction, the natural gas (either pipeline or other source) needs to be cleaned. Several cleanup steps typically are employed, depending on the gas composition;

- Inlet filter separator to remove any free liquid or solids
- Carbon dioxide (CO_2) and hydrogen sulfide (H_2S) removal
- Water (H_2O) removal
- Sulfur removal
- Mercury removal

Several liquefaction technologies have been developed, many commercially, as described in Table 19.

Table 19 Summary of Candidate Liquefaction Cycles for LNG Plants

LIQUEFIER TYPE	OPERATING PRINCIPLE	REMARKS AND TRADEOFFS
Precooled Joule-Thomson (JT) Cycle	A closed-cycle refrigerator (e.g. using Freon or propane) pre-cools compressed natural gas, which is then partially liquefied during expansion through a JT valve	Relatively simple and robust cycle, but efficiency is not high. Used in Anker Gram Inc. onsite liquefier for LNG truck fueling (which is no longer operating).
Nitrogen Refrigeration Cycle (also called closed	Nitrogen is the working fluid in a closed-cycle refrigerator with a compressor, turboexpander, and heat exchanger. Natural gas is cooled and	Simple and robust cycle with relatively low efficiency. Using multiple refrigeration stages can increase efficiency. Used in CryoFuel Systems Hartland LFG liquefier

Brayton/Claude cycle)	liquefied in the heat exchanger.	demonstration.
Cascade Cycle	A number of closed-cycle refrigerators (e.g. using propane, ethylene, methane) operating in series sequentially cool and liquefy natural gas. More complex cascades use more stages to minimize heat transfer irreversibility.	High-efficiency cycle, especially with many cascade steps. Relatively expensive liquefier due to need for multiple compressors and heat exchangers. Cascade cycles of various designs are used in many large-capacity peakshaving and LNG export plants.
Mixed-Refrigerant Cycle (MRC)	Closed cycle refrigerator with multiple stages of expansion valves, phase separators, and heat exchanger. One working fluid, which is a mixture of refrigerants, provides a variable boiling temperature. Cools and liquefies natural gas with minimum heat transfer irreversibilities, similar to cascade cycle.	High-efficiency cycle that can provide lower cost than conventional cascade because only one compressor is needed. Many variations on MRC are used for medium and large liquefaction plants. ALT-El Paso Topock LNG plant uses MRC. GTI is developing simplified MRC for small plants (under 10,000 gpd).
Open Cycles with Turboexpander, Claude Cycle	Classic open Claude cycle employs near-isentropic turboexpander to cool compressed natural gas stream, followed by near-isenthalpic expansion through JT valve to partially liquefy gas stream.	Open cycle uses no refrigerants other than natural gas. Many variations, including Haylandt cycle used for air liquefaction. Efficiency increases for more complex cycle variations.
Turboexpander at Gas Pressure Drop	Special application of turboexpander at locations (e.g. pipeline city gate), where high-pressure natural gas is received and low-pressure gas is sent out (e.g., to distribution lines). By expanding the gas through a turboexpander, a fraction can be liquefied with little or no compression power investment.	This design has been applied for peakshaving liquefiers, and it is currently being developed by Idaho National Engineering and Environmental Laboratory (INEEL) in cooperation with PG&E and SoCalGas to produce LNG transportation fuel. Very high or “infinite” efficiency, but special circumstances must exist to employ this design.
Stirling Cycle (Phillips Refrigerator)	Cold gas (usually helium closed cycle using regenerative heat exchangers and gas displacer to provide refrigeration to cryogenic temperatures. Can be used in conjunction with heat exchanger to liquefy methane.	Very small-capacity Stirling refrigerators are catalog items manufactured by Phillips. These units have been considered for small-scale LNG transportation fuel production.
TADOPTR	TADOPTR = thermoacoustic driver orifice pulse tube refrigerator. Device applies heat to maintain standing wave, which drives working fluid through Stirling-like cycle. No moving parts.	Currently being developed by Praxair and LANL for liquefaction applications including LNG transportation fuel production. Progressing from small-scale to field-scale demonstration stage.
Liquid Nitrogen Open-Cycle Evaporation	Liquid nitrogen stored in dewar is boiled and superheated in heat exchanger, and warmed nitrogen is discharged to atmosphere. Counterflowing natural gas is cooled and liquefied in heat exchanger.	Extremely simple device has been used to liquefy small quantities of natural gas. More than one pound of liquid nitrogen is required to liquefy one pound of natural gas. Nitrogen is harmless to atmosphere. Economics depends on price paid for liquid nitrogen.

Adapted from USA Pro/California Energy Commission, “California LNG Transportation Fuel Supply And Demand Assessment”, January 2002, with modifications

Small Scale Liquefaction

Small scale liquefaction is technically feasible although economically challenging due to scaling issues, depending on the processes. Currently, there are two organizations promoting small-scale liquefaction technologies; Prometheus Energy using a Nitrogen Refrigeration Cycle and Linde BOC using a Mixed-Refrigerant Cycle (MRC).

Prometheus Energy is a fuel company that produces, sells and distributes LNG. They specialize in the small scale production of LNG from landfill gas, stranded gas wells, coal bed methane and agricultural operations. Prometheus Energy has developed projects in Fresno County, CA and the Frank R. Bowerman landfill in Irvine, CA. The Bowerman LNG facility has a design capacity of 5,000 gallons LNG per day. In early January 2008, the company claims to have reached design capacity production rates.8

Figure 55 Prometheus Commercial LNG from Landfill Gas Facility

Linde BOC is commercializing the technology developed by GTI. GTI developed a novel natural gas liquefier system for smaller applications with sponsorship of the U.S. Department of Energy. This program is targeted toward market applications of 30,000 gallons or less of LNG production per day. The patented system uses mixed refrigerants in a simple refrigerant loop. The system is packaged into a transportable skid for rapid deployment.

Standardized refrigeration compressor and heat transfer components allow for easy scalability of the system to match various LNG market needs. The use of standardized components results

[8] Prometheus Energy Press Release, "Bowerman LNG Plant Achieves Production Targets", January 3, 2008

in a comparably low first-cost position for this technology compared to scaling down conventional liquefaction systems.

Extensive cycle modeling has resulted in a mixed refrigerant system that maximizes system performance and efficiency. A pre-commercial prototype system producing over 1,000 gal/day has been operated for extended periods to validate performance and reliability. The pre-commercial prototype uses a gas engine drive to reduce operating costs and integrate with the gas processing system to capture natural gas vapors. Electric drive options are also possible. Linde BOC is targeting the system for remote gas recovery, bio-gas recovery and other specialty natural gas markets. The systems range in size from 5,000 to 30,000 gallons LNG per day.

Operating Scenarios 1 and 2

Only operating scenarios 1 and 2 are evaluated in this report for small scale LNG storage. Given the process facilities required for LNG re-gasification, the portability required in operating scenario 3 is not achievable at this time and is therefore not evaluated for LNG applications.

Generally, there are no significant technical hurdles to employing LNG for large (utility) or medium (specific industrial / power plant) gas peak shaving, depending on the size of the application. Recent work in small-scale (10,000 to 30,000 gallons LNG per day) liquefaction enables this technology to be employed in a more dispersed manner, within the gas utility infrastructure.

Typical LNG peak shaving systems are designed to accommodate a "once in a decade" event. They typically are sized with storage capacity of 1.0 BCF (1,000 MMcf) and higher (greater than 12 million gallons of LNG). This tank size will accommodate 14 -16 days at the desired daily output. For example, the 1.0 BCF storage capacity facility would typically deliver 60 MMcf per day of natural gas. Since the deployment is infrequent, the liquefaction capacity is typically sized to refill the storage in 200 days (1,000 MMcf / 200 days = 5 MMcf per day). These are large facilities with on-site construction of liquefaction, storage and vaporization equipment.

Table 20 Typical LNG Peak Shaving Specifications

Daily Delivery (MMcf/day)	Days	Storage (MMcf)	Storage (LNG Gallons)	Liquefaction Period (days)	Liquefaction Capacity (MMcf / day)	Liquefaction Capacity (gallon / day)
60	16	> 1,000	> 12,226,000	200	5	61,000

The small scale liquefiers (10,000 to 30,000 LNG gallons per day or 0.82 to 2.45 MMcf natural gas per day) are being employed to generate LNG primarily for vehicular use in LNG fueled trucks and buses. California currently imports most of the LNG for vehicles from neighboring states. The shipping costs have made local liquefaction appealing. The LNG storage for these facilities is typically sized for about two days of production in factory constructed LNG tanks up to 85,000 LNG gallon (6.95 MMcf natural gas) capacity.

Table 21 Small Scale LNG Operating Specifications

Daily Liquefaction Capacity (MMcf / day)	Daily Liquefaction Capacity (LNG Gallons)	Storage Capacity (MMcf Natural Gas)	Storage Capacity (LNG Gallons)
0.82	10,000	$\leq$ 6.95	$\leq$ 85,000
2.45	30,000	$\leq$ 6.95	$\leq$ 85,000

Table 22 includes the performance requirements for the Operating Scenarios 1 and 2 identified for analysis; 1) Electric Generation, 2) Pipeline Capacity.

Table 22 Operating Scenario 1&2 Parameter

Scenario	Hourly Delivery (mmcf/hr)	Hr per Day	Daily Delivery (mmcf/day)	Days	Delivered/ Storage (mmcf)	Storage LNG Gallons)
1	2	14	28	2	56	685,000
2	5	14	70	2	140	1,711,640

For both scenarios, it is desired that the liquefaction system be sized to refill storage in 30 days. The liquefaction capacities are;

Table 23 Liquefaction Rate Parameters

Scenario	Required LNG	Days	Liquefaction Rate (Mmcf/day)	Liquefaction Rate (LNG Gallons)
1	56	30	1.87	22,800
2	140	30	4.67	57,000

For comparison, the Large Peak Shaving and Small Scale Liquefaction are shown in Table 24 below with the two scenarios of interest.

Table 24 LNG Comparison Summary

Scenario	Liquefaction Rate		Cycle Period	Storage Capacity		Delivery	
	(Mmcf/day)	(LNG Gallons)	Days	(mmcf)	(LNG Gallons)	(mmcf/day)	Days
Large Peak Shaving	5	61,000	200	$\geq$ 1,000	$\geq$ 12,226,000	60	14 - 16
Small Scale Liquefaction	0.82 - 2.45	10,000 - 30,000		$\leq$ 6.95	$\leq$ 85,000	n/a	
Scenario 1	1.87	22,800	30	56	685,000	28	2
Scenario 2	4.67	57,000	30	140	1,711,640	70	2

The two scenarios are sized between the large peak shaving and small scale liquefaction applications. The liquefaction technology could utilize either based on the scenario, scenario 1 is similar to small scale liquefaction and scenario 2 is similar to a large peak shaving application. The LNG storage is an issue; there are two orders of magnitude in storage capacity difference between the large peak shavers and small scale liquefaction. The two scenarios fall in between. The availability and cost of these LNG storage tanks are a significant issue, and with no economies of scale, will be custom designs.

Process flow diagrams for Scenario 1 and Scenario 2 are shown in Figure 56 and

Figure 57 on the following pages, courtesy of Northstar Industries (Quine, 2008).

Figure 56 Operating Scenario 1 Process Flow Diagram

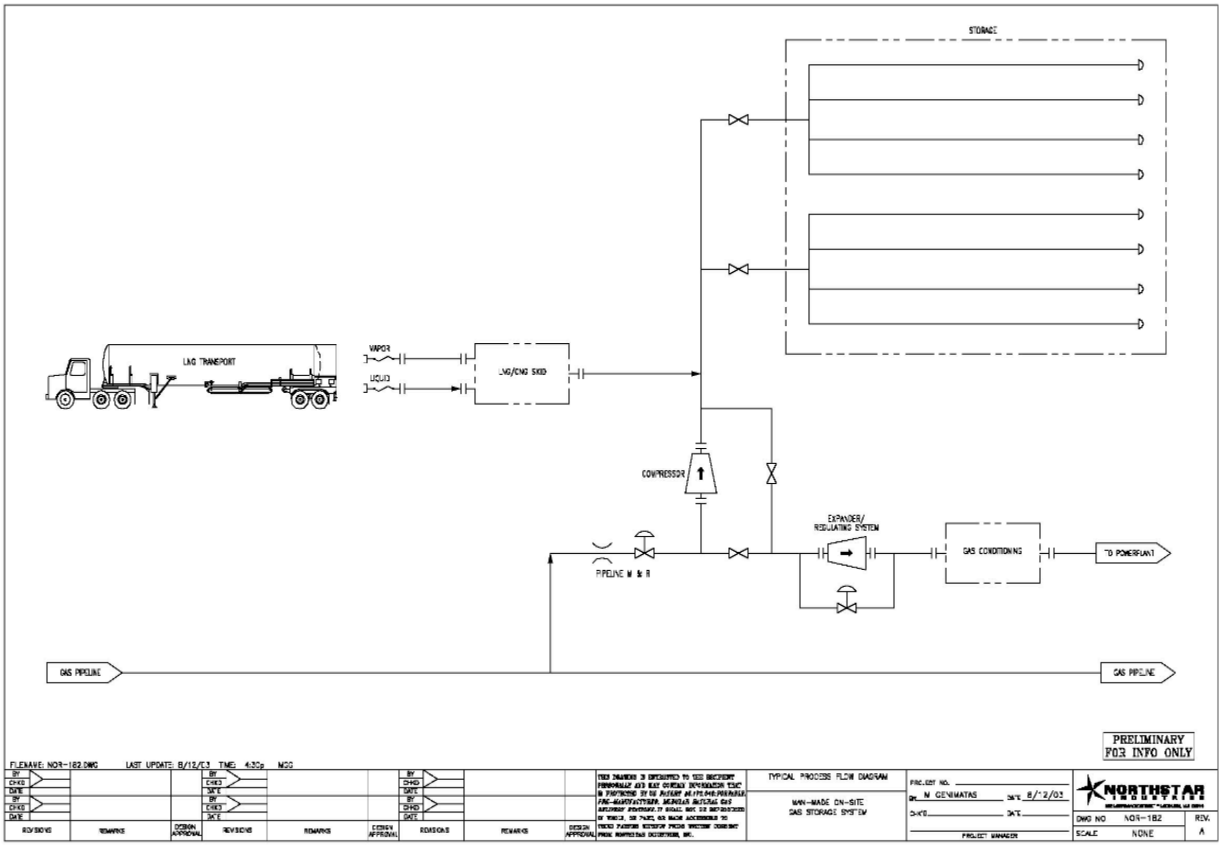
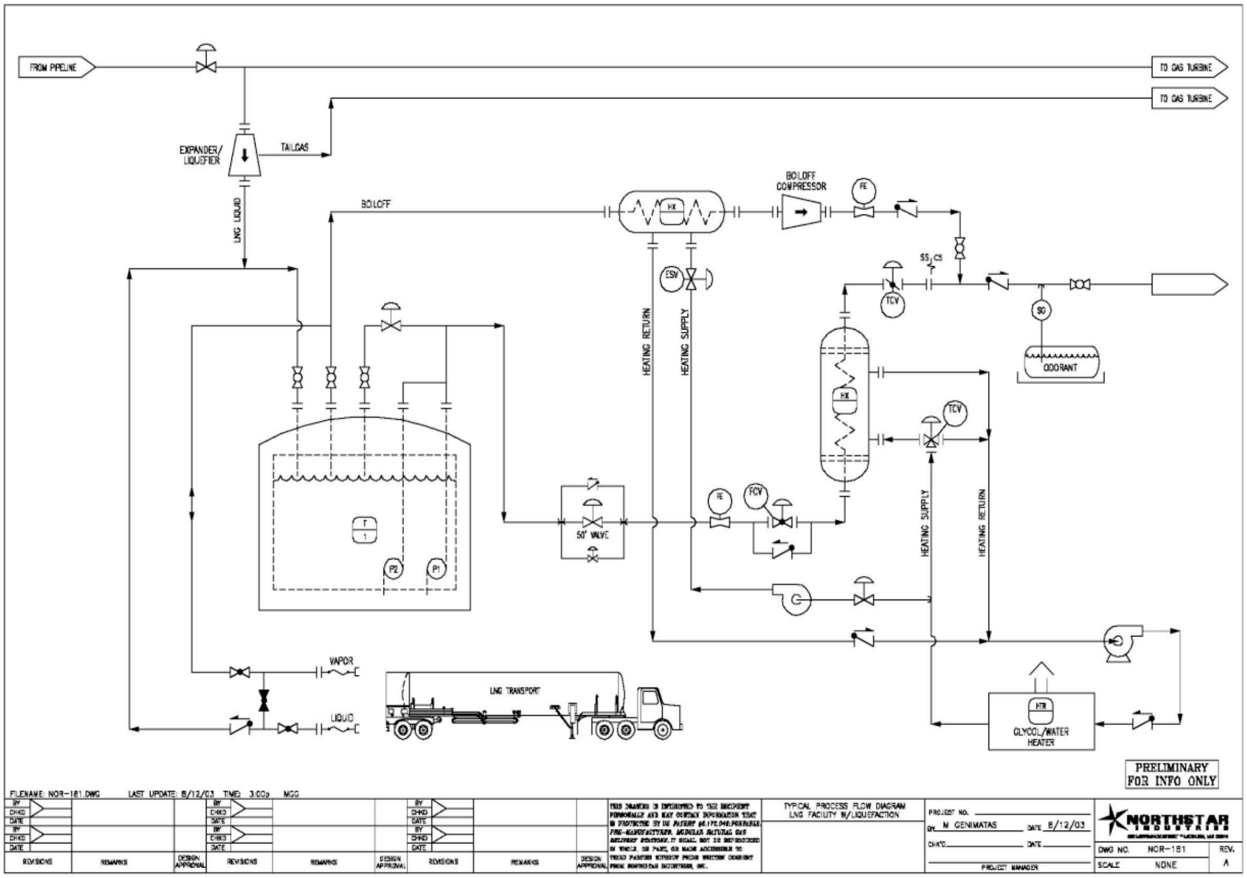


Figure 57 Operating Scenario 2 Process Flow Diagram



Economic Feasibility

As previously indicated, LNG technology and facilities have been implemented in considerable numbers throughout the world. There are few operational facilities, however, that capture the specifications and parameters defined in the operating scenarios for this research. Therefore, rough estimates were provided by LNG manufacturing and consulting companies for this report. As a point of reference, the following table provides comparative project costs for two operating LNG facilities, in 2003 dollars;

Table 25 Comparative LNG Project Costs

	Peak shaver		Vehicle fuel	
	15 million scfd liquefaction		15 million scfd liquefaction	
	100,000 m3 storage (26,420,000 gallons)		7,000 m3 storage (1,850,000 gallons)	
	200 million scfd sendout		30 million scfd sendout	
	200 day/yr operation		350 day/yr operation	
Drives	**Motor**	**Turbine**	**Motor**	**Turbine**
Power, ¢/kWh	3	5	3	5
Fuel, $/million Btu	3	2	3	2
Capital, $ million	39	43	23	27
Operating cost, $/thousand scf	0.47	0.39	0.47	0.39
Capital, $/thousand scf	1.56	1.72	0.51	0.60
LNG to tank, $/thousand scf	2.03	2.11	0.98	0.99

(B.C. Price, Black & Veatch Pritchard Inc., Overland Park, Kansas, 2003)

Although formal project quotes were beyond the scope of this effort, the current cost estimates for Operating Scenario 1 and Operating Scenario 2 were provided from two sources, Northstar Industries and an informed industry consultant, and are shown below;

Table 26 Small Scale LNG Capital Cost Estimate

Project Cost ($)	Operating Scenario 1	Operating Scenario 2
Source 1	$30 million	$55 million
Source 2	$40 million	$64 million

These estimates provide an order of magnitude for the small scale LNG facility option. Based on these estimates, the cost of delivering a Mcf of gas to the distribution or transmission system would be approximately $2 more than pre-liquified gas.

Technology Status

As noted in the previous section, the scenarios considered for this study are unique compared to common LNG peak shaving facilities and their operation. Although the liquefaction and vaporization rates are not uncommon, the relatively short (30 day) cycle time requires LNG tank sizes that are between the largest factory-built units and the larger tanks typically used in LNG peak shaving facilities. These have cost implication, but are not technological barriers.

Figure 58 below is an example of a LNG peak shaving facility.

Figure 58 Northstar Industries City Gate LNG Plant

A typical LNG peak shaving plant has characteristics as shown in Table 27

Table 27 Typical LNG Peak Shaving Plant Parameters

Plant characteristics	Peak shaving
Liquefaction, million scfd	5-25
Operating period, days/yr	150-200
Storage, m3 (days production)	50,000-100,000 (150-200)
Sendout	Vapor
Sendout rate (relative to liquefaction rate)	10-20 times
Sendout type	Pipeline

(B.C. Price, Black & Veatch Pritchard Inc., Overland Park, Kansas, 2003)

Compressed Natural Gas

Technology Description

The system identified for a CNG “dispersed” gas storage land based application, named VOLANDS^{tm} ("Volume Optimized Land Storage"), has been conceived and developed by EnerSea LLC to provide specific storage quantities of natural gas with high cyclability and delivery rates from a site convenient to demand markets, such as pipelines (major industrial consumers or LDCs) and power generating installations. The system design is based on proprietary VOLANDS technology that integrates volume-optimized storage (i.e. storage at a commercially-balanced combination of pressure and temperature) with a chilled liquid displacement system to store and recover natural gas from a secure, inerted and insulated cold-box containing an assembly of large diameter pipe tanks. EnerSea LLC collaborated with GTI to provide detailed design economic analysis in the following sections.

VOLAND^{Stm} operates on the same principles as EnerSea's VOTRANS^{tm} ("Volume-Optimized Transport and Storage") CNG marine transport technology. More information on this commercialized system can be found in the Section 4.0 Appendix.

Figure 59 CNG Land Based Vertical Storage System Rendering (1)

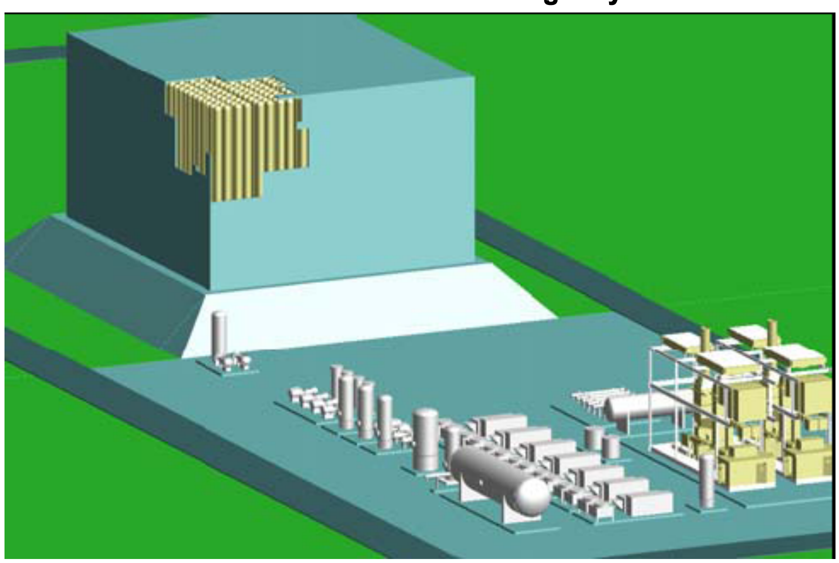


Figure 60 CNG Land Based Horizontal Storage System Rendering (2)

Operational Feasibility

System Components

The basic VOLANDS system is comprised of four main components:

- The Loading Subsystem
- The Storage Containment System (the "Z-pack")
- The Unloading Subsystem.
- Utility Systems

The system can be designed to receive, store and deliver natural gas according to a specific duty schedule, specified to the meet the client's storage volume and cyclability requirements.

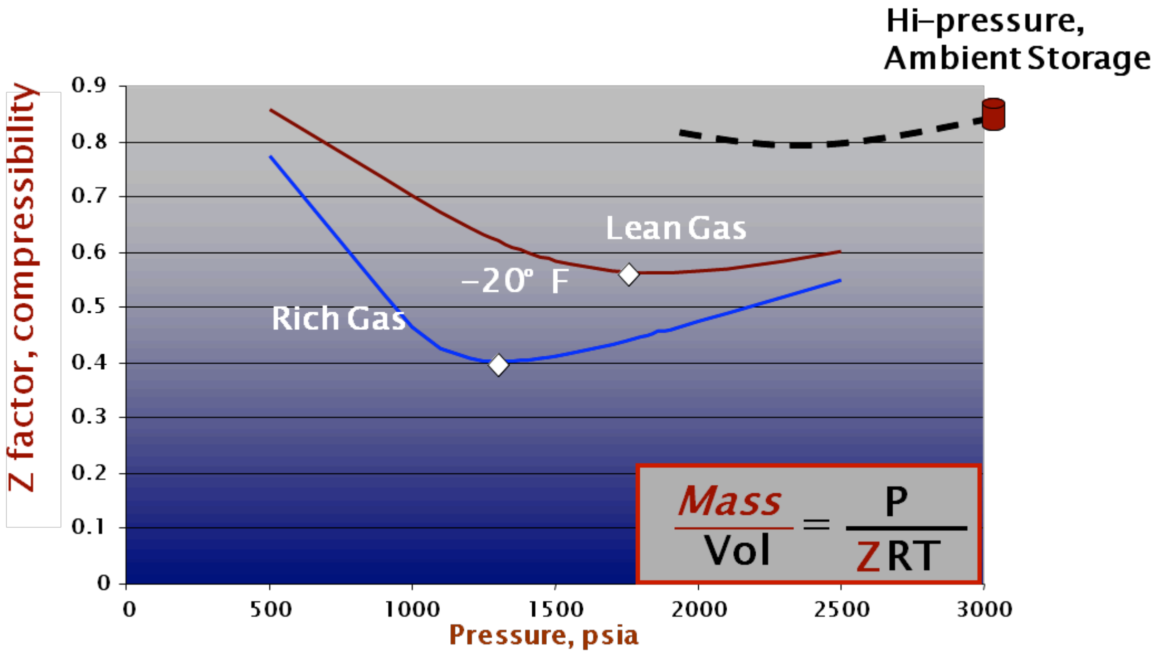
Loading Subsystem (injection):

The loading system is comprised of largely off-the-shelf designs and equipment, including:

- Inlet gas scrubber
- Gas compressors (2 x 50%)
- Coolers
- Refrigeration system, including:
- Chillers
- Refrigeration compressors (3 x 33%)
- Condensers
- Hydrate control system
- Inlet meter

The gas supply from the incoming pipeline is chilled (nominally to -10 to -20°F, depending on gas quality and overall project economic optimization) and then compressed to the desired storage pressure (typically 1750-2000 psig for a pipeline quality lean gas). The pressure-temperature optimization process is based on the behavior of natural gas compressibility at reduced temperatures, as shown in Figure 61 below:

Figure 61 CNG Pressure/Temperature Optimization



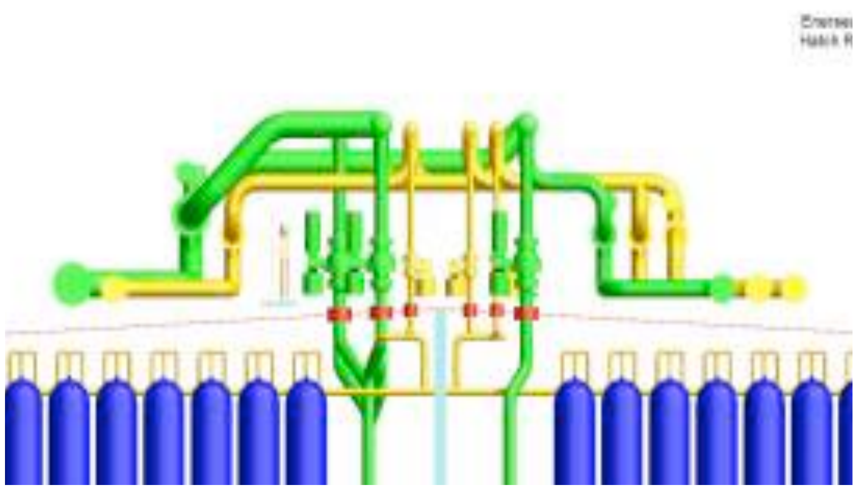
The gas is then injected into storage, driving an ethylene glycol/water mixture out of the storage pipe-tanks in a step-wise process where the liquid "cascades" into and out of successive groups of tanks (a manifolded group of pipe containers forms a "pipe tank" or "tier"). This process also mitigates the effect of heat of compression that would otherwise create a further inefficient use of storage capacity.

Storage Containment System

Figure 62 CNG Storage Cylinder

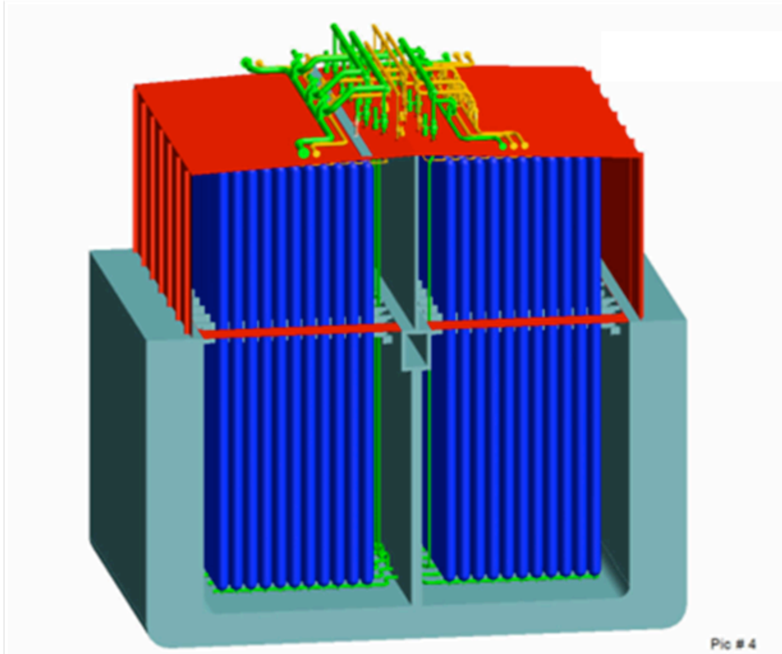
The VOLANDS gas containment system utilizes high strength carbon steel pipe with proven service and reliability service in pipeline applications. The storage volume is determined by the number of individual storage tanks at the facility. Each tank is nominally 42″ in diameter by approximately 120′ long. Tanks are manifolded to form tiers that represent optimum volumes based on customer specific needs for injection and withdrawal.

Figure 63 Gas Containment System



The overall dimensions of the VOLANDS unit will be determined based on the configuration (i.e. horizontal or vertical). The VOLANDS unit (125 MMcf storage capacity - horizontal) designed for Duke Energy was approximately 740ft long x 92ft wide x 32- 40ft high.

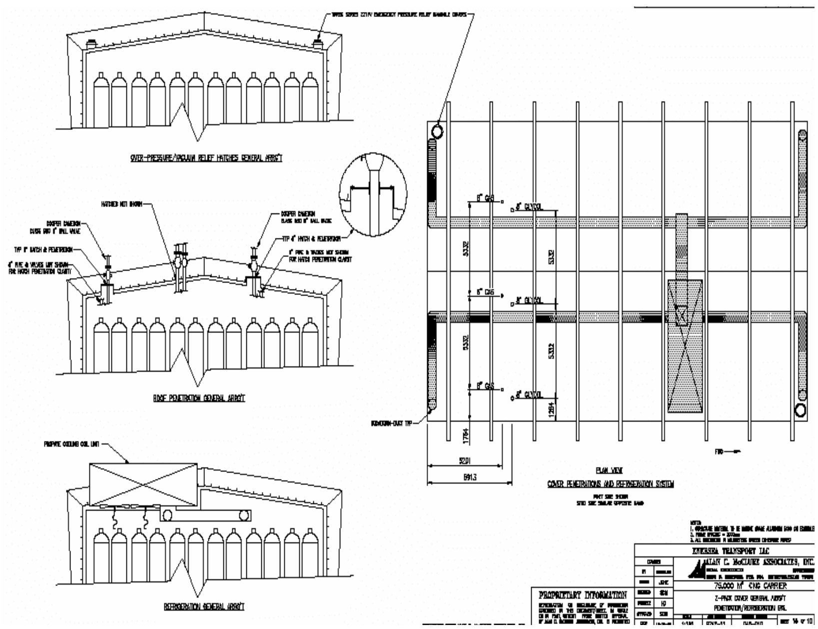
Figure 64 CNG Storage System Configuration



In the horizontal orientation, the gas storage pipes are supported on transverse footing beams spaced on 40ft centers along its length. The primary storage facility is formed as a cold box with a sealed, insulated skin that contains a chilled inert (nitrogen) atmosphere. The storage tank elements were specified as 126 premium X70 pipes with 36" diameter and 720ft long, closed with end caps. The pipes are arranged in pairs for fabrication and support purposes, but for operating purposes the pipe-tanks are manifolded together in 18 groups of 7-pipe tiers (or "manifold cluster groups"). Valves are provided to control pressures and fluid movements on a "tier-by-tier" basis. The pipe-tanks are individually supported on sturdy shaped forms of a low resistance material such that expansion and contraction of the pipes can be accommodated.

In the vertical orientation of the containment subsystem, the storage pipe tanks would consist of 42"dia by 120 foot X70 (or X80) pipe. The tanks are interconnected by manifolds at the top (for gas) and bottom (for liquid) into tiers. Manifolds are connected to upper and lower headers. The headers then lead to the primary inlet and discharge lines to/from the facility.

Figure 65 CNG Storage Process Schematic



Each tank is supported on cup-shaped pads or skirts on the bottom end. At approximately 2/3 the overall length, each tank is supported by a structural steel grillage that both locates the upper end of the tank and transfers the structural lateral loads. The tanks are contained within a concrete walled structure having the required complements of lateral braces applied.

The preferred method of construction includes excavation for the base of the system with a designed depth that results in the upper steel grillage being vertically located approximately 2-4 feet below the existing site grade. Typically this results in an excavation depth of ~80′ (when possible). Insulation is applied to the structure both below and above grade to provide storage temperature stability. The interior of the structure is filled with nitrogen and maintains a positive nitrogen atmosphere, approximately 0.5″ H20, during operation. Less than 10% of the storage volume is used to store displacement fluid.

The approximate dimensions and footprints of VOLANDS vertical storage facilities are listed in Table 28.

Table 28 Vertical Storage Facility Dimensions*

VOLANDS Size (MMscf)	Width (ft.)	Length (ft.)	Above Ground Height (ft.)	Depth Below Grade (ft.)	Area Required (acres)
Below around desian					
200	350	450	50	80	3.5
400	400	500	50	80	4.5
600	450	550	50	80	5.5
Above around desian					
200	350	450	120	10	3.5
400	400	500	120	10	4.5
600	450	550	120	10	5.5

*Courtesy of EnerSea

Soils surveys and other assessments need be undertaken as part of the facility design process. Alternative designs (e.g. complete above ground design or horizontal containment orientation), are also available if the facility cannot be installed as specified above.

Offloading Subsystem (withdrawal)

The stored gas is driven out of storage in a reversal of the injection process, where the cold displacement liquid is pumped around to drive gas out of successive tank groups. The gas ejected from storage is scrubbed, heated and expanded for delivery to the power plant.

The major equipment items for this subsystem include:

- Delivery displacement pumps (2 x 50% units)
- Gas scrubber
- Delivery gas heater
- Delivery control valve (storage pressure to required pressure)
- Delivery meter

The unloading system uses pumps to move the cold displacement liquid around from tank group to tank group at pressure. The displacement liquid is normally stored within the storage pipes at low pressure, but valves control its back-pressure against gas being injected to manage gas temperatures throughout the injection process. Injection/recovery ports are provided on the liquid handling system to inject fresh liquid and recover off-specification liquid as necessary.

High pressure pumps deliver displacement fluid (ethylene/glycol) at the bottom of tank tier(s) and push gas out of storage at the desired rate as the displacement fluid fills the storage tanks.

Utility and Process Support Systems

The facility requires a dedicated electrical distribution system and an integrated control system for the process as well as interface with customer operational requirements. All drivers are electric motors.

Technology Feasibility Testing

Significant testing has been completed by EnerSea and associated research, engineering, and materials testing organizations. A summary of this testing program is provided below.

ABS specified additional testing to be completed, specifically, confirmation of EnerSea's proprietary gas handling processes and proof of cargo cylinder structural capacity. EnerSea has completed the prototype test programs specified by ABS in their Approval in Principle issued in April 2003. EnerSea involved multiple clients and world-class organizations, including GTI, to ensure the test programs were carried out to meet both ABS and client requirements. EnerSea commenced Phase 1 (Test Program Design) of these testing programs in July 2003 and completed the System (or Functional) and Cargo Cylinders Test Programs in November 2005. ABS approved the results of EnerSea's Prototype Test Program in December 2005.

The initial phase (Phase 1) was completed in February 2004 for each test program. Phase 1 resolved the final scope, test set-up design, schedule and budget for the actual testing phase (Phase 2) by incorporating sponsors' needs as well as the latest regulatory considerations in the planning and engineering efforts.

EnerSea developed a team of companies to participate and perform the tasks required for the program. A brief description of each team member's role is included as follows:

- American Bureau of Shipping (ABS): ABS provided guidance during the planning Phase 1 to ensure that requirements for international maritime service are reflected into the test programs. ABS witnessed the tests performed in Phase 2.
- BendTec (BT): BT developed and qualified the weld procedures during Phase 1 that were used to fabricate the cargo cylinders. BT fabricated the heads and cargo cylinders used for testing in Phase 2.
- Gas Technology Institute (GTI): GTI developed the Functional Test Program, including design of Test Bed Module and definition of test program operational matrix during Phase 1. GTI then constructed the facilities required for testing and performed, recorded and reported results of the Functional tests during Phase 2.
- Nippon Steel Corporation (NSC): NSC provided the materials for the cargo cylinders, heads and weld procedure qualification. Mitsui & Co., Ltd. and Mitsui Tubular Products, Inc. (MITSUI) represent NSC in this project.
- NK Co.: NK, a Korean CNG cylinder manufacturer, formed the heads that were used for the cargo cylinder tests.
- Paragon Engineering Services (PES): PES transferred the cargo handling design to GTI and worked with GTI to design the facilities and develop the testing plan, including definition of normal/abnormal operational situations during Phase 1.
- Physical Acoustics Corporation (PAC): PAC developed the Acoustic Emissions (AE) monitoring requirements; including analytical studies and designs of baseline test specimens for the cargo cylinder testing during Phase 1. PAC then manufactured test

specimens, performed required baseline material qualification tests and provided AE equipment for the cargo cylinder testing during Phase 2.

EnerSea worked with GTI to develop a test program to validate the performance and operational characteristics of the system, evaluate static and dynamic aspects of the system, investigate fluid mechanical phenomenon, and to support the development of a framework for control logic and algorithms that can be applied to full-scale versions of the system. A scaled design of the VOTRANS system or Test Bed Module (TBM) was constructed for testing.

The TBM is a simple, modular multi-vessel system. These vessels were operated together (e.g. to investigate parallel filling of cylinders) and as separate banks (e.g. to examine the effects of switching banks and dynamically moving gas and fluid from adjacent vessels).

Additional information on functional testing of this technology can be found in the Section 4.0 Appendix.

Economic Feasibility

The VOLANDS concept is flexible regarding the frequency of withdrawal / injection cycles. The system can switch quickly between modes to allow seasonal, weakly or daily cycling.

EnerSea provided GTI an analysis of two operating scenarios as defined in previous sections. Below are the general assumptions used in the analysis. The operating scenario focusing on portable systems was not included in the evaluation of CNG technology due to its mature status and market availability.

Table 29 Operating Scenario 1&2 Assumptions

Parameter	Units	Value	Comments
Gas supply pressure	psig	300	During off-peak period
Gas supply temperature	deg F	75	
Gas specific gravity, avg.	air=1.0	0.6	
Gas heating value	btu/scf	1012	
Mean peak air temperature	deg F	90	
Avg. ground temperature	deg F	75	
Downstream min. delivery pressure	psig	600	
Downstream allowable temperature	deg F	50	
Storage system pressure	psig	1850	
Storage system temperature	deg F	-22	

The natural gas injection / withdrawal strategy was developed to meet the expected demand in the most cost effective manner. In operating scenario 1 (OS 1), natural gas was injected into the system on weekends (24 hrs per day) and weekday evenings (5 hrs per day).

Table 30 OS1 Operating Parameters

	Storage	Weekend	Weekday

	Size	Weekend		Weekday			
		Inj Rate/ day	Inj Rate/ hour	Inj Rate/ day	Inj Rate/ hour	Withdrawal Rate/day	Withdrawal Rate/hour
	MMcf	MMcfd	MMcf/h	MMcfd	MMcf/h	MMcfd	MMcf/h
Parameter	210	96.00	4.00	72.00	3.00		
						72.00	3.00
OPERATIONS	Sat	Sun	Mon	Tues	Wed	Thurs	Fri
Injection Hours	23	24	5	5	5	5	5
Withdrawal Hours	0	0	17	17	17	17	17
VOLUMES	Sat	Sun	Mon	Tues	Wed	Thurs	Fri
Injection Volume, MMcf	92.0	96.0	15.0	15.0	15.0	15.0	15.0
Withdrawal Volume, MMcf	0.0	0.0	51.0	51.0	51.0	51.0	51.0
STORAGE INVENTORY	Sat	Sun	Mon	Tues	Wed	Thurs	Fri
Gas Volume, MMcf	92.0	188.0	152.0	116.0	80.0	44.0	8.0

For operating scenario 2 (OS2), 250 MMcf of storage was modeled with a withdrawal rate of 96 MMcf per day.

Table 31 OS 2 Operating Parameters

	Storage Size	Inj Rate / day	Inj Rate / hour	Withdrawal Rate / day	Withdrawal Rate / hour
	MMcf	MMcfd	MMcf/h	MMcfd	MMcf/h
Parameter	250	12.00	0.50		
				96.00	4.00

The resulting capital and operating costs were developed based on operating scenarios 1&2.

Table 32 CAPEX and OPEX Cost Estimates

Parameter	Units	OS 1	OS 2
CAPEX	MMUSD	265	240
Annual Opex	MMUSD	3	3
Injection Power	MW	9	1.5
Withdrawal Power	MW	3	3
Static Power	MW	0.5	0.6

As a basis for these estimates, EnerSea would provide;

- VOLAND gas storage facility, inclusive the following major items:
  - VOLANDS containment structure, including storage cylinders for the specified storage volume and insulated structure
  - Gas handling facilities for injection and discharge operations, and container cooling system from environmental heat loads
  - Piping, valves, instrumentation for isolation, switching and shut-down valves
  - Ethylene glycol storage tank and initial ethylene glycol volume
  - Automation and controls and interface with power plant control room
  - Safety and emergency systems
- Transportation of materials to site
- Project management and engineering
- Compression system
- Operating services and management during startup and operational phases
- It is assumed that the client site would be responsible for;
  - Daily tariff, annual opex and 5-yr. purchase obligation
  - Utilities, including:
    - Power and associated switchyard and transformers,
    - Service and control air, and
    - Water
  - Installation of automation and control interface in designated plant control room
  - Location site, including right-of-ways
  - Tie-in to existing gas flare/vent system
  - Metering
  - Downstream power scavenging (interface with pressure let-down system)
  - Local environmental and regulatory permits

Technology Status

EnerSea completed a VOLANDS Feasibility Study in cooperation with Duke Energy which resulted in a feasible and cost-effective design. EnerSea has since further developed and refined the system to be constructed either in a horizontal or a vertical orientation depending on siting requirements. EnerSea has recently begun formal marketing of the VOLANDS systems to clients worldwide. EnerSea also applies the VOLANDS gas storage concept as part of the gas receiving facilities in its marine gas transport system in situations where storage is desired. The work performed to date on this technology includes the following major milestones as provided by EnerSeas LLC:

Conceptual Engineering

EnerSea worked with Paragon Engineering Services, Inc. (PES) and Alan C. McClure Associates, Inc. (ACMA) to perform analysis based on their involvement in the Feasibility Assessments. The first project, Process Systems Concept Engineering, focused primarily on conversions, however, "new build" options were defined for cost estimating purposes.

Hazard Identification Review and Safety Studies

The American Bureau of Shipping (ABS) and Det Norske Veritas (DNV) assisted EnerSea in completing these studies. From the issues identified during the HAZIDs, ABS and DNV indicated there are no issues that would not already be present in any type of large-scale oceangoing gas carrier (LNG, LPG, etc.). Therefore, it is ABS' and DNV's preliminary conclusion that the proposed CNG concept provides for an equivalent level of safety as offered by other types of gas carriers.

Guidelines for CNG Class Approval in Principle

ABS developed guidelines to assist EnerSea during patent development and conceptual engineering and to explain the rules and regulations that would apply to CNG transportation.

From a technology perspective, GTI recommends conducting a field pilot installation of an appropriately sized CNG land based facility at a selected California site and demonstrate the technology's operational features while performing a related economic analysis.

Cold Compressed Natural Gas

Technology Description

CCNG is a denser and "cleaner" version of NG. It is stored at refrigerated temperatures and under pressure. If stored in a closed vessel, the steady state storage conditions of CCNG would be at temperatures of less than –150°F pressures greater than 700 psig. Other CCNG storage and transport options (at warmer temperatures) will yield a lower density CCNG but still significantly denser than line pack at standard pipeline temperatures and maximum operating pressure of that pipeline.

Due to its cryogenic (deeply refrigerated) state, the chemical composition of CCNG needs to be slightly different then "pipeline-quality" NG. In order to avoid forming liquid products that would act like "slush" and "ice", CCNG needs to be dry, with a water content of less than 1.0 part per million (PPM) by volume, and must contain less than 100 PPM of carbon dioxide (CO_2). Heavy hydrocarbons (ethane, propane, butane) need to be within the same limits as in LNG. Thus, CCNG (and LNG) contain 1% more energy than the equivalent volume (SCF) of pipeline NG, because water and CO_2 have been removed. That advantage stays with CCNG/LNG as it is warmed back to normal pipeline conditions.

The clean-up process is well understood. It is a standard and routine part of all LNG plants, generally using molecular sieves and liquid separators. Resultant "off gas" is generally used as fuel for power production in on-site, gas-fired, direct-drive or generator-drive engines, or returned to the pipeline.

The most significant feature of CCNG is its density. Table 33, below, tabulates the densities of natural gas at various pressures and temperatures. The figures on the right hand side are conservative because they do not account for the increased heating value of the cryogenic products (when compared to pipeline NG), due to the absence of water and CO2.

Table 33 Density-Range For Pipeline-Quality Natural Gas

	1	2	3	4	5	6	7	8	9	10	11
USE		Ppipeline		Storage	Vehicles		Storage				
CONDITION	Atmos.	Low-P.	High-P.	High-P.	High-P.	High-P.	Low-P.	High-P.	Warm	Cold	Coldest
NAME					CNG	L/CNG	CCNG	CCNG	LNG	LNG	LNG
Press. (psig)*	0	100	900	2,700	3,600	3,600	700	1,500	50	50	50
Temp. (Deg. F)	+70	+60	+60	+110	+100	+30	-150	-150	-225	-255	-260
Pounds/Cu. Ft.	0.045	0.35	3.1	8.3	11.2	13.5	21.7	22.5	24.8	26.1	26.5
Density of LNG	0.17%	1.32%	11.7%	31.3%	42.3%	50.9%	81.9%	84.9%	93.6%	98.5%	100%
*psi = psig + 14.7											

High-pressure natural gas stored underground at 2,700 psig and +110°F, will have a density of only 8.3 pounds per cubic feet, which is only 31.3% as dense as LNG. Even 3,600 psig L/CNG, a vehicle fuel dispensed from LNG into small high-pressure fuel tanks, is only 13.5 pounds per cubic feet, or 50.9% the density of LNG.

By contrast, -150°F CCNG, at only 700 psig, has a density of 21.7 pounds per cubic feet, or 81.9% the density of LNG. At a storage pressure of 1,500 psig, CCNG has a density of 22.5 pounds per cubic feet, or 84.9% of the density of LNG. CCNG is nearly three times as dense as natural gas stored warm in high-pressure underground storage facilities, and 62 times as dense as pipeline natural gas operating at 100 psig. Due to these density properties, CCNG production, storage and transport become economically viable alternatives.

Figure 66 illustrates the relative densities as a percentage of the "coldest" available LNG, which at 26.5 pounds per cubic feet, is used here as the 100% standard.

Figure 67 compares the density (pounds per cubic feet) of various storage options, and clearly shows (as conditions 7 and 8 in the table above and the figures below) that CCNG fills a “gap” between high-pressure warm gas storage and low-pressure LNG storage.

Figure 66 Density as % of LNG

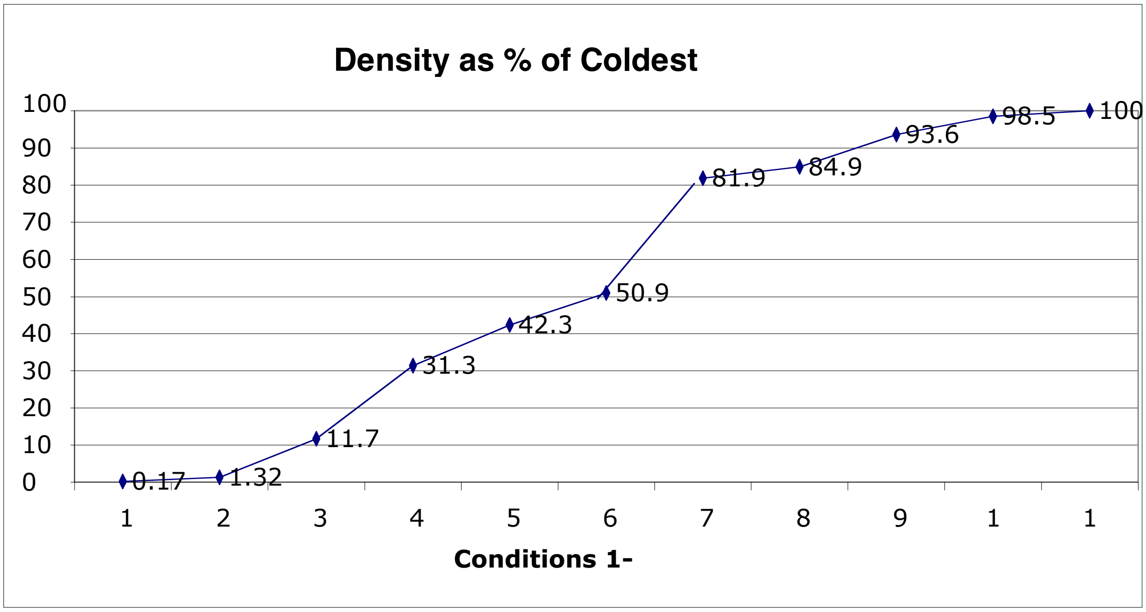
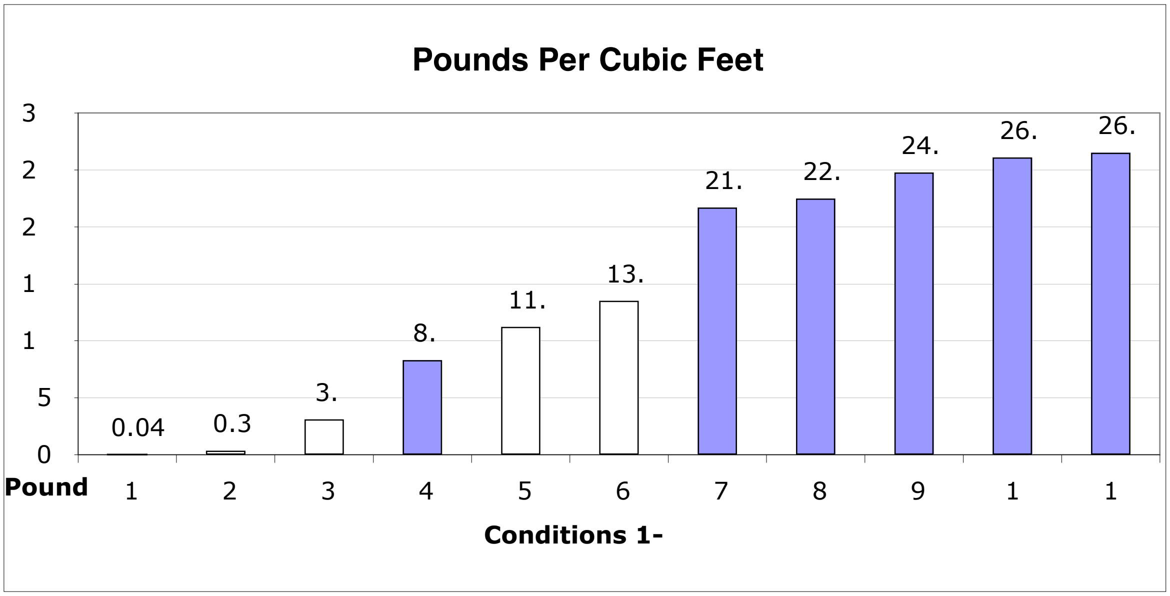


Figure 67 Various Storage Option Densities



At -150°F and colder and at 700 psig and greater pressures, CCNG technology provides an alternative to high-pressure warm gas and low-pressure LNG, offering a new and potentially cost-effective way to store, transport and dispense natural gas. At relatively modest pressures and at relatively "warm" cryogenic temperatures, CCNG offers similar advantages of LNG but without LNG's limitations. Limitations of LNG include: it's too cold for storage in unlined underground caverns; requires approximately 44% more energy input to achieve its moderately higher density; and will always be a two-phased fluid, with a vapor cloud above its liquid state, complicating its storage and transport.

The density of natural gas at low temperatures is exponentially dependent on its temperature, but only arithmetically dependent on its pressure. The highest densities (and the smallest containment volumes) will be achieved by refrigeration, not by compression.

The increased density achieved by refrigeration is also useful in various pipeline transport and storage models at cryogenic temperatures that are warmer than -150°F. This permits the use of CCNG as a "state" of natural gas that can fit into a broad range of cryogenic temperatures and medium- to high-pressures, yielding various densities between standard natural gas and LNG and broadening its application for various storage and transport methods.

The following are additional operating benefits of CCNG:

- A significant portion of the refrigeration energy in CCNG (as measured in billion BTUs) can be recovered and stored during withdrawal from a CCNG vessel to a standard pipeline, which can be used to chill incoming natural gas during the next inflow. By contrast, the compression energy expended and resulting heat generated in natural gas transport or storage (underground storage fields or at pipeline compressor stations) cannot generally be recovered in a practical way.

- Another form of “cold recovery” can use the refrigeration content of the CCNG to pre-cool the inlet air at a power plant, yielding higher efficiency power production and recovering a significant portion of the energy initially required in the CCNG process.
- In addition to “cold recovery” during withdrawal, a portion of the energy required to chill NG into CCNG can be stored in advance of injection in a “working fluid”, thus allowing for faster injection and withdrawal cycles. By contrast, there is no practical way to store the compression required for CNG storage prior to its need.
- The production of CCNG at pipeline compressor stations can take advantage of heat recovery opportunities, like waste engine heat. This energy can contribute to the chilling of CCNG by way of absorption refrigeration.
- CCNG can be contained in aboveground cryogenic pressure vessels, allowing for transport by trucks to remote pipelines, to downstream portions of pipelines requiring supplemental natural gas, and to off-pipeline locations. In this configuration, CCNG systems are generally more efficient than CNG tube trailers and unlike LNG systems, can operate with zero boil-off.
- CCNG can be transported long distances in dedicated pipelines that can be significantly less costly to build and operate than standard pipelines with the same throughput capacity.
- The high-density of CCNG (a “near liquid”) allows it to be pumped rather than compressed, much like standard liquids. That feature allows pumping stations along a CCNG pipeline in lieu of compressor stations, reducing the required energy input and cost to transport the product.

Operational Feasibility

Two specific applications of CCNG will be discussed in this section. The first relates to the process and components of CCNG transport via pipeline. The second is more process oriented and focuses on generation and storage locally for application in the operating scenario evaluation.

CCNG Pipelines

A CCNG pipeline consists of a suitable cryogenic metal, such as 9% nickel steel or certain grades of aluminum, or may consist of certain types of phenolics, Mircata, and other similar composites. A pipeline mayalso be a combination of a liner and a casing, with tolerance for the –150°F and colder conditions and with a hoop strength that would sustain high-pressures. Because of the greater density of CCNG, the diameter of the pipeline would be significantly smaller than that of standard lines with the same throughput. At smaller diameters, the wall thickness of the CCNG line would be thinner than the required wall thickness of standard, larger diameter lines with the same throughput.

In lined (concentric) configurations, the inner material may be pressure rated, providing all of the hoop strength, while the outer layer provides protection for the insulation system between the inner core and the outer shell. That insulation may be of several designs, including a low-grade vacuum between the liner and the shell. In other configurations, the inner liner may fit tight against the shell, with both providing hoop strength as well as a degree of insulation. Additional insulation, such as a micro-sphere wrapping, would further prevent heat gain to the flowing CCNG within.

The CCNG line, regardless of configuration, would exhibit low heat transfer characteristics. The final segment of CCNG lines would be designed with reduced insulation, or none at all, to allow the CCNG to arrive at the standard pipeline to which it is linked at a suitable, non-cryogenic temperature.

Such CCNG lines don't currently exist, but can be constructed with existing technologies. The extra cost of the suitable cryogenic tolerant material, insulation and the labor to install it, would be potentially offset by the following:

- Smaller pipe diameters required to carry the equivalent "volume" of NG, as measured by its BTU content
- Thinner pipeline walls because of the smaller diameters
- Lower pipeline weight (the price of steel and aluminum is directly proportional to its weight)
- Reduced welding requirements, because of the smaller diameters and thinner wall thickness
- Lower shipping costs because of the lower weight
- Smaller trenches and right of way requirements

The simplest configuration would consist of 9% nickel steel (or aluminum), field welded in appropriately sized segments, field insulated, and with very few laterals, emphasizing the line's "point source" nature, as compared to more "local" (warm CNG) lines. An excessive number of laterals will increase costs and heat gain. An optimal deployment will have a starting point and an end point, with no take offs except for pumping stations, and possibly, makeup cooling stations. As a direct line, customers along the CCNG line would be supplied by existing standard lines that would, in turn, be supplied by the CCNG line at only one or two "transfer" points or gate stations, much like existing gas transmission lines.

Some designs may use a composite liner (for its cryogenic tolerance) surrounded by lower-grade nickel steel, acting as a "shell" (for its strength), or by a carbon fiber wrapping. The economic viability of each alternative would vary, and would reflect the total length of the CCNG line, its design capacity (throughput), the frequency of take-off points, the frequency of pumping and re-cooling stations, and other such factors.

More complex configurations, such as liners in concentric configurations, separated by spacers, can transport CCNG in the inner pipe and CNG or a working fluid in the annular space. Such configurations may permit "cold recovery" regimes at the point of transfer from CCNG line to CNG line.

Each CCNG deployment option will need to evaluate the optimum balance between energy use and capital costs. The more complex configurations that achieve cold recovery will reduce the energy required to operate the system but will add to the capital costs. The simpler designs (a model with only the frozen earth as the insulation) will require a much lower capital investment but may cost more to operate.

The following are the implied benefits of transporting and/or storing CCNG locally:

- CCNG is considerably denser than warm natural gas, requiring smaller volumes for storing the same amount of energy, or allowing the same sized storage container to store more energy than any traditional storage or transport option.
- CCNG is a single phased state of natural gas, contained in pressure vessels that have a greater degree of tolerance for pressure then LNG containers, which produce "boil-off".
- In a pipeline, CCNG is kept at pressure by periodic pumping stations, but moves along without the "slug flow" that is produced in LNG lines, where boil-off potentially interferes with liquid flow.
- On site, smaller (local) storage vessels are more easily developed than larger gas storage systems, reducing development time and bringing the storage capacity on line quicker.
- Local storage reduces the cost of transporting the stored NG to the end user and avoids bottlenecks in the pipeline delivery system.
- CCNG can be made from pipeline gas, LNG, stranded gas at non-pipeline quality gas fields, (e.g. flared gas at oil wells), or from some combination of those sources.
- CCNG can be warmed and sent out in standard pipelines, or it can be "flashed" to make LNG.
- CCNG can be transported to and from a storage facility more efficiently in dedicated pipelines, for example, allowing imported LNG to be delivered inland in a high-density form and gasified on site.
- Of all the forms of stored and transported NG, CCNG requires the least energy input relative to the density achieved.

VX Cycle LNG/CCNG Technology

Expansion Energy LLC, the corporation behind much of the CCNG technology development, has also developed a patent pending[9] design for the production of LNG and CCNG, including application at small-scale (local) facilities. This technology is complimentary to that discussed above and has potential application to the operating scenarios identified for the state of California, making it relevant to this research effort.

The cycle is referred to as "VANDORS Expansion Cycle", or the "VX Cycle". The first goal of this process is to facilitate the production of vehicle-grade LNG for bus and truck fleets, with each LNG plant serving a single fleet at its depot, thus avoiding the need to transport the LNG from its production source (usually a large LNG plant far from product's destination) to various end-users. However, the VX Cycle also allows for peakshaving models at any scale, including

[9] U.S. Patent Application No. 11/934,845, for a "Method and System for the Small-Scale Production of Liquid Natural Gas from Low-Pressure Pipeline Gas".

the production of CCNG and production at off-pipeline sources of methane, e.g. stranded natural gas fields.

The VX cycle offers several benefits relative to the issues covered here. For example, it can serve as an on-site peakshaving plant for gas-fired power plants and for other large NG customers, as described in California relevant operating scenarios 1&2. The LNG produced can be pumped, transported and stored as CCNG. Alternatively, the VX Cycle can produce CCNG, but with lower energy costs because CCNG requires less refrigeration input as discussed above.

Existing LNG-fueled truck or bus fleets depend on tanker deliveries from large-scale plants or import terminals, increasing the cost of the product. The customer must maintain a large storage tank at its fueling depot so that frequent deliveries can be avoided. Such tanks produce boil-off which, if vented to the atmosphere, is an unwanted methane emission and constitutes a loss of valuable product.

The relatively low capital cost of the VX Cycle and its high operating efficiency yields a cost effective way to produce LNG (or CCNG) at small-scale plants, with capacities above 2,000 GPD. By contrast, the smallest commercial LNG plant produces approximately 25,000 gallons (95,000 liters) per day. As a point source application, the VX Cycle can be integrated with existing pipeline compressor stations, allowing such facilities to become moderate-scale, distributed natural gas storage sites. As such, those sites could mitigate pipeline bottlenecks, and produce product for off-site use, including as a vehicle fuel or a supplemental source for other nearby pipelines.

A "distributed generation" model for LNG/CCNG production has benefits over the existing model that relies on one or two large LNG plants for production; a fleet of LNG trailers for distribution; and a series of LNG storage tanks and dispensers at each end-user. These benefits of distributed LNG/CCNG production include the following:

- Elimination of the cost of transporting product on roads. Those costs include "internal" costs associated with fueling the trucks and paying for labor, insurance, maintenance, and "external" costs related to traffic congestion, road use and wear, emissions from the trucks and the boil-off during transit.
- By definition, each distributed LNG/CCNG generation site has the capacity to re-liquefy boil-off, which is not the case for the standard LNG distribution model, where the end-user does not typically have re-liquefaction equipment.
- The scale of each facility, including the storage tank, will be significantly smaller, resembling standard fuel service depots, and require smaller profile storage tanks. This is because the tank acts primarily as a "buffer" in the production cycle, rather than a longer-term storage vessel.
- The permitting and financing of smaller facilities with predictable customers (at the site of each location) will be easier than the permitting and financing of a larger LNG plant that requires long term customer commitments in advance of construction.

A prototype 6,000-liter/day VX Cycle LNG plant is being constructed for less than 2.0 million US dollars. The VX Cycle yields approximately 85% LNG from every unit of natural gas that enters the plant, with only 15% of the gas used as fuel for the prime mover (engine or turbine). The VX Cycle assumes that a low-pressure (60 psia or greater) natural gas pipeline or other source is adjacent to the plant site; and with a chemical composition that is pipeline quality (95% methane, with some N2 and CO2, but otherwise "clean" and dry). If the pipeline gas is not clean, there are several known clean up steps that can be integrated with the VX Cycle. Higher-pressure gas feed improves the efficiency of the VX Cycle. Regulation facilities may be necessary for higher pressure sources. These assumptions are readily met by scenarios found within California.

The low-pressure gas stream is separated into a fuel stream (approximately 15%) for the prime mover (engine or turbine), and a product stream (85%) to be compressed and liquefied. CO2 and water are removed in a multi-vessel molecular sieve, which requires periodic regeneration. The regeneration gas is sent to the prime mover for use as fuel. The cleaned gas is then sent to a multi-stage CNG compressor, such as used at existing CNG stations.

The VX Cycle potentially allows existing CNG stations to be upgraded to LNG production. A network of small-scale LNG/CCNG plants can be integrated with existing (sometimes underutilized) CNG stations and possibly with existing pipeline compressor stations.

The feed gas is compressed, in stages, from 60-psia to approximately 400 psia. The CNG compressor is both the feed gas compressor and the recycle compressor. This is due to the VX Cycle being an "all methane" cycle, where the working fluid (refrigerant) and the feed stream are both methane. This is an advance in LNG/CCNG production, as the only LNG plants that now use methane cycles are generally letdown plants. Standard letdown plants (including the small LNG plant at Sacramento) do not require re-compression because they rely on high-pressure feed gas, and have the opportunity to send out large quantities of low-pressure gas into local distribution pipelines. The VX Cycle does not require those special conditions.

The VX Cycle uses an integrated absorption chiller to counteract the heat of compression and pre-cool the CNG immediately after it exits the compressor's after-cooler. Heat of compression is mitigated, and the natural gas is pre-cooled by an absorption chiller powered by waste heat from the prime mover. The engine, chiller, and CNG compressor are linked, each to the other two components, allowing standard CNG equipment to produce cold, moderate pressure CNG.

The VX Cycle exploits the limitations of low-pressure methane compression-to-expansion, without using refrigerants such as N2 in nitrogen expansion cycles, "mixed refrigerants" in MR cycles, hydrocarbons in cascade cycles, and without the inefficiencies of high-pressure Joule Thompson (JT) cycles. Initial tests indicate the cycle can potentially achieve nearly equivalent efficiency of turbo-expander (letdown) LNG plants and without a high-pressure inlet requirement.

Joule Thompson valves and a turbo-expander are then integrated at the back-end to convert the cold CNG into LNG if desired in a particular application. In order to achieve -250°F LNG at 65 psia (or –150°F CCNG at a higher pressure), significantly more refrigeration is needed then can be provided by the front-end chiller. Two sources of refrigeration are incorporated near the main heat exchanger. The first is a throttle valve. The pre-cooled CNG at +/- 400 psia is sent through the main heat exchanger where it is cooled to –170°F by the other streams within the exchanger. That combination of approximately 400 psia and –170°F allows for "plate fin" heat exchangers rather than more-expensive coil wound units.

CCNG may be the end product of the VX Cycle. However, if a colder and denser product is desired, such as LNG, then a portion of the -170°F stream, at +/- 400 psia, is sent through the throttle valve, which yields approximately -254°F vapor and liquid at a pressure of only 19 psia. That cold vapor + liquid stream is used to sub-cool the portion of the stream that is still at -170°F and 400 psia, cooling it to -251°F and still at +/- 400 psia. The sub-cooled product is dropped in pressure to 65 psia; forming LNG at -250°F, which can be sent to the storage tank, without any "flash" (vapor) formation. Various options exist for the final storage temperature and pressure of the LNG (or CCNG) depending on the intended use for the product.

The low-pressure stream that cooled the main product stream in the sub-cooler is returned to the beginning of the process as part of the recycle stream. Prior to its return through the main heat exchanger, the recycle stream is mixed with the recycle stream from a compressor-loaded cryogenic methane turbo-expander – the second source of refrigeration referenced above. The turbo expander is needed because Joules Thompson refrigeration is not efficient enough. The expander converts cold CNG to colder, lower-pressure natural gas. Expansion Energy has identified a US maker of highly efficient, affordable, gas-bearing, compressor-loaded, cryogenic expanders for this application.

Both the throttle valve and the expander function well with the 400-psia inlet pressures. The 400 psia is a "comfortable" inlet pressure for a small expander. The selected refrigeration methods, and the conditions at which they operate, potentially yield a desirable balance between refrigeration produced, the size and temperature of the recycle stream, the workload of the CNG compressor, and the total LNG/CCNG produced per unit of fuel used to run the plant.

Much of the previous LNG/CCNG technology discussion evaluated potential configurations of the technology and its potential implementation benefits. The following discussion focuses on the technologies specific application to the operating scenarios 1, 2, and 3 identified by California investor owned utilities SoCalGas and PG&E.

This analysis includes the following assumptions for each operating scenario.

- Local production of LNG/CCNG – a distributive model – will alleviate the peak period throughput demand on the associated distribution and transmission pipeline grid
- Small- and moderate-scale storage options in above ground vessels and as pipeline configurations will facilitate the delivery of the stored NG to the customer, bypassing bottlenecks, reducing transport costs and eliminating the conflict between pipeline capacity and the need to deliver peak volume product from distant, large-scale storage facilities;
- Distributed production and storage systems will operate with lower losses and will use less energy to deliver the stored product to the customer
- Existing amortized equipment at power plants and compressor stations would be utilized when possible, reducing the capital investments required for such new facilities

Operating Scenario 1

The most efficient long-term CCNG/LNG technology application to Scenario 1 is a comprehensive configuration. As discussed in Section 4.1.3, the electrical generation plant would function continuously, with peak day demand requirements primarily during the daytime, or approximately 6:00 AM to 8:00 PM. Off peak hours provides the ability to re-direct a portion of excess pipeline capacity toward the production of LNG/CCNG to essentially recharge the storage capacity for delivery the following day.

The optimal size of the VX Cycle LNG/CCNG plant will need to account for the limits (if any) on the size of the on-site LNG storage tanks. At this time, CCNG cannot be stored cost-effectively in large aboveground storage vessels. Therefore, subsequent analysis will address LNG production and storage utilizing the VX Cycle. Please note that application of CCNG production and storage would be very similar to LNG in this case and would be substituted in the future when commercially viable.

As described in operating scenario 1, it is estimated that approximately 2 MMcf/hour of natural gas would be required to meet peak day demand requirements and fully supplement/replace existing pipeline gas. Of this peak day system demand, the installed systems would be designed to supplement approximately 50% of the volume. This relates to a total deliverability of 14 MMcf/d (170,000 gallons of LNG) of natural gas that would be available to serve other customers in the associated distribution system, or meet any on-site electrical generation plant requirements.

For this operating scenario, with a 60,000 GPD VX Cycle LNG plant on site, approximately 20,000 gallons would be produced during off peak hours. The 20,000 gallons (or more) produced during the off-peak period in conjunction with four 75,000 gallon storage vessels would allow the system to function for 2 consecutive days under peak day demand conditions.

Operating in that mode, the power plant will enhance the economic value of its power output (by leveraging off-peak price arbitrage opportunities) and will increase its daytime efficiency by the use of cold inlet air to the prime mover.

Operating Scenario 2

For operating scenario 2**,** a system very similar to that recommended in the previous scenario would be utilized. This scenario is focused on addressing situations in a transmission or distribution system where infrastructure limitations are causing a lack of reliable or adequate gas supplies in peak day demand conditions.

The system proposed, including an adequately sized VX Cycle LNG/CCNG facility and storage vessels, would be installed ideally at a compressor station downstream from the bottleneck, and deliver supplemental natural gas directly into the transmission line. The proposed system would be comprised of:

- Two 60,000 GPD VX Cycle LNG/CCNG facility
- Approximately twelve 75,000 gallon storage vessels

Another alternative configuration, which may be several years from commercialization, would bypass potential system bottlenecks and provide sufficient supplemental natural gas by way of a CCNG pipeline. This would allow for a higher rate of delivery to San Diego or other regions which may experience deliverability issues due to infrastructure limitations. As discussed previously, preliminary estimates indicate that such a CCNG pipeline would be substantially less costly to build and operate then an equivalent capacity standard pipeline. However, a more detailed economic analysis would be required. More discussion of the benefits and operational specifications of CCNG pipelines can be found in the appendix.

Operating Scenario 3

Operating scenario 3 is designed to supply residential or commercial customers natural gas during planned and unplanned pipeline outages. These would require mobile, highly portable systems, such as truck mounted storage tanks, with accompanying small scale facility installations that would be strategically located in high population density areas or those areas with known infrastructure limitations during peak demand periods. To simplify this application, deliverability will be scaled based on an outage comprised of 1,000 residential customers in a peak day demand scenario. It is assumed each residential customer is utilizing 80% of the throughput of a typical gas meter, or 200 scf/hour and the outage is expected to last 24 hours. This relates to operating parameters of:

- Approximately .200 MMcf/hour deliverability, for 24 hours, into a 60 psig distribution line.
- Total volume required to meet outage parameters is 57,000 gallons of LNG

This operating scenario is currently being addressed with portable CNG trailer systems. A CCNG-based solution becomes very attractive in this scenario due to the inherent inefficiencies of delivering CNG in tanks (or tube trailers). Based on the operating parameters, an outage of this magnitude, or 1,000 residential customers during peak day demand conditions, could be serviced with just 2 or 3 appropriately sized vehicle/trailers delivering CCNG or LNG to the site. This assumes reasonable travel times between the site and the refueling station.

Transport vehicles for LNG delivery are commonly available. A CCNG delivery truck is not yet commercially available. However, it would be very similar to an LNG trailer, but with the capacity to contain the higher-pressures of CCNG. Additional benefits of a CCNG delivery system would include lower production cost, instantaneous pressure at the delivery site, and no boil-off.

When this particular system is not being utilized for outages as outlined in operating scenario 3, each of these small-scale CCNG plants could produce product for the Alternative Fuel Vehicle (AFV) market (including for vehicles that serve California's ports) or for off-pipeline demand such as rural markets now served by propane. Such off-pipeline markets would include the large areas of California that are not served by natural gas pipelines. With natural gas costs at approximately 50% of the cost of diesel or propane (on a BTU equivalent basis), the off-pipeline sale of LNG/CCNG can be a viable business and an effective tool for increasing the use of natural gas.

The AFV market would also include farm equipment and other off-road vehicles, and generators, such as those that serve irrigation systems. The "emergency" supply purpose of such distributed generation LNG/CCNG plants would be augmented by a steady outflow of clean fuel for non-emergency uses. That multi-purpose approach yields faster amortization rates on the cost of the plant and will make them more economically viable long term.

Safety and Permitting Considerations

The production, storage and transport of CNG and LNG are well-developed technologies with no particular public safety issues, other than those normally associated with any hydrocarbon system. Existing state and national standards adequately address the safety of the natural gas infrastructure, including the innovations outlined above. However, some aspects of the solutions discussed in this report will need further review to see if there are any gaps in those safety standards relative to the proposed technology.

The small-scale production of LNG, by the VX Cycle is well within existing safety protocols. The production of CCNG is also covered by standards for cryogenic pressure systems. The deployment of the first CCNG pipeline may require additional discussion with FERC and other reviewing entities. A successfully permitted and deployed short run "prototype" providing local, rather than national service, could pave the way for more ambitious deployments that would follow.

Similarly, a CCNG delivery tanker would be an enhanced version of existing LNG, LOx and LN_2 tankers, but with a pressure rating of above 700 psia. Certification of such a tanker by the appropriate California and federal agencies may require additional time and review.

Economic Feasibility

From a broad perspective, the investment in new LNG/CCNG systems can yield several potential economic benefits in addition to providing point source natural gas deliverability. Example include:

- Several of the distributive LNG/CCNG models discussed could help increase the penetration of LNG/CCNG/CNG in the AFV market and in off-road mobile and stationary equipment, displacing other, less clean fuels.
- Distributive LNG/CCNG systems can also replace other fuels now used for non-vehicular service in portions of the state that are beyond the pipeline network.
- Existing stranded gas fields (beyond the economic distance for a standard pipeline connection, or with non-pipeline quality gas) can become cost-effective in-state sources of natural gas.
- The flaring of associated gas at existing and future oil wells can add another economically viable NG source, while reducing the emissions of flaring and utilizing a formerly wasted resource.
- Under some circumstances, the production of LNG/CCNG may be a higher-value solution to energy recovery at landfills than the production of power.
- Similarly, a distributive LNG/CCNG network can use anaerobic digester gas (ADG) as a feedstock, yielding a high-value storable and transportable product.

As potential deployments of the LNG/CCNG systems increase, equipment costs will drop, design and permitting issues will become more routine, and public acceptance will increase, all of which will enhance the economic viability of each component of a growing LNG/CCNG network.

Given the lack of commercial applications, all costs are estimated and supplied by Expansion Energy LLC. The following offers cost estimates for some of the specific components discussed above, including different scaling scenarios. Futher analysis will provide cost estimates focused on the operating scenarios outlined above.

- Shop fabricated LNG storage tanks:
  - One 75,000 G tank at +/- $750,000 plus $150,000 for installation
  - Two 75,000 G tanks, for a total capacity of 150,000 G, at +/-$1,500,000 plus $250,000 for installation
- LNG trailer: +/- $350,000
- CCNG trailer: +/- $450,000
- VX Cycle LNG/CCNG plant:
  - 10,000 GPD at $3,000,000;
  - 20,000 GPD at $4,750,000;
  - 40,000 GPD at $7,500,000;
  - 60,000 GPD at $9,750,000.
- CCNG pipeline at equal throughput of an equivalent standard pipeline: 20% to 50% lower cost, depending on total lengths.

Operating Scenario 1

Cost estimates of a single installation in relation to operating scenario 1 would be as follows:

- Approximately $9,750,000 for a 60,000 GPD VX Cycle LNG/CCNG plant, plus approximately $3,500,000 for installed storage vessels, for a total cost of $13,250,000.
- Operational costs would be relatively minimal in relation to capital expenses with the facility fuel costs the most significant component. The 10% to 15% fuel usage requirement would require the value of the produced supplemental gas (85% to 90% of system inlet gas) be valued considerably higher to offset the cost of inefficiencies. Peak day deliverability of this supplemental gas will provide this economic advantage and improve this system's viability.

Operating Scenario 2

LNG/CCNG technology application to operating scenario 2 is very similar to scenario one, and similar capital and operational expenses would be incurred on a larger scale.

- Approximately $19,500,000 for two 60,000 GPD VX Cycle LNG/CCNG facilities
- Twelve 75,000 gallon vessels (900,000 gallons) at $9,000,000 for 900,000 gallons of storage capacity, plus an estimated $750,000 in installation costs for a total $29,250,000.

Another alternative previously discussed, which may be several years away from commercialization, would bypass potential system bottlenecks and provide sufficient supplemental natural gas by way of a CCNG pipeline. This would allow for a higher rate of delivery to San Diego via the Rainbow Station or other regions which may experience deliverability issues due to infrastructure limitations. Preliminary estimates indicate that such a

CCNG pipeline would be substantially less costly to build and operate then an equivalent capacity standard pipeline. However, a more detailed economic analysis would be required.

Operating Scenario 3

Cost estimates for operating scenario 3 assumes that three strategically located 10,000 GPD, distributed VX production plants are implemented to provide supplemental natural gas in emergency or outage scenarios. Mobile, trailer mounted storage units would then transport the LNG/CCNG from the facility installations to the sites, delivering sufficient volumes of gas and minimizing the number of vehicles/tankers required to maintain service to impacted locations.

- Three plants integrated with existing compressor stations, each at an approximate cost of $3,000,000 plus a 75,000 gallon storage container at each location costing $900,000 installed, and would total approximately $11,700,000 for the installed production and storage network.
- LNG /CCNG mobile units would be comparable to the cost of existing CNG units. Additional on board equipment costs would be off-set by less expensive lower pressure tanks required for CCNG storage.

Costs associated with the operating scenarios are summarized in the following table.

Table 34 Operating Scenario Cost Summary

	VX Cycle Facility Cost	Storage Vessel Cost	Total Capital Cost
Operating Scenario 1	$9,750,000	$3,500,000	$13,250,000
Operating Scenario 2	$19,500,000	$9,750,000	$29,250,000
Operating Scenario 3	$9,000,000	$2,700,000	$11,700,000

Due to the lack of commercial development, more detailed operating costs cannot be determined at this time. Further development and pilot installations will be required to prove economic viability.

Technology Status

GTI has worked closely with Expansion Energy LLC to define the next research, development, and deployment steps necessary to bring the various CCNG technologies to commercial viability.

CCNG technologies have undergone significant research and development and are well positioned to transition into a demonstration stage.

CCNG Pipelines

The next step in developing a CCNG pipeline system would be to identify select locations where one- to five-mile CCNG pipeline extensions would potentially solve local delivery problems, such as bottlenecks in the system. Based on locations identified, one should be selected for a field demonstration/trial. The criteria for selection would include several factors, including the following:

- Availability of a right of way;
- Upstream and downstream capacity to feed the new CCNG line and to receive product from it;
- Availability of a modestly sized property (say, 10,000 sq. ft.) for the installation of the CCNG production monitoring equipment;
- An appropriate land use context near the production / monitoring site and along the route of the CCNG pipeline;
- Community support for the demonstration.

The primary objective of a demonstration would be to apply the various CCNG technology components discussed in this report to a specific operational environment and monitor the performance of the complete system. In order to ensure the highest likelihood of success, the selected pilot project should not be excessively ambitious. For example, a shorter run would allow for easier monitoring, would reduce the issues related to pressure drop and heat gain, and generally reduce the number of variables.

Expansion Energy LLC has identified 9% nickel steel, aluminum, and certain filament wound tubing as appropriate CCNG pipeline materials. Each has a long history of use in cryogenic applications, including piping.

The extent of insulation, and the selected methods, could vary from the latest micro-sphere technology to using no insulation at all. The latter option may be appropriate if the CCNG needs to arrive at its destination at above-freezing temperatures.

The selected demonstration would allow the gas pipeline company to potentially mitigate a local infrastructure bottleneck, test performance of some aspects of the CCNG technology, and navigate the certification and permitting issues associated with the deployment of a new type of pipeline.

VX Cycle

The VX Cycle has undergone preliminary testing and is suitable for a wide range of field deployments at various scales. It may be demonstrated in conjunction with a CCNG pipeline application or as a stand-alone field trial.

Similar to the proposed CCNG pipeline demonstration, a location should be selected to validate key VX Cycle operations and parameters such as:

- Short term peakshaving;
- Pipeline pressure maintenance and emergency supplies of NG;
- Product to off-pipeline customers, replacing non-NG fuels;
- Product to AFVs.
- The scale of the facility is recommended to be above 5,000 gallons per day and less than 30,000 gallons per day, allowing it to have a commercially viable scale but well below the standard LNG peakshaving plant size.

Of that preliminary group of candidate sites, we recommend one application be selected for advancement. Site selection criteria provided by Expansion Energy LLC would include several factors:

- Consistent availability of pipeline gas at pressures above 60 psia;
- Proximity to a "customer base", such as AFVs, off-pipeline users, or existing pipelines that routinely experience pressure drops and capacity shortages;
- Availability of a modestly sized property (say, 10,000 sq. ft.) for the installation of the VX Cycle production equipment and for the equipment that will monitor the demonstration;
- An appropriate land use context near the production / monitoring site; and
- Community support for the demonstration.

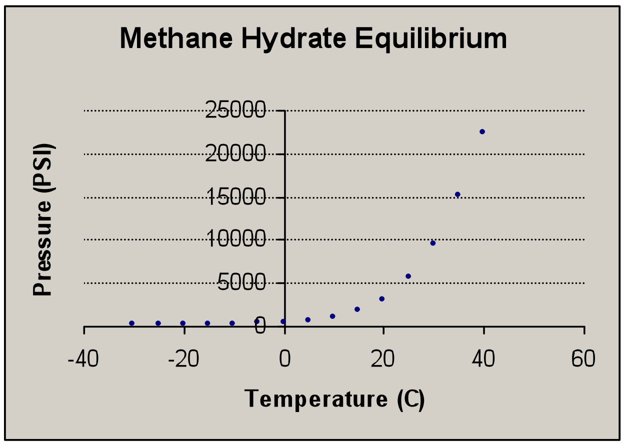
In summary, the selected VX Cycle demonstration will allow the gas pipeline company (the sponsor) to potentially solve a set of local issues, demonstrate the VX Cycle, and gain experience in generating community support for the distributed production of LNG and/or CCNG.

Advanced Natural Gas Hydrate Storage

Technology Description

Natural gas hydrates (NGH) are crystalline substances composed of water and gas in which a solid water lattice accommodates gas molecules in a cage like structure that is in solid state at -20° C temperature and atmospheric pressure (Figure 68[10]) and contains methane up to 170 times its volume. Note that although some dissociation happens at -20° C, the release of gas is inhibited by the self preservation phenomenon due to the formation of a thin ice layer on hydrate crystals hampering the heat transfer process[11].

Figure 68 Methane Hydrate Phase Equilibrium Diagram



Physical properties, simple storage requirements, and low risks make the NGH an attractive transportation and storage alternative as compared with LNG where the temperature is maintained at about -162° C and the risk of spill is a major concern. In addition, production and gasification of NGH is more efficient in comparison with liquefaction and gasification of LNG by as much as 18 to 25%[12]. These conditions lead to lower overall cost and lower environmental impact because as less energy is consumed for the process, less carbon dioxide is produced (thus less greenhouse gas emissions).

Another factor that adds to the attractiveness of NGH storage stems from the fact that the water produced during gasification (hydrate dissociation) is low temperature fresh water that can be used for a variety of cooling operations. In practice, pressurized dissociation can occur at any point to the right of the curve on Figure 68. For example, at 615 psi pressure the equilibrium temperature is about +5° C. Setting the temperature to above +5° C and the pressure below 600 psi, methane is released and the water is in liquid phase. Naturally, any pressure-temperature pair to the right of the curve results in the same condition.

Operational Feasibility

---

[10] Calculated using Professor Sloan's hydrate equilibrium calculation program. E. D. Sloan, Colorado School of Mines, 1996.

[11] Satoshi, T, Chemical Engineering Science , Volume 60, Issue 5, March 2005, Pages 1383-1387

[12] Kanda, H Proceedings of the 23rd World Gas Conference, Amsterdam 2006

The use of natural gas hydrates as a peak shaver in storage operations would entail creating the hydrate at or near a candidate high consumption point of use, or at a storage sites, in off-peak periods and gasification during the high demand times. Alternatively, the NGH can be produced at a plant near the source (producing field, compressor station, or processing plant) and transported on land to a storage unit at a conventional storage site or at a point of high consumption such as a power plant or a smelter.

Mitsui Engineering and Shipbuilding Company of Japan studied the use of NGH for land transportation and delivery to remote communities. This latter case would compare to the use of NGH created near the source and transported to a storage field on land. Mitsui has built and tested a pilot unit capable of producing pelletized NGH at the rate of 600 kilograms per day.

Figure 69 Photographs of NGH pellets produced by Mitsui Engineering

In fact, Mitsui has established a company (NGH Japan) "aiming to raise the NGH technology to supply 10 million metric ton/year (LNG equivalent) of natural gas to global consumers in 2020-2030. To achieve this, NGH sets the milestone in approximately 2012-13 as the time for the transition to commercialization of NGH supply chain project and is planning to conduct the feasibility study and implement the pilot project to demonstrate the marine transportation and scale up the technology with some strategic partners[13]." In the meantime, Mitsui's pilot project for on-land transportation and gas delivery using NGH is expected to be completed in 2008[14].

Development of NGH production plants has been underway for nearly a decade. Mitsui Engineering and various partners have reported a pilot unit (**Figure 70**) capable of producing 600 kilogram per day of pelletized NGH. They have also reported their plans to build an NGH plant at Japan's Yanai power station for production of NGH at 5 tons per day using the surplus cold heat from LNG gasification.

Figure 70 NGH Production Pilot Unit at Chiba, Japan

[13] Mitsui news release, April 19, 2007

[14] Mitsui news release, June 9, 2006

NGH Experiment Plant (Chiba Factory of Mitsui Engineering & Shipbuilding Co., Ltd.)
NGH Production: 600kg/day

In the meantime, Rudy Rogers et. al at Mississippi State University carried out a bench scale and a pilot scale study aimed at characterization of formation and dissociation of natural gas hydrates as a storage medium. The pilot scale experiment was in an outdoor pilot and included a 72"x32" reaction vessel in which hydrates of pure methane, methane and higher hydrocarbon gas mix, with and without surfactant were produced[15]. The work at Mississippi State University did not include pelletization, rather, hydrates were formed on the surface of heat exchanger fins and grew outward until the reaction cell was filled. These experiments proved the feasibility of NGH formation and dissociation as a storage mechanism.

The work at Mississippi State University is directed toward proving the feasibility of natural gas hydrates as a storage mechanism for point source applications. Though successfully completed specific bench scale studies, it is premature to apply the technology to the operating scenarios described in this report. Further development is required prior to conducting operational feasibility for specific applications.

Economic Feasibility

Economics of NGH for transportation as an LNG substitute has been studied in detail by Mitsui Engineering and Shipbuilding Company of Japan for more than a decade. Mitsui Engineering has concluded that the NGH economics surpasses that of the LNG for short hauls and offers a safer and environmentally friendlier alternative.

At this point in the development of NGH technology for application in a "dispersed" environment for purposes of this analysis, potential economics have not been established and therefore cannot be evaluated at this time.

[15] Advances in the Study of Gas Hydrates, edited by Taylor, c. and Kwan, J.

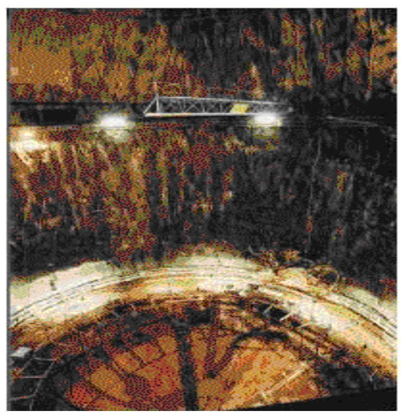
Lined Rock Cavern

Lined Rock Cavern technology has been included in this research due to its potential applications in various scenarios. Specifically, in regard to California, all that is required is a competent bedrock for the man-made facility to be implemented. This geological constraint has not been fully investigated in California, and more importantly has not been excluded from potential application.

Technology Description

Utilization of Lined Rock Caverns (LRC) that could be created in mine tunnels, mine shafts and other excavated spaces for natural gas storage has been studied in detail during the last two decades. The Swedish company LRC has been the frontrunner of the development efforts in this arena. In essence, the technology is viewed as a substitute for salt cavern storage in areas where no substantial salt domes or layers are present in the geologic section and provides for quick withdrawal during the peak periods. The LRC involves using the existing or excavated caverns in hard rocks and lining the cavities with steel and concrete for withstanding high storage pressures. The concept of chilling the gas, thereby increasing the storage capacity, may also add to the LRC features.

Figure 71 Rock Cavern Under Construction at Skallen, Sweden



The LRC technology has been under development in Sweden by Sydkraft since 1987. The development process has included extensive technical studies, laboratory testing, and field tests. The first lined rock cavern for storage of gas under high-pressure has been constructed at Skallen, Sweden and was put in service in 2004[16]. The facility includes a 40,000 cubic meter storage silo built 115 meters below the surface and features a one kilometer long access tunnel. The maximum gas pressure is maintained below 2900 psi. Construction of the site is depicted in Figure 71.

Operational Feasibility

Since the mid 1990s, the US Department of Energy has pursued the LRC concept through several research projects aimed at determination of viability of LRC as a peak shaving facility. Results from these efforts, particularly from project DE-AC26-97FT34348 (Commercialization Potential of Natural Gas Storage in Lined Rock Caverns) and DE-AC26-97FT34349 (Advanced

---

[16] CAT.INIST web page

Underground Gas Storage Concepts, Refrigerated Mined Cavern Storage) have been very promising, indicating that LRC may in fact be a favorable storage alternative under the right geologic conditions.

As mentioned earlier, the LRC gas storage system is viewed as a substitute for salt caverns. The US Department of Energy has identified five regions that have not had favorable geological conditions for underground salt cavern storage development: New England, Mid-Atlantic (NY/NJ), South Atlantic (DL/MD/VA), South Atlantic (NC/SC/GA), and the Pacific Northwest (WA/OR). California was not part of this particular research effort, but also exhibits non-favorable geology for salt cavern development, making it a potential candidate for LRC.

In late 1997, the Federal Energy Technology Center (NETL) of the United States Department of Energy (USDOE) engaged Sofregaz US to investigate the commercialization potential of natural gas storage in Lined Rock Caverns[17]. Sofregaz US teamed with Gaz de France and Sydkraft, who had formed a consortium called LRC, to perform the study for the USDOE. Results of this study became available in 1999.

The Itasca Consulting Group LLC performed a comprehensive study of LRC dealing with investigation of rock and liner deformations for LRC and included elaborate modeling and analytic analyses of expected strain resulting from pressurization of cavities. Results from these studies are available in their final report[18].

To date all studies of LRC concept have been focused on caverns in hard and competent rocks such as igneous rocks and hard carbonates. This is due to the fact that the steel liner is considered as a sealing material and not a confining material. Typical design parameters used in these studies assume cavities between 20 m to 50 m in diameter, 50 m to 115 m tall at depths of 100 to 200 m below the surface. The steel liner would be 12 to 15 mm thick and attached to the cavern surface by a thick concrete layer separated from the liner by a thin and flexible bituminous layer.

Studies by Itasca Consulting Group (Ref. 14) include results from elaborate computer simulations investigating the response of cavity and steel liner under numerous in situ and variable conditions. This document provides a comprehensive set of performance requirements for the overall design of the steel liner, required documentation, material requirements for steel plate and filler material, erection, welding and inspection. The approach adopted for these studies addresses the rock/liner/sealant interactions and as such, can be adapted as a general guideline for any future study on LRC design. However, the group recommends that: "The technical documentation for potential LRC projects in the United States needs to be rewritten to reference appropriate U.S. codes and specifications and to avoid duplication of the provisions. It is not clear which U.S. standard should govern the design. It is our recommendation that the AISC design specifications be cited in lieu of the ASME Boiler and Pressure Vessel Code if there

---

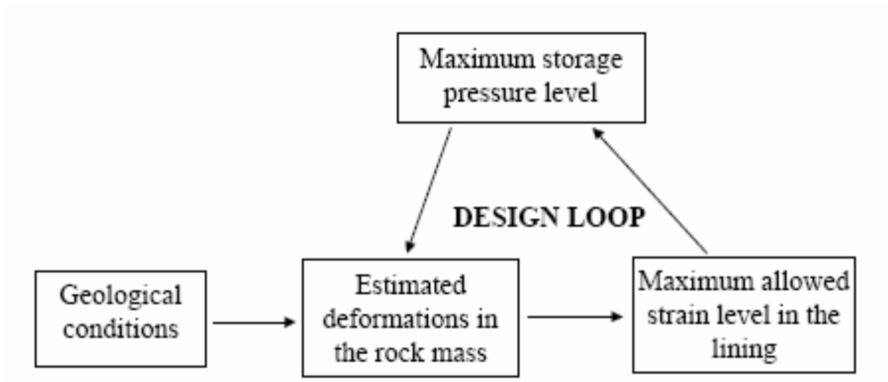
[17] Commercial Potential of Natural Gas Storage in Lined Rock Cavities, Final report, November 1999

[18] Technical Review of the Lined Rock Cavern (LRC) Concept and Dsign Methodology: Steel Liner Response, DE-AM26-99FT40463, Subcontract No. 735937-30001-02, 2002.

is a choice and if it is required to cite a design specification. The LRC concept seems feasible from the standpoint of the structural integrity of the steel liner. However, we recommend that analysis be conducted paying more attention to details, particularly the effects of discontinuities in the rock mass and the shear resistance of the bituminous layer between the steel liner and the concrete."

Note that the steel liner functions as a seal and the pressure exerted by stored gas is held by rocks in which the cavern would be excavated and as such, the rock's mechanical properties, presence or absence of heterogeneities, fractures, and fissures are the most influential parameters determining the feasibility of candidate LRC sites. The schematic diagram on Figure 72 shows the modeling approach for technical evaluation of an LRC storage site.

Figure 72 Modeling Approach for Evaluation of LRC Sites



One of the problems associated with LRC is periodical temperature changes in the stored gas. In the case of injection, compressing the gas into the storage causes the temperatures to rise reducing the effective storage volume and in withdrawals the temperature would fall and may even reach to below 0^{o} Celsius. It is expected that these cyclical temperature variations could alter the mechanical properties of the steel lining, the flexible bituminous layer, and the surrounding concrete layer leading to a possible failure. To prevent these cyclical temperature changes, it is proposed that the storage be cooled during injections and heated during the withdrawals for maintaining the temperature at an acceptable range. The study of one system by Sofregas (Ref. 15) concluded that by adding a cooling/heating system to the LRC, the working gas will increase by approximately 30 percent with the circulation system compared to an unheated/un-cooled LRC storage system.

A lined rock cavern offers an attractive on-site peak shaver storage facility by providing safe and rapid injection/withdrawal cycles that can be repeated many times during the season. The most critical parameter impacting the selection of the system for a given power plant is the local geology. The presence of a thick competent layer of geologic formation such as dense limestone, sandstone, granite, or other igneous or metamorphic rocks at shallow depths is a definitive prerequisite.

Operating Scenarios 1 and 2

Ignoring gas compressibility and assuming constant temperature, the needed cavity capacities for injection/withdrawal volumes of 2 and 3 million cubic feet per hour for 12 and 14 hours per day with 25% additional space for base gas under 3000 psi storage pressure are shown on Table

35, perating cenario (OS) 1. Similarly, the total cavity volume needed for 12 to 15 hours per day at 4 and 5 million cubic feet per hour are shown on operating scenario (OS) 2.

Table 35 Minimum Required Cavity Volume for Given Withdrawal Rates

OS 1

Rate in million scf per hour	Inject/withdraw period, hr/day	Total standard volume (MMcf)	Cubic feet of needed cavity space (Assume 3000 psi storage pressure)	25% base gas	Total needed cavity space (cf)
2	12	24	116,000	29,000	145,000
2	14	28	135,333	33,833	169,167
3	12	36	174,000	43,500	217,500
3	14	42	203,000	50,750	253,750

OS 2

Rate in million scf per hour	Inject/withdraw period, hr/day	Total standard volume for 12 hr (MMcf)	Cubic feet of needed cavity space (Assume 3000 psi storage pressure)	25% base gas	Total needed cavity space (cf)
4	12	48	232,000	58,000	290,000
4	15	60	290,000	72,500	362,500
5	12	60	290,000	72,500	362,500
5	15	75	362,500	90,625	453,125

The above calculations assume that the pressure would be allowed to fall by nearly 75% of the maximum in a withdrawal cycle. This and other simplifying assumptions are meant to give rough estimates of the needed cavity volumes and should be viewed only as ballpark estimates.

Economic Feasibility

Because of the attractiveness of LRC as a peak shaving option, economic aspects of LRC storage were also studied in detail by Sofregaz/LRC (Reference 13). The referenced studies concluded that there is a potential for commercialization of the LRC technology in the United States. Two regions were studied in some detail - the Northeast and the Southeast. The investment cost for an LRC facility in the Northeast was estimated at approximately $182 million and $343 million for a 2.6- billion cubic foot (bcf) working gas facility and a 5.2-bcf working gas storage facility respectively. The relatively high investment cost has been attributed to be a strong function of the cost of labor in the Northeast. The labor union-related rules and requirements in the Northeast result in much higher underground construction costs than might result in Sweden, for example. Note that the costs used in these studies are in late 1990s dollar and gas prices and simple escalation by inflation rate would not be necessarily correct.

In light of these estimates, it appears that under favorable geologic conditions, creation of a lined rock cavity for either direct feed to a power plant or for line packing would be possible.

Technology Status

Lined Rock Cavern technology is relatively straight forward and thoroughly researched for potential feasibility and application. An initial site has been completed in Sweden and has been operational for a few years. There have been no installations or pilot demonstrations in the United States though preliminary studies have identified several potential applications. These applications would be applicable to California if geological considerations are met.

The next step in implementing this technology is to perform detailed geological engineering studies for specific applications within the state of California and if feasible, initiate a pilot test.

4.3 Conclusions and Recommendations

Adsorbed Natural Gas

There are currently no commercial installations of large-scale ANG technology in operational gas distribution or transmission networks, though economic estimates suggest that it could be viable for specific situations in the future. There are a number of areas where improvements to the technology could be made to improve this viability further, and most of these should be realized within a 5 to 15-year timescale. Recommendations for further development and implementation of ANG technology include the following:

- ANG technology is close to being field applied with a pilot diurnal storage demonstration plant planned for installation on a real network. Completion of this demonstration as well as initiation of similar pilots for other operating scenarios is the logical next step in providing tangible evidence of its flexibility and economic feasibility
- The technology gaps identified for commercialization in the next 5 to 15 years include:
    - Carbon and adsorbent improvement to achieve higher storage capacities
    - Heat transfer management to improve the storage efficiency
    - Vessel inspection regime to minimise disruption to the operation
- ANG mobile storage as backup supply during network disruption is ideal to demonstrate the full capabilities of an ANG system. With the high-pressure inlet gas and low-pressure distribution discharge points available, ANG has advantages over storage solutions such as LNG and CNG for its modular construction, process simplicity, low CAPEX and OPEX (no compression is needed), as well as good safety performance.
- As shown in the economic estimates, initial capital and operating costs associated with large scale ANG applications are significant and until further process advancements are made, they are most likely prohibitive.

Small Scale LNG Technology

As noted in the previous section, the scenarios considered for this study is unique compared to common LNG peak shaving facilities and their operation. Although the liquefaction and vaporization rates are not uncommon, the relatively short (30 day) cycle time requires LNG tank sizes that are between the largest factory-built units and the larger tanks typically used in LNG peak shaving facilities. These have cost implication, but are not technological barriers.

GTI recommends no further research and development at this time.

Compressed Natural Gas

EnerSea LLC has developed the VOTRANS technology, a ship based CNG transport similar in concept and technology to land based version VOLANDS, over the last seven years, with various companies providing support and technical studies throughout this period.

Also completed was a VOLANDS Feasibility Study in cooperation with Duke Energy which resulted in a feasible and cost-effective design. EnerSea has since further developed and refined the system to be constructed either in a horizontal or a vertical orientation depending on siting requirements.

Economic analyses of the system applied to the operational scenarios indicate relatively significant capital expenses and further analysis is recommended for specific applications.

GTI recommends additional field pilot installations of an appropriate size at a selected California site to demonstrate the technology's operational features and perform a related economic analysis. Given the facility siting requirements, it may be difficult to strategically locate facilities for intended application as well, but should be investigated.

Cold Compressed Natural Gas

CCNG based technologies, from a process perspective, have undergone significant research and development. This includes the VX Cycle as well as preliminary investigation into pipeline materials for transport applications. As there have been no field installations or demonstrations to date, it is difficult to ascertain economic viability of the technology.

The recommended next step in further developing CCNG technology is to initiate a field pilot study/installation. The primary objective of a demonstration would be to apply the various CCNG technology components discussed in this report to a specific California operational environment and monitor the performance of the complete system.

Natural Gas Hydrates and Lined Rock Caverns

Analysis of the background technologies suggests that both NGH and LRC are viable storage concepts for short-term peak shaving supply of natural gas to power plants. However, each technique has its own inherent merits and limitations. For example, LRC requires the presence of a relatively thick layer competent rock at a shallow depth and large NGH production and gasification entails fabrication of a relatively large and uncommon facility. All factors being equal, reliability, safety, ease of operations, and costs would be the deciding factors for selection of the preferred system.

The logical next step for pursuing these issues is completion of a thorough site-specific feasibility study for a candidate power plant or operating scenario. In the first step, a study plan would be developed such that all relevant issues and problems would be addressed thoroughly and based on facts and figures as opposed to hypothetical and presumptive data. In general, these studies would include characterization of the needed peak hour gas in terms of volume, duration, and frequency based on historical data. Results from the need quantification would provide input for determination of facility capacity and withdrawal rate which is then used for calculation of required total cavern space, number of caverns, etc., or the NGH production/gasification units and peripheral equipment.

Parallel to these studies detailed geology of a number of candidate sites would be studied to investigate if the geological conditions are suitable for LRC. Similarly, water resources of the area would be studied to develop an appropriate water management scheme for development of a large size NGH facility. Regulatory and environmental issues and concerns relative to both LRC and NGH facilities would also be addressed in details.

Assuming that both LRC and NGH concept would prove to be feasible and admissible, first level estimates of capital investment and annual operating cost for each system would be developed. Results from the feasibility studies would be used in engineering and design work and would include realistic estimate of time for detailed engineering studies, field investigations (e.g. geophysical surveys), bidding and procurement processes, as well as construction and commissioning of each system. It is obvious that if early results from the suggested feasibility studies would lead to elimination of one of the two options, the detailed engineering and design work would be limited to the viable option. Accuracy and use of real-world data and information in the recommended feasibility studies would be of essence. In this manner, results from the work would provide the stakeholders with a deterministic decision making tool.

Summary of Technologies

The following table summarizes the alternative gas storage technologies discussed in this section.

TECNOLOGY	OPERATIONAL BENEFITS	ECONOMICS	TECHNOLOGY STATUS
Adsorbed Natural Gas	• Low pressure application • V/V ratio favorable • Potential alternative to CNG	• Economically prohibitive for large scale applications ($84M - $194M)	• Improvements in carbon material required • Viable for smaller application gas storage • Further development and field demonstrations recommended
Small-Scale LNG	• Density benefits • Mature technology • Known processes	• Viable at larger scale operation • Not proven economically viable at small scale (~$40M)	• Mature at larger scale operations • No additional research recommended at this time
Compressed Natural Gas	• Easily transportable • Flexible operations-scalable to larger applications • Known technology – simple process	• Not proven to be economically viable for large scale operations • Vessels costly	• Large footprint needed for vessel installation to achieve volumes necessary • Basic research complete and thorough • Pilot project recommended to determine operational and economic feasibility for larger applications
Cold Compressed Natural Gas	• Density benefits • Flexible process – CCNG/LNG • Pipeline compatible	• Potential for favorable economics but unproven at this point	• Requires additional demonstration of process technology • Pilot project recommended to determine operational and economic feasibility for larger applications • Considerable basic research completed
Natural Gas Hydrates	• Significant density benefits • Scalable technology • Stable operation	• Economics unproven at this point	• Further research required, no field applications or demonstrations to date • Improvements in dissociation capabilities

			required
Lined Rock Caverns	• Similar deliverability to salt caverns • Location relatively flexible	• Cost intensive ($100M+ for construction only) • Base gas required for pressurization	• Research required for identification of favorable locations in California

5.0 Regulatory/Policy Review

5.1. Project Approach

California is situated at the western end of the national natural gas pipeline system and relies on deliveries from other states and Canada for over 85% of its natural gas supply. Soon, deliveries from Mexico may be added to the mix. Among interested parties there is a clear consensus that natural gas storage located in California is playing an increasing role in meeting seasonal and peak day demand requirements. There is also broad agreement that new or expanded gas storage capacity and delivery enhancements are needed now and for the foreseeable future.

Storage improvements will aid California natural gas consumers by providing a near-market supply source. Such a supply source can enhance peak period deliverability, reduce gas price volatility, and compensate for weather-related production basin shortfalls, as well as transmission system disruptions.

This section examines the history of natural gas storage regulation in the U.S. in general and in California in particular. Regulation that could inhibit natural gas storage improvements, including those described in Section 4.0 of this report, are identified, and proposals are made to bring such regulation more into line with the policy of encouraging storage improvements. These proposals are intended to better match gas storage policy goals, while safeguards for gas consumers, the environment, and the general public are maintained. Issues related to market-based rate approval, and environmental and safety concerns are addressed in detail.

Federal and State Policies, Regulations and Decisions Review

A brief review was conducted of relevant Federal enabling legislation, policy statements, guidelines, and decisions. Specifically, this review addressed provisions of the Natural Gas Act of 1938, Federal Energy Regulatory Commission (FERC) Orders No. 436, 636, and 678, the FERC's Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, the National Environmental Policy Act (NEPA), the Federal Trade Commission's Horizontal Merger Guidelines, EPAct 2005, and FERC decisions on storage filings.

The impact of this Federal activity on the overall issue of enlarging and enhancing natural gas storage services in California was discussed. Specific FERC decisions on proposed gas storage projects (both new fields and enhancements) were reviewed for policy implications. Detailed case reviews can be found in the Section 5.0 Appendix.

Other options described in Section 4.0, such as onsite, onshore, liquefied natural gas (LNG) peak shaving storage, cold compressed natural gas, adsorbed natural gas, compressed natural gas, and gas hydrates, are also discussed. Relevant FERC and Department of Transportation regulations, including 49 CFR Part 193 -- LNG Facilities: Federal Safety Standards, and the National Fire Protection Association (NFPA) 59A – Standard for the Production, Handling and Storage of LNG, were also addressed.

California Public Utilities Commission (CPUC) regulatory results, including the Gas Accord and Wild Goose and Lodi independent storage facility decisions, California Energy Commission (CEC) policy recommendations and analysis relevant to gas storage, and state energy action plans, were reviewed. The LNG Interagency Permitting Working Group are also discussed.

CPUC and FERC approaches to determining whether market-based rates should be approved were reviewed in detail. Such approaches have recognized that relevant markets should be defined broadly to include good alternatives to storage, and that market-based rates may be approved despite evidence that relevant markets are highly concentrated. Resolution of environmental, safety and other issues at various regulatory levels was also discussed.

Environmental and Safety Concerns

Natural gas storage proposals typically undergo considerable environmental review. If underground storage or above ground alternative gas storage facilities are proposed, environmental considerations need to be taken into account and will be reviewed.

Alternative Gas Storage Regulatory Review

Potential regulatory impediments to alternative gas storage technologies identified in Section 4.0 were reviewed against a backdrop of existing Federal, state, regional, and local statutes, policies, regulations, and decisions.

Market-Based Rate Approval Process Review

This section will review the current regulatory approval process and provide options for removal or adjustment of potential barriers to storage expansion and enhancement (technologies from Section 4.0) using the precedent of FERC and CPUC decisions on storage proposals.

5.2. Project Outcomes

Like some commodities, natural gas can be stored almost indefinitely. The production, transport, and distribution of natural gas take time, effort and other resources and can be disrupted by natural and manmade causes. Near-market gas storage offers important advantages to consumers, since it can compensate for weather-related and other service disruption, moderate price volatility, and ensure supply when and where needed.

Natural gas storage can be economical for seasonal, monthly or daily peak shaving. A variety of gas storage options are available, including underground storage, "packing" gas under increased pressure into transmission lines, medium-sized LNG peak shaving plants, propane-air plants, above ground tanks or holders for atmospheric or compressed natural gas, and mined caverns. Three types of underground storage facilities are used in the U.S.: depleted reservoirs, aquifers, and salt caverns. However, only depleted reservoirs are used in California. Therefore, this task will focus on the depleted reservoir underground storage option. Other options recommended in Section 4.0 will also be examined.

The first use of underground storage in the U.S. occurred in 1916 in a depleted field south of Buffalo, New York. By 1930, there were nine storage facilities in six states. Growth of storage was slow during the first 25 years, reaching only eight billion cubic feet (Bcf) by 1940.

In California, to meet customer demand, the Southern California Gas Company (SoCal Gas) began storing gas in large holding tanks. In 1941, SoCal Gas introduced a new system, underground natural gas storage. El Paso Natural Gas Company began delivering interstate gas to California in 1947. By 1958, two California gas storage fields (Goleta and Montebello) were operational, with a capacity of 25 Bcf.[19]

Following World War II, natural gas demand soared. By 1962, some 258 storage areas with an ultimate capacity of 3.5 trillion cubic feet (Tcf) were operating or being developed in the U.S.[20]

Federal Policies, Legislation, Regulations, and Decisions Review

The principal owners of underground storage facilities in the U.S. are interstate natural gas pipeline companies, intrastate natural gas pipeline companies, gas local distribution companies (LDCs), and independent storage service providers. There are about 120 entities that own and operate nearly 400 underground storage facilities in the lower-48 states. These operators are often subsidiaries of, or partially owned by, an even smaller number of business entities. If a storage facility serves interstate commerce, it is subject to the jurisdiction of the FERC. Otherwise, it is state regulated.21

In 1985, FERC Order No. 436 established open access for transmission services, but it did not establish open access for gas storage. This became a concern of some large customers, who could not take advantage of seasonal pricing and demand for natural gas, even though these customers could purchase their own gas and pipeline capacity.

The FERC addressed these concerns in Order No. 636, issued in 1992. Order No. 636 mandated that: (1) storage services be unbundled, (2) customers be offered greater access to working gas capacity, and (3) customers be able to sell their storage capacity to others.

Under the Order No. 636 regime, interstate pipeline companies under FERC jurisdiction were, in fact, required to make available truly major portions of their working gas capacity on an "open access" basis. Specifically, this meant that the portion of gas storage field capacity and deliverability, above and beyond that needed to ensure system integrity and load balancing, would be made available to third parties on a nondiscriminatory basis. Ultimately, most underground storage capacity under FERC jurisdiction became subject to open access rules, with up to 90% of it available to gas transportation customers.

A major hindrance to underground storage service expansion in recent years has been difficulty obtaining market-based rate approvals. Storage services subject to FERC jurisdiction traditionally have been limited to rigid cost of service rates, unless they could pass special tests to qualify for more flexible market-based rates.

Over the years, the FERC has developed these tests for determining whether market-based storage rates should be approved. Importantly in this regard, the FERC issued Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines (Policy Statement)[22] in which it established a framework for analyzing market-based rate proposals for gas storage and other pipeline services.

---

[19] Parsons, James Natural Gas Supply of California, Land Economics, Vol. 34, No. 1 (Feb. 1958), pp. 19-36.

[20] IGT Home Study Course, Chapter XIV, 1964

[21] EIA, The Basics of Underground Gas Storage, August, 2004

[22] 74 FERC ¶ 61,076 (1996), reh'g and clarification denied, 75 FERC ¶ 61,024 (1996).

The Policy Statement's framework has two principal purposes: (1) to determine whether an applicant for market-based rates can withhold or restrict services, and, as a result, increase price by a significant amount for a significant period of time, and (2) to determine whether the applicant can discriminate unduly in price or terms and conditions. To find that an applicant cannot withhold or restrict services, significantly increase prices over an extended period, or unduly discriminate, the Commission must find either that there is a lack of market power because customers have good alternatives or that the applicant or the Commission can mitigate the market power. The Commission defines "market power" as the ability to profitably maintain prices above competitive levels for a significant period of time.

The Policy Statement's framework calls for analysis that defines relevant product and geographic markets, measures market shares and concentrations, and evaluates the ease of entry into relevant markets. Such analysis relies in part on calculating a so-called Herfindahl Hirschman Index (HHI) for use in determining market concentration. An HHI above 1800 is considered by the FERC to be cause for scrutiny as it indicates significant market concentration and that an applicant for market-based storage rates may have significant market power.

Demonstrating that market characteristics are compatible with market-based rate approval pursuant to the Policy Statement Framework has sometimes proven quite difficult, despite evidence that such rates were necessary to support needed expansion. This has been especially true in cases in which the storage providers in a given market territory were few. For instance, in 2002, Red Lake Storage requested[23] market-based rates for a proposed storage facility in Arizona, a state that at the time had no underground storage facilities within its borders. The FERC denied the rate request, ruling that the Red Lake facility, if built, would operate in a highly concentrated market in which it would have substantial market power.

In 2006, the FERC issued Order No. 678 amending FERC criteria for granting market-based rates for underground gas storage services. The Order No. 678 regulations were intended to make it easier to obtain market-based rates, thereby encouraging the development of new and expanded storage facilities, in two basic ways.

First, the FERC now will consider inclusion of a wide variety of "non-traditional" alternatives to proposed storage services in market share calculations. To the extent such alternatives are recognized, an applicant's market share is reduced, its potential to exercise market power diminished, and its chance of market-based rate approval increased. These alternatives include pipeline capacity, LNG through import terminals or peak shaving plants, and local gas production.

Second, the FERC implemented Section 312 of the Energy Policy Act (EPAct). This provision permits the FERC to approve market-based rates even if the proposer is unable to show lack of market power. In order to justify such a determination, however, the FERC must find that market-based rates are in the public interest and necessary to encourage needed storage capacity and that customers are adequately protected. The FERC applied this new criterion to both new storage fields and expansions of existing storage capacity.

[23] Red Lake Gas Storage, L.P., 102 FERC ¶ 61,077, reg'h denied, 103 FERC ¶ 61,277 (2003)

Shortly after issuing its Order No. 678 rehearing order, in November, 2006, the FERC put its new market-based rates standard into practice, and approved market-based rates for service from an aquifer storage field in Redfield, Iowa. [24]

California Policies, Legislation, Regulations, and Decisions Review

Prior to the late 1980's, California's regulated natural gas utilities provided virtually all gas services (including gas storage) to gas customers. Since then, the CPUC has gradually restructured the natural gas industry in order to give customers more options while assuring regulatory protections for those customers that wish to continue receiving utility-provided services.[25]

In 1993, the CPUC ruled that gas utilities no longer had storage service responsibility to noncore customers. The CPUC also ruled that the cost of storage service should be removed from noncore customer rates. That same year, CPUC also adopted specific storage reservation levels for core customers.

In 1997, the Wild Goose storage facility became the first independent storage provider in California. In its original and expansion decisions, the CPUC found[26], that while the California storage market was highly concentrated, market-based rates should be approved nonetheless.

On March 1, 1998, the Northern California natural gas market experienced a dramatic change with the restructuring of services on the Pacific Gas and Electric (PG&E) system under a broadly based settlement known as the “Gas Accord.” Many previously bundled PG&E services, including pipeline transmission and storage services within Northern California, were unbundled, providing more choice to marketers, shippers, and end-users. PG&E and the Gas Accord parties developed rules and guidelines applicable to PG&E’s system. As set forth in Gas Accord IV, which became effective in 2007, these rules and guidelines remain in effect today in modified form.[27]

In terms of clarifying state policy, the California Energy Action Plan (EAP) II[28] issued September 21, 2005 jointly by the CPUC and the CEC, indicated in its natural gas section that: California must also promote infrastructure enhancements, such as additional pipeline and storage capacity, and diversify supply sources to include LNG.

On July 25, 2005, Lodi Gas Storage (LGS) filed to become the second independent storage provider in California. In its March 2, 2006 decision[29] the CPUC indicated that the California storage market was highly concentrated. Nonetheless, CPUC granted market-based rate approval, but put restrictions on Lodi Storage and its parent company to the effect that LGS was

---

[24] Northern Natural Gas Company, Declaratory Order Authorizing Market-Based Rates, 117 FERC ¶ 61,191 (2006).

[25] http://www.cpuc.ca.gov/static/energy/gas/natgasandca.htm

[26] http://www.cpuc.ca.gov/published/Comment_decision/17053-03.htm

27 http://www.cpuc.ca.gov/Static/energy/gas/natgasandca.htm

28 http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

29 http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/54190.htm

prohibited from engaging in any storage or hub services transactions with its ultimate parents. It also referenced the EAP II and the need for additional natural gas storage facilities in northern California to enhance reliability and mitigate gas price volatility.

In a December 2006 decision[30], the PUC adopted a gas transmission framework for southern California, called the "firm access rights" (FAR) system, which is generally comparable to the "Gas Accord." SoCal Gas and San Diego Gas & Electric Company are expected to implement the firm access rights system in 2008. While the FAR agreement did not address storage directly, it covered transportation access to storage by allowing the holder of the FAR to be entitled to firm receipt access at a specific receipt point, including to a storage account.

The Wild Goose and Lodi decisions indicate that the CPUC is willing and able to go well beyond narrow market concentration analyses in determining whether to grant market-based rate approvals.

Environmental and Safety Considerations

Underground Storage

Natural gas storage proposals typically must undergo considerable environmental review. If underground storage is proposed, traditional natural gas exploration and production environmental considerations need to be taken into account, including those associated with wellbore road building, drilling muds and completion fluids, production water quality, and methane leakage. Since surface facilities are also involved, including in many cases compression stations with prime movers, both land use and air emission impacts need to be considered.

Compressor station fluids sometimes leak onto the ground, and PCBs have been found around some compressor stations. Air emissions from the compressor station engines, including NOx, CO, unburned hydrocarbons, and air toxics associated with prime movers need to be considered. In the near future, CO_2 emissions will also be a factor.

Compressor stations also need to be checked for methane leaks. And if compressor station prime movers are water-cooled, water use impacts must be evaluated. Noise and safety issues also may be raised. And because storage facilities must be connected to a gas pipeline system, environmental and safety concerns relevant to the gas pipeline may also be brought into play with regard to storage facilities.

With regard to the LGS storage decisions, the CPUC considered the following:

- The tradeoff between slightly lower on-site emissions and noise associated with electric-drive compressor engines versus the higher reliability of gas-driven engines;
- Additional air quality modeling for ozone precursors, like NOx and reactive organic gases, and the meeting of the San Joaquin Valley Unified Air Pollution Control District requirements;
- Eminent domain issues in light of SB 177 (regarding rights of public utilities to exercise public domain);

30 http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/62982.htm

- CPUC, State Lands Commission, and State Reclamation Board concerns as the pipeline proposed to connect the storage field to the gas transmission system: interference with agricultural activities, reduction in levee stability, and rate of subsidence;
- Concerns about natural gas releases to the atmosphere from compressor facilities, including emergency releases and those associated with normal depressurization for maintenance purposes;
- Consistency with local airport land use plans, which might involve interaction with the Federal Aviation Administration, and the relevant county Airport Land Use Commission and Board of Supervisors; and
- Concern about the safety of natural gas facilities and the potential for accidents, such as fire and explosion.

Ultimately, the CPUC found that the LGS project would have only minimal environmental and safety impacts. Nevertheless, as indicated above, the regulatory system used involved many local, state, regional, and federal agencies. Clearly, the regulatory process for dealing with environmental and safety issues associated with gas storage improvements is in need of coordination and simplification. Such coordination and simplification would take on even more importance in the event that storage improvement projects proliferate and demands on the regulatory process increase.

And in considering the Wild Goose expansion proposal, the CPUC stressed[31] the following for environmental review considerations:

- Conduct the review consistent with the California Environmental Quality Act (CEQA) and SEQA Guidelines and CPUC CEQA Rules 17.1;
- The U.S. DOT Office of Pipeline Safety (now the Pipeline and Hazardous Materials Administration) has authority over pipeline safety;
- Potential damage to scenic resources;
- Direct and indirect conversion of farmland to non-agricultural use (and the need for permits from the Butte County and Colusa County Agricultural Commissioners);*
- Potential conflict with existing designated land uses;*
- Potential to conflict with or obstruct the applicable air quality plan;
- Potential to violate any air quality standard (and involvement of the regional Air Quality Management District – AQMD);*
- Potential net increase of any criteria pollutant, including ozone precursors, in nonattainment under applicable Federal or State ambient air quality standard;*
- Potential to release objectionable odors;
- Potential to damage native vegetation or cause vegetation clearing;*
- Potential for damage to riparian (river or stream bed) habits;*
- Potential for loss and conversion of wetlands or conversion of wetlands;*
- Potential for effects on fish or other aquatic life, wildlife, and nesting birds;*

31 http://www.cpuc.ca.gov/Environment/info/mha/wild_goose/index.html

- Potential for introduction of noxious weeds;*
- Potential for damage to recognized historic places or unidentified cultural resources;*
- Potential for effects from faulting, uplift, or seismic ground shaking;*
- Potential to expose people to liquefaction or landslide effects;*
- Potential for soil erosion or subsidence;
- Potential for effects on extraction of mineral, natural gas, or gravel resources;
- Potential for accidental release of hazardous substances or emissions;*
- Potential for risks of fire or explosion;
- Potential to interfere with an emergency response or evacuation plan;*
- Potential to substantially degrade surface or ground water quality or deplete ground water supply, or cause flooding;*
- Potential to physically divide an existing community;
- Potential to conflict with land use plans;
- Potential to conflict with conservation plans;
- Potential for temporary or permanent increase in ambient noise levels; and
- Potential for substantial increases in: population growth, public resources use, emergency provider interference, traffic during construction*, wastewater treatment, solid waste disposal, or a new source of light for highways.

* Topics shown with mitigation measures

Letters were received from the following agencies:

- Federal: U.S. Fish and Wildlife Service
- State: California Division of Oil, Gas, and Geothermal Resources and the Department of Water Resources, State Reclamation Board
- Regional and Local: Butte County AQMD

The CPUC approved the expansion proposal overall and either accepted the Company's proposals as to specific issues or required mitigation measures. The list of issues set forth above is onerous, and the effort and resources needed to deal effectively with such a set of issues could very well discourage storage improvement proposals. Nonetheless, the speed with which the CPUC proceeded in examining and deciding these issues, and the effectiveness of their coordination with other local, regional, State and Federal agencies, was commendable.

Onsite LNG Storage

The process of liquefaction, storage, and regasification of natural gas requires refrigeration and condensation for atmospheric storage at approximately -260°F. As a liquid at this pressure, natural gas requires only about 1/600th of its gaseous atmospheric pressure volume. When gas is required for peak shaving, liquid is withdrawn from storage and revaporized by the addition of thermal energy.[32]

[32] IGT Gas Distribution Home Study Course, p. 287

Hope Natural Gas pioneered the use of liquefaction for peak shaving in 1940 at a pilot plant in Cornwall, West Virginia. The following year East Ohio Gas built a full-scale LNG peak shaving plant in Cleveland. After three years of successful operation, the plant was involved in a disastrous fire and later dismantled. Safety recommendations that were made subsequent to the Cleveland fire, especially one for very high land clearance distances, and the relatively high cost of metallurgically sound tankage slowed further development until the 1950's. The U.S. Bureau of Mines in 1962 reported[33] the results of a study of LNG fire and explosion hazards, and concluded that with the proper containment, particularly diking, LNG could be stored safely in much the same manner as gasoline.

During the 1950's and 1960's, extensive and large-scale application of liquefaction processes to other low-temperature and cryogenic gases had refined the engineering and metallurgical knowledge in the field. In 1956, operation began for an experimental liquefaction plant at Lake Charles, Louisiana, to experiment with marine transportation of LNG. In 1963, Transcontinental Gas Pipeline received permission[34] from the Federal Power Commission (FPC, predecessor to the FERC) to build a large plant near Carlstadt, New Jersey and to offer peak shaving service for its customers at special storage rates.

According to a recent Energy Information Administration (EIA) study[35] there are 113 active LNG facilities in the U.S., including import terminals, peak shaving plants, and plants for niche markets such as LNG for use as a vehicle fuel. The vast majority of these sites serve as peak shaving facilities. About 96 of these facilities are dedicated solely to meeting the storage needs of gas LDC's and pipelines. Of these, 57 have the capability to liquefy and to re-gasify natural gas, 39 are "satellite" facilities where the LNG must be transported in (by truck or train) and have only re-gasification capability. About 83 are owned by gas LDC's, and 13 by interstate pipelines. Virtually all of the facilities are connected to the gas pipeline grid or LDC gas distribution system.

According to the EIA study, LNG facilities throughout the world generally have had an excellent safety record in over 35 years of operations. However, as with many industrial complexes, environmental, safety, and security concerns remain paramount.

The FERC has the lead responsibility for authorizing the construction and siting of onshore LNG facilities under Section 3 of the Natural Gas Act. It performs environmental and safety reviews of LNG plants and prepares environmental impact statements, as required by the National Environmental Policy Act (NEPA). Public comments are solicited. The FERC also authorizes the construction and operation of interstate pipelines that are associated with LNG facilities, under Section 7 of the Natural Gas Act.

The U.S. Department of Transportation, Office of Pipeline Safety (U.S. DOT OPS), Research and Special Programs Administration (RSPA) has authority over safety regulations and standards

[33] Zabetakis, and Burgess, "Fire and Explosion Hazards Associated with LNG, U.S. Bureau of Mines R.I. 6099, 1962

[34] FPC Docket # CP63-228, filed Feb. 18, 1963.

[35] Energy Information Administration, U.S. LNG Markets and Uses: June 2004 Update

for the transportation and storage of LNG in interstate commerce or foreign commerce under pipeline safety laws (49 USC Chapter 601).

LNG operations that are incorporated into local distribution systems are regulated by state public utility commissions in most respects, just as are other operations of such systems. Thus, state public utility commissions regulate the economic aspects of both the construction of new LNG facilities and the operations of existing plants. The U.S. DOT OPS, however, regulates the safety of the LNG operations.

In terms of California experience with LNG, in addition to a 10,000-gallon per day experimental technology demonstration plant located in Sacramento and owned by PG&E, there are eight other liquefaction plants located in California. Governmental entities or large-scale commercial vehicle users own these facilities. For example, the City of Santa Monica owns the liquefaction facilities used to produce LNG for its fleet of LNG-fueled transit buses. Similarly, Orange County owns the Orange County Transit Authority. In certain areas of the state, third parties can acquire liquefaction services for their own supplies of natural gas. For instance, PG&E sells liquefaction service for customer-owned natural gas, pursuant to a tariff approved by the CPUC. As of 2003, there were 28 privately owned and publicly owned LNG vehicle fueling stations across the state.

To date, no LNG import terminals have been constructed in California or in its adjacent coastal waters.

However, LNG is still used in Santa Monica and Orange County, as an alternative fuel for transit buses; in San Diego, Sacramento, and Riverside County by GTI Rubbish, Norcal Waste Management, and Waste Management, Inc. to fuel trash haulers; and to fuel heavy duty trucks, including those used by Vons, Raleys/Bel Air, and Sysco Food Services.

A portion of this vehicle fuel comes from LNG liquefaction facilities located in the state, including the 10,000-gallon per day facility located in Sacramento, and the remainder is trucked in from plants located in Wyoming, the Pacific Northwest, and Topock, Arizona. Some LNG tanker trucks, which typically carry 10,000 to 12,000 gallons of LNG, are equipped with vaporizers that allow the LNG to be trucked to a site that requires temporary, supplemental natural gas for immediate use. The largest single source of LNG used in California is a plant owned by an affiliate of El Paso Natural Gas Company. This plant, located near Topock, Arizona, supplies California with approximately 29,000 gallons of LNG per day. [36]

There are two LNG plants that supply peak shaving energy to California. Nearly all the LNG currently delivered to California is produced at an 86,000-gpd maximum capacity liquefaction plant in Topock, Arizona, which is adjacent to the California border. El Paso Field Services owns the liquefier at the Topock, Arizona facility, but Applied LNG Technologies USA (ALT), owns the storage and truck-loading facilities. This plant delivers LNG to industrial, municipal (i.e., gas LDC's), and Arizona and California transportation customers.

The second LNG plant is physically located in California, but it is not a typical LNG peak shaving plant. The Quadren Cryogenics plant liquefies high-nitrogen gas from the Robbins

[36] http://www.eob.ca.gov/attachments/081004NatGasReport.pdf

field, northwest of Sacramento, and produces ultra-high-purity methane for the specialty gas market, including limited amounts for transportation.

This analysis does not include the Prometheus Plant, as its size and source of methane render it unique. In early 2007 the world's first plant producing LNG from landfill gas began operations in Orange County, California. The plant, owned by Prometheus Energy Co., has a nameplate capacity of 5000 gal/day. The LNG will be used as an alternative fuel in the public transit system in Orange County.

PG&E has recently unveiled[37] an innovative approach that is expected to revolutionize LNG production and increase volume. PG&E has developed an on-site LNG liquefier in conjunction with Idaho National Engineering and Environmental Laboratory (INEEL) and others estimated to cost $450,000, as compared to conventional LNG plants that cost approximately $10 million. Another attraction of this new liquefier, which is expected to generate 10,000 gallons of LNG daily, is that it will occupy only 240 square feet, instead of the five to six acres needed for a conventional plant.

The PG&E LNG liquefier draws natural gas from an existing pipeline and is designed to be located at pressure letdown stations. A pressure letdown station exists where high-pressure transmission gas lines (350-500 psi) branch to much lower pressure (50-60 psi) local distribution pipe networks. The gas pressure differential from high-pressure to low-pressure provides energy to drive a turbo-expander which in turn creates the pressure and temperature differences needed to liquefy natural gas to LNG. One on-site PG&E LNG liquefier has been installed in Sacramento.

Following the success of the Sacramento facility, the California-based Southwest Transportation Agency (STA), Hanover Compression LP, and the San Joaquin Valley Air Pollution Control District partnered with the INEEL to develop and demonstrate a liquid and compressed natural gas fueling station in Caruthers, California. Since April 2005, one-third of Fresno's school buses have been filling up at the Caruthers, California station.[38]

There are four other out-of-state natural gas liquefaction facilities that have provided limited volumes of LNG to California. These include the ExxonMobil Corporation nitrogen rejection unit near Shute Creek, Wyoming; the BP p.l.c. nitrogen rejection unit near Painter, Wyoming; the Pioneer Natural Resources USA nitrogen rejection unit near Santana, Kansas; and a Williams Field Services NGL plant near Durango, Colorado. [39]

The principal federal safety regulations governing LNG peak shaving facilities are 49 CFR Part 193 -- LNG Facilities: Federal Safety Standards and the National Fire Protection Association (NFPA) 59A – Standard for the Production, Handling and Storage of LNG.

The FERC approves LNG inland facility siting pursuant to regulations contained in 18 CFR Part 153. These regulations detail the process and requirements under Section 3 of the NGA, which

[37] http://yarts.com/docs/2003/Alt%20Fuel%20Study.pdf

[38] http://www.inl.gov/featurestories/2007-05-31.shtml

[39] http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10836742

apply to LNG import applications. These requirements include detailed site engineering and design information, evidence that a facility will safely receive or deliver LNG, and delineation of a facility's proposed location. Additional data are required if an LNG facility will be in an area with ecological risk. The regulations also require LNG facility builders to notify landowners.

The U.S. Department of Transportation (DOT) has overseen LNG facilities under authority of several Acts, including the Pipeline Safety Act of 1994 and the Pipeline Safety Improvement Act of 2002. The latter statute requires the Secretary of Transportation to consider geophysical risks, population proximity, emergency services adequacy, operator qualifications, and security measures when promulgating LNG facility rules.

DOT sets minimum standards for all stages of LNG facilities – siting, design, construction, and operation as set forth in 49 CFR Part 193. DOT's Office of Pipeline Safety oversees the safety and security of LNG facilities.

The National Fire Protection Association (NFPA) also has numerous standards for LNG, namely NFPA 59A, mentioned above. Many of these standards are incorporated into federal regulations. NFPA 59A requires thermal exclusion zones and flammable vapor-gas dispersion zones around LNG terminals. While it establishes these minimal siting requirements, DOT does not itself approve or deny specific siting proposals, with such authority instead vested in the FERC. The DOT regulations also adopt many of NFPA's design and construction guidelines including requirements for LNG facilities to withstand fire, wind, hydraulic forces, and erosion from LNG spills. Other provisions address operations, maintenance, employee qualification, and security.

As part of the Aviation and Transportation Security Act of 2001, relevant security authorities were transferred from DOT to the Transportation Security Administration.

Localities have many additional requirements for facilities in their jurisdictions. Some of these requirements apply only to LNG facilities, while others apply to facilities with certain characteristics, whether associated with LNG or not. Many states are certified by the DOT, and have adopted and can enforce DOT safety regulations.

Under the National Environmental Policy Act (NEPA), FERC must prepare an environmental impact statement as an important focus of its LNG terminal siting application review. Such FERC reviews consider the socioeconomic impact of the LNG facility; site geophysics; seismic risk safeguards; air and noise quality impacts; potential accidents or malfunction impacts on public safety issues; and facility compliance with safety and reliability standards. Public safety risks associated with potential accidents are also included in the evaluation. Owners and operators of LNG facilities also conduct risk assessments as part of their siting and design evaluations. Other public concerns are also addressed in the NEPA review process.

In terms of California policy, the CEC's integrated policy report[40] stated: "Looking forward, California must actively encourage infrastructure enhancements such as additional pipeline capacity, incentives for increased operation and use of in-state storage, in-state productive capacity, and nontraditional supply sources such as liquefied natural gas." Also, the CEC

40 http://www.energy.ca.gov/reports/100-03-019F.PDF, December 2003

recommended that the State: "Encourage the construction of liquefied natural gas facilities and infrastructure and coordinate permit reviews with all entities to facilitate their development on the West Coast."

To deal with LNG issues more effectively at the state government level, the Energy Commission recently sponsored the formation of the LNG Interagency Permitting Working Group. The working group meets on a regular basis and includes the California Air Resource Board, the California Coastal Commission, the California Coastal Conservancy, the California Energy Commission, the California Public Utilities Commission, the Department of Conservation, the Department of Fish and Game (DFG), the Department of General Services, the DFG's Office of Spill Prevention and Response, the Electricity Oversight Board, the Governor's Office of Emergency Services (OES), the OES's Office of Homeland Security, the Office of Planning and Research, the San Francisco Bay Conservation and Development Commission, and the State Lands Commission. These agencies will potentially be involved with permitting LNG facilities in California. The goal of the working group is to ensure that any LNG development is consistent with state energy policy that balances environmental protection, public safety, and local community concerns.

Onsite Compressed Natural Gas (CNG) Storage

Since the storage tanks for CNG can reach pressures of 3,600 psi or higher, safety considerations are critical in the design and permitting of these facilities. The FERC does not generally regulate CNG storage, since most of it is not transported across state lines. Therefore, this report will concern itself with California Regulations.

Most CNG storage tanks are covered under the California Code of Regulations, Title 8, Section 541, Article 7, [41] and Title 8, Section 531. [42] None of these regulations constitute an impediment to CNG above ground tank-based options.

Onsite Adsorbed Natural Gas (ANG) Storage

ANG storage technology has achieved a storage density of 180 volumes/volume (v/v), the target set by DOE. This means that ANG storage systems are feasible even at 500 psi, versus over 3,600 psi for CNG systems. This lowers the hazard and safety risk associated with ANG systems compared to CNG systems. Given this much lower pressure, steel storage tanks used for ANG do not need to be the same as costly high-pressure tanks associated with CNG. Though regulations similar to those that apply to CNG tanks currently apply to ANG tanks, the lower pressure associated with ANG may make the siting of ANG facilities easier than comparable CNG facilities.

However, one potential issue is the use of advanced ANG materials like single-walled carbon nanotubes that have potential for adverse health impacts.[43] Appropriate manufacturing, handling, and disposal methods for the adsorbed materials must be considered.

41 http://www.dir.ca.gov/Title8/541.html

42 http://www.dir.ca.gov/title8/531.html

43 http://toxsci.oxfordjournals.org/cgi/reprint/kfh041v1.pdf

Lined Rock Caverns (LRC)

LRC is mentioned for use with both gas hydrate and cold compressed natural gas storage options, and it is also suitable for compressed natural gas applications. The specific impacts associated with LRC themselves are dealt with in this section.

Environmental impacts associated with LRC can occur both during construction and during operation of the facility.[44] Construction of the LRC facility can take up to four years. Conventional "drill and blast" techniques will probably be used for the tunnels and caverns. Ground vibrations will occur, but probably will be contained within the plant perimeter. The disposal of the rock mass removed will be a major consideration. For a four-cavern facility, the rock aggregate could approach 21 million cubic feet. Some of the rock mass can be used for site preparation and concrete production. The remaining rock aggregate can be sold in the marketplace.

Major environmental effects can occur from the rock excavation work and pipeline construction. Since pipeline construction environmental impact is well understood, this section will cover only the rock excavation impacts. Landscape, vegetation, and soil may be impacted. Animals may be disturbed during construction. There may be a lowering of the water table due to the excavation. Since the LRC will be designed to minimize water ingress, the water table changes should exist for only a short time. Any water that continues to leak into the tunnel and caverns will need to be pumped out and cleaned. Some of the water can be used on site, some disposed of, and some reinjected into the ground. Dust may arise due to construction traffic and the construction itself.

Once the LRC plant is in operation, there will be noise from the compressor station, which may disturb animals and nearby recreation activities. As discussed above, minimal groundwater impact is anticipated. Air emissions from the compressor station will need to be dealt with. Natural gas leakage, after construction, is expected to be minimal.

The following table[45] exemplifies the federal and state regulatory processes and organizations that a LRC storage proposal needs to go through. As previously, 18 CFR Parts 157 and 184 apply for storage certificates of service and environmental permitting related to land and water use and air quality, with due consideration for vegetation, wildlife, cultural resources, recreational use, soil use, noise and air quality, and of course, safety and reliability. FERC would only be involved if interstate transport of the gas was anticipated.

The particular state (Massachusetts) exemplified in the study may have different state agency names then California, but the state requirements are very similar. The state environmental authority, local air quality management district, water pollution control districts, regional industrial waste management agency, watershed and wetlands management organizations, hazardous materials handling organizations, would all need to be contacts and approvals or waivers sought. The one difference from Massachusetts would be the subsidence and seismic considerations and permits necessary in California.

---

44 http://www.netl.doe.gov/technologies/oil-gas/publications/Storage/34348_final.pdf

45 http://www.netl.doe.gov/technologies/oil-gas/publications/Storage/34348_final.pdf

These regulations are not expected to be major impediments to construction and operation of the LRC facility and the fact that much of the facility will be below ground may make it more acceptable to the general public. One recommendation to speed up the process yet ensure a thorough review is to appoint a lead California agency to receive all permits, and then that lead agency would distribute the needed information to the other agencies.

Table 36 Federal and State Regulations That are or may be Applicable to the LRC Technology in Massachusetts (Section 1 of 5)

Type	Citation	Agency	Description and Requirements	Relevance to LRC Tech.
	18 CFR Part 157 & 284[(a)]	FERC	**7(C) Certificates of the Natural Gas Act** Certificates are required to demonstrate or receive: • public convenience and necessity • provision of storage and transportation services • approval of market-based rates • confidential treatment Typical permit application requirements include the following descriptions or evaluations: • project • water use & quality • vegetation & wildlife • cultural resources • socioeconomics • geology • soils • land use, recreation, and aesthetics • air & noise quality • alternative • reliability & safety • engineering & design	Yes
Regula tory Affairs	301 CMR 11.00[(b)]	MEPA (State)	**Massachusetts Environmental Policy Act** Environmental Notification Form (ENF) to be filed with the Massachusetts Environmental Policy Act(MEPA) Office. Agency and public comment period follow. Environmental Impact Report (EIR) may be required. Agency and public comment periods follow with a statement issued at the end of the process.	 Likely Unlikely
Air Quality Control	310 CMR 6.00, 7.00, & 8.00	MADEP (State)	**Air Permits** Air Plan approval required for construction of certain projects: • fuel utilization facility with energy input above certain threshold limits • construction in non attainment areas • certain boilers, stationary engines, &	

			emergency generators Relevant Permits: <u>BWP AQ 02</u> (Nonmajor comprehensive approval) <u>BWP AQ 03</u> (Major comprehensive approval)	Likely Unlikely

Federal and State Regulations That are or may be Applicable to the LRC Technology in Massachusetts (Section 2 of 5)

Type	Citation	Agency	Description and Requirements	Relevance to LRC Tech.
Industrial Wastewater Management	314 CMR 314 CMR 3,00, 4.00 & 12.00 314 CMR 7.00 & 12.00 314 CMR 5.00 & 6.00 314 CMR 12.00	MADEP (State)	**<u>NPDES Permits - Industrial Wastewater</u>** <u>BWP IW 18</u> Permit required for industrial wastewater discharge to surface waters (no threshold limits based on discharge volume or rate). <u>BWP IW 12</u> (Type I Facility) Permit and Plan approval required for industrial wastewater discharge to MA sewer system. <u>BWP IW 24</u> (Type I Facility) - plan approval only. <u>BWP IW 05</u> (Type I Facility) Permit to discharge industrial wastewater to groundwater. Permits required to store industrial wastewater on site in a holding tank with disposal via POTW. No thresholds based on amount of discharge. <u>BWP IW 01</u> (Permit to construct & install a non-hazardous holding tank). <u>BWP IW 28</u> (Permit to convert an existing tank to a nonhazardous holding tank).	Possible Possible Possible Unlikely Unlikely Unlikely
Water Pollution Control	310 CMR 15.00 (Title 5 Regulations) 314 CMR 7.00 & 12.00	Municipal Board of Health MADEP (State	**<u>Sanitary Sewage Systems</u>** Disposal Works Construction Permit is required from the local municipal Board of Health for septic systems <10,000 gpd. State permits are required for sanitary sewage disposal systems >10,000 gpd. BWP WP 01 Title 5 Plan Approval BWP WP 02 Title 5 Variance BWP WP 03 Approval of miscellaneous sewage treatment systems BWP WP 04 Permit to pump sewage prior to	Possible Unlikely

			entrance to septic tank BWP WP 10 Permit for discharge to groundwater (includes noncontact cooling water >2,000 gpd, -stormwater, construction dewatering, & other discharges with certain limited treatment	

Federal and State Regulations That are or may be Applicable to the LRC Technology in Massachusetts (Section 3 of 5)

Type	Citation	Agency	Description and Requirements	Relevance to LRC Tech.
Water Pollution Control	314 CMR 7.00 & 12.00	MADEP (State)	**<u>Sewer Connection to Public System</u>** Permits are required for the following public sewer connections. <u>BRP WP 14</u> Sewer extension £2,500 feet & with flows <50,000 gpd or connected to a pump station.	Possible
	314 CMR 7.00 & 12.00	MADEP (State)	<u>BRP WP 55</u> Permit for sewer extension or industrial wastewater connection (not covered under Industrial Wastewater Management Program) for flows ≥ 15,000 gpd.	Unlikely
			<u>Industrial Wastewater Holding Tank</u> <u>BRP WP 56</u> Permit for industrial wastewater holding tank for a facility without a safer alternative.	Unlikely
Watershed Management	40 CFR 122-125 31 CMR 3.00 & 4.00	USEPA & MADEP (State)	**<u>NPDES Permits - Surface Water Discharge</u>** NOTE: Massachusetts is not a delegated state under the Clean Water Act; therefore, a USEPA General Permit is required for Stormwater (Notice of Intent), construction site dewatering, noncontact cooling water, & minor nonprocess wastewater. An approved storm water management plan is required. MADEP review will not being until after a draft permit has been received from USEPA. The permit program is administered jointly with the USEPA.	Unlikely
			<u>BWP WM 06</u> (Type I Surface Water Discharge).	Yes
			<u>BWP WM 08</u> (EPA General Permit (NOI), Stormwater).	Yes
			<u>BWP WM 09</u> (Approval of Stormwater Management Plan).	Yes
			<u>BWP WM 10</u> (EPA General Permit, Construction Site Dewatering).	Unlikely
			<u>BWP WM 11</u> (EPA General Permit, Noncontact	Possible

			Cooling Water). BWP WM 13 (EPA General Permit, Minor Nonprocess Wastewater).	
Watershed Manageme nt	310 CMR 4.00 & 36.00	MADEP (State	**Surface Water & Groundwater Withdrawal** BRP WM 03 Permit required for surface water or groundwater withdrawal from river basins at a rate >100,000 gpd or >9 million gal/3 mos.	Unlikely

Federal and State Regulations That are or may be Applicable to the LRC Technology in Massachusetts (Section 4 of 5)

Type	Citation	Agency	Description and Requirements	Relevance to LRC Tech.
Water Supply	310 CMR 27.00	MADEP (State)	**Underground Injection Control** BRP WS 06 Permit required for Class V well (underground injection). NOTE: A recharge well(s) used to replenish water in an aquifer is classified as Class V.	Possible
Wetlands & Waterways	310 CMR 9.00 & 10.00	MADEP (State)	**401 Water Quality Certification** Required under the Federal Clean Water Act for certain activities in wetlands and waters. Massachusetts has the authority to review projects that must obtain federal licenses or permits that result in discharges to state waters. This applies to dredging, disposal of dredged material, & placement of fill in vegetated wetlands or waters subject to federal jurisdiction. An optional Determination of Applicability (BRP WW 04) for projects can be made by the Waterways Regulations Program. Relevant license, permit, or certificate of compliance required for wetlands or waterways work include:	Possible Unlikely

			BRP WW 01 Waterways license - required for projects involving the placement of structures & fill in nontidal rivers & streams and other categories.	Possible
			Waterways permit - required for projects not involving fill or placement of structures in waterways (such as dredging).	Unlikely
			BRP WW 11 Project certification required for minor fill or excavation (loss up to 5,000 ft2 of bordering & isolated wetland).	Unlikely
			BRP WW 08 Project certification required for minor dredging (between 100 yd3 and 5,000 yd3).	Possible
			BRP WW 05 Certificate of Compliance required within 60 days of completion of the project.	Likely
		USACOE	**Section 404 Permit (Federal)** Needed for a proposed activity that involves filling and construction in any waterway or wetland.	Unlikely
		USACOE	**Section 10 Permit (Federal)** Needed for dredging, filling, or construction & repair of structures in navigable waters.	

Federal and State Regulations That are or may be Applicable to the LRC Technology in Massachusetts (Section 5 of 5).

Type	Citation	Agency	Description and Requirements	Relevance to LRC Tech.
Wetlands & Waterways	310 CMR 10.00	Local Conservation Commission	**Wetlands Protection** Wetlands protection is administered by local conservation commissions. A Notice of Intent (NOI) and permit (Order of Conditions) is required from the local conservation commission for removing, dredging, filling, or other altering of a wetland.	Possible
Hazardous Materials	 40 CFR 262 310 CMR 30.00	 USEPA MADEP (State)	**Hazardous Waste Generators** Registration required for hazardous waste generators (LQG, SQG, & VSQG). • EPA ID Number required for LQG & SQG (except waste oil)) • MADEP registration required for VSQG & waste oil SQG. NOTE: Waste oil is classified as hazardous in MA. Hazardous materials recycling permit required for >27 gal. hazardous waste per month.	Possible Unlikely
Toxics Use Reporting	310 CMR 40.00, 41.00, & 50.00	MADEP (State)	Regulations which apply to facilities that use at least 10,000 lbs. of any chemical listed on EPA's Toxic Release Inventory (Section 313 - Emergency Planning and Right-to-Know and CERCLA).	Unlikely
Solid Waste Management	310 CMR 16.00 & 19.00	MADEP (State)	**Solid Waste Management Facilities** NOTE: A comprehensive site assessment is required for a solid waste management facility permit. Permits (or other) are required for the following categories: BWP SW 17 Determination of Need, Small Operation Site Assignment. BWP SW 27 Permit for new landfill between 25 & 250 acre feet (volume). BWP SW 28 Permit for new landfill <25 acre feet (volume)	Unlikely

			BWP SW 10 Permit to receive authorization to operate a new landfill. BWP SW 01 Permit to establish a new solid waste facility.	

Gas Hydrate Storage

As indicted in Section 4.0, the use of natural gas hydrates as a peak shaver in storage operations would entail creating the hydrate at or near a candidate high consumption point of use, or at a storage sites, in off-peak periods and gasification during the high demand times.

"Naturally occurring" natural gas hydrates[46] occur worldwide in Polar Regions normally associated with onshore and offshore permafrost, and in sediment of outer continental and insular margins. Because gas hydrates are metastable, changes of pressure and temperature affect their stability. Destabilized gas hydrates may affect climate through the release of methane, a "greenhouse" gas, which may enhance global warming and be a factor in global climate change. ***However, the use of gas hydrates as a storage option will not adversely impact global warming.*** The gas hydrates used for storage will be contained in LRC's, containment vessels, or pipelines, so that, even if destabilized by changes in temperature and/or pressure, the freed methane will not escape into the atmosphere.

A more pertinent issue is the toxicity of surfactants used to influence hydrate formation. Sodium Dodecyl Sulfate (SDS) is mentioned[47] as a surfactant that promotes faster gas hydrate formation rate when using gas hydrates as a storage medium. There have been a number of studies of the toxicology of SDS. One report[48] indicated that, "Based on an initial assessment of the effect and exposure data provided in the SIDS dossier, the chemical can be considered to present a low potential for risk to man and the environment."

A second report[49], however, indicated that for SDS there was a correlation between toxicity and lens optical function in bovines (ox or cow related). The results further showed that a recovery of the lens metabolic function was necessary for a recovery of the lens optical properties.

A medical safety data[50] sheet indicated that SDS was "harmful if swallowed or inhaled, causes irritation to skin, eyes, and respiratory tracts, may cause allergic skin reaction or respiratory reaction", and that SDS was a flammable solid. A NOAA document[51] indicated that, while SDS

[46] http://www.agu.org/pubs/crossref/1993/93RG00268.shtml

[47] http://204.154.137.14/technologies/oil-gas/publications/Hydrates/reports/MHyd_41297Final.PDF, p.1

[48] SIDS INITIAL ASSESSMENT PROFILE on Sodium dodecyl sulfate (SDS).htm

[49] http://toxsci.oxfordjournals.org/cgi/content/abstract/73/1/98

[50] http://www.jtbaker.com/msds/englishhtml/s3670.htm

[51] http://www.sefsc.noaa.gov/HTMLdocs/SodiumDodecylSulfate.htm

was not carcinogenic, "the solution may cause acute or chronic irritation of skin, eyes, and mucous membranes" and that the ingredients were "hazardous."

Further toxological study is warranted before SDS can be given the "clean bill of health" implied by the first report. If there is a toxological issue with SDS, then appropriate materials handling and disposal precautions must be taken with this compound in order to ensure safety to humans and wildlife.

Cold Compressed Natural Gas (CCNG)

CCNG, because it is both a cryogenic substance (stored at -150°F) and requires high-pressure (stored at 700 – 1600 p.s.i.)[52] containment, CCNG must meet the regulatory challenges inherent in containing cryogenic liquids or gases and in containing high-pressure gases. So while it has technical advantages over both LNG and CNG, it suffers from having to meet many of the regulatory challenges pertaining to both those technologies. As this is a relatively untried technology, regulations governing its use have not been made specific to CCNG, and so are somewhat uncertain. What is certain is that good quality containment vessels and pipelines will be required, of such substances as nickel-steel, and that adequate insulation materials must also be used.

As with LNG, issues of containment, safety, fire prevention, thermal exclusion and vapor dispersion zones, and environmental impact must all be dealt with. As indicated previously, most pressurized (CNG-like) storage tanks are covered under the California Code of Regulations, Title 8, Section 541, Article 7, [53] and Title 8, Section 531. [54] So the CCNG systems will need to navigate through both sets of requirements. It would help to make the regulatory process for CCNG more certain if specific guidelines for CCNG type systems were delineated separate from LNG and CNG type systems.

Alternative Gas Storage Regulatory Review

It can be expected that all of the underground storage options recommended in Section 4.0 will require CPUC review. And while the CPUC has looked beyond HHI's above 1800 before and approved market-based rates despite them, it is clearly better that a strong case be made that an HHI of no more than 1800 is applicable.

It is important to note that if the expanded definition of the storage market from Table 41 is used, LGS could increase its deliverability level substantially above the current level of 550 MMcf/d before an HHI level of 1800 is reached. In fact, it is not until LGS reaches a level of 3100 MMcf/d that the index increases at all, and it reaches 1800 only when LGS reaches 6710 MMcf/d. Clearly, to the extent that Table 41's definition of the storage market prevails, the HHI threshold presents no practical near-term limit to expansion and enhancement of storage services rendered by the existing independent storage providers and new entrants of similar size.

---

[52] See Chapter 4 of this report, Table 11

53 http://www.dir.ca.gov/Title8/541.html

54 http://www.dir.ca.gov/title8/531.html

Expansion of existing capacity or deliverability could also come from an existing major storage service provider such as SoCal Gas. In fact, the Table 41 approach would allow SoCal Gas to increase its deliverability from the current level of 3,175 MMcf/d to 4700 MMcf/d before the HHI reaches the 1800 threshold. This would allow a 48% expansion in SoCal Gas's deliverability without signaling a market concentration level that could warrants regulatory scrutiny.

Clearly, reliance on the Table 41 approach would ease the entry of new players into the California storage market, as well as encourage existing providers to expand their services.

As to Section 4.0's onsite LNG storage option, facilities already approved in California may not serve as strong precedent for approval of new LNG peak shaving plants. Although some regional and state environmental groups has been very positive toward LNG-for-vehicles facilities, LNG peak shaving plants may be seen in a different light.

Despite U.S. DOT OPS RPSA, CPUC, and regional AQMD reviews, the environmental, safety and other permits required by the relevant local, regional, State and possibly Federal agencies discussed above call into question whether all approvals necessary for an LNG peak shaving facility could be forthcoming in a reasonable period of time.

Market-Based Rate Approval Process Review

Gas Storage Methodologies

As indicated above, both the FERC and the CPUC have recognized that market-based rates should be approved under certain circumstances to encourage gas storage improvements. To aid in making such decisions, these agencies have developed tests for use in determining whether market-based storage rate authority should be granted. These tests call for analyses that define product and geographic markets, measure market shares and concentrations, gauge ease of entry into such markets, and evaluate other relevant factors.

Such tests have typically relied in part on calculating one or more Herfindahl Hirschman Index (HHI), which is a sum of the squares of relevant market shares, for use in determining market concentration. An HHI above 1800 is considered to be cause for scrutiny as it indicates significant market concentration and that a market-based storage rate applicant <u>may</u> have significant market power. An HHI below 1800, on the other hand, indicates that no further market power analysis is required.

The regulations promulgated by FERC Order No. 678 encourage the development of new and expanded storage facilities by making it considerably easier for applicants to qualify for market-based rates. This is accomplished in two basic ways. First, the FERC now will consider inclusion of "non-traditional" alternatives to storage services in market analyses, potentially lowering market shares and HHI's. Second, the FERC implemented Section 312 of the Energy Policy Act (EPAct). This new statutory authority makes clear that the FERC may approve market-based rates for storage facilities, even if the proposer is unable to show lack of market power. When relying upon this new statutory provision, the FERC must find that: (1) market-based rates are in the public interest and necessary to encourage the construction of needed storage capacity, and (2) customers are adequately protected.

Similarly, in approving market-based rates for Wild Goose and Lodi, the CPUC also demonstrated a willingness to go beyond a simple reliance upon HHI's. In its Wild Goose expansion decision, for example, the CPUC noted that the geographic markets involved were highly concentrated for storage services and that only the broadest market definition resulted in an HHI of less than 1800.

Nevertheless, the CPUC recognized that HHI's provide only an incomplete picture of the possibility for market power to operate and turned next to the market share evidence, noting that where FERC has approved market-based rates for storage service, particularly in highly concentrated markets, generally market share has been low. The CPUC went on to cite evidence that "[m]arket share matters because `the smaller the percentage of total supply that a firm controls, the more severely it must restrict its own output in order to produce a given price increase, and the less likely it is that an output restriction will be profitable'," quoting the Horizontal Merger Guidelines from the U.S. Department of Justice, pp.8-9.)

The CPUC found that further analysis was necessary to determine whether Wild Goose could exercise market power even if it was found to possess it. To provide such a fuller picture of Wild Goose's potential to exercise market power, the CPUC determined that it must consider the remaining factors that influence that potential. Such factors were found to include alternatives to storage that affect the demand elasticity for storage injection and withdrawal.

Ultimately, the CPUC found record evidence that identified several potential alternatives. Such alternatives included transportation capacity, which in many situations is interchangeable with storage; and balancing services, that permit natural gas shippers to "balance" short-term discrepancies between gas receipts and deliveries without purchasing storage.

On the basis of this regulatory approach, which clearly went well beyond a simple reliance on HHI values, the CPUC approved market-based rates for both Wild Goose and Lodi. It should be mentioned, however, that the CPUC attached several regulatory conditions to its approval in both cases.

From the foregoing, it is clear that both the FERC and the CPUC have recognized that market-based rate approval may well be critical to obtaining private sector interest in and commitment to needed gas storage expansion and enhancement. And both agencies have demonstrated a willingness to take a broad approach in considering whether market-based gas storage rates can be justified under given circumstances.

The regulations promulgated by Order No. 678 hold promise of a coordinated, streamlined, and supportive environment for the market-based rate approval process as applied to storage improvements subject to FERC jurisdiction. With regard to storage improvements subject to CPUC jurisdiction, however, matters are not so clear.

In California, providing a simplified approach to market-based rate determinations, and streamlining the overall regulatory review process, would certainly help assure that storage improvements will be made as needed. Otherwise, at best, divergent policy views and competing market analyses may continue to cause delay, and waste resources.

Nonetheless, the CPUC's March 2, 2006 decision approving facilities and market-based rates associated with LGS's Kirby Hills Facility clearly provides some encouragement to those who support storage improvement projects in California. In that decision, the CPUC stated as follows:

We also agree that the Kirby Hills Facility is needed. As LGS points out, its Lodi Facility is fully subscribed, yet the recent open season demonstrated that there is a significant demand in Northern California for additional gas storage. Moreover, the recently-adopted Energy Action Plan II makes clear that both this Commission and the CEC consider additional in-state gas storage desirable in order to enhance reliability and mitigate price volatility.

It should be noted that the Kirby Hills decision is relatively simple and straightforward, and that it makes no mention whatever of HHI's. And while LGS would almost certainly prefer CPUC approvals with no conditions attached, the conditions imposed in the Kirby Hills decision appear to be part of a developing regulatory regime that has succeeded in encouraging significant storage improvements through market-based rate and other approvals in recent years.

Below, different approaches to market analysis using HHI's are outlined in Tables 36-39. Each of these approaches has been championed before the CPUC, and absent clear guidelines, each may continue to vie for a role in determining whether gas storage expansion and enhancements go forward. Nonetheless, each of these approaches, except the one outlined in Table 6, fails to give appropriate weight to widely acknowledged alternatives to storage services and therefore such approaches should be considered inaccurate and misleading.

For example, if one looks at the California storage market solely using working gas capacity, then SoCal's market share would be about 58%, with PG&E at about 20%, and Wild Goose and Lodi each in the 10-12% range (see

Table 37). The sum of the squares of these market shares (HHI) is 4009, indicating a "highly concentrated" market, well above the 1800 threshold.

Table 37 HHI based on CA storage field working gas capacity

Storage Field	Working Gas Capacity (Bcf)	Market Share (MS) Percent	MS**2
PG&E	41.0	19.5	380.8
SoCal Gas	122.1	58.1	3,377.4
Wild Goose	25.0	11.9	141.6
Lodi	22.0	10.5	109.6
Total	**210.1**	**100.0**	**4,009**

Similarly, as shown in Table 38, simply using peak-day deliveries from California storage fields will also yield an HHI a little more than double the concentrated market threshold of 1800.

Table 38 HHI based CA Storage Field Withdrawal Deliverability

Storage Field	Withdrawal Deliverability (MMcf/d)	Market Share (MS) Percent	MS**2
PG&E	1,710	28.9	835.8
SoCal Gas	3,175	53.7	2,881.2
Wild Goose	480	8.1	65.9
Lodi	550	9.3	86.5
Total	**6,520**	**100.0**	**3,869.3**

In its Wild Goose expansion decision, the CPUC pointed out that it might be appropriate to take only *noncore* capacity or deliverability that can actually be sold on the open market into account in a market power analysis. With this in mind, Table 39 includes California's noncore capacity, but excludes core capacity. Under this approach, the market shares for Lodi and Wild Goose rise to the 22-25% range, and PG&E's share drops precipitously. The HHI becomes 3405, still much higher than the concentrated market threshold, but lower than that calculated in

Table 37 using total gas capacity.

Table 39 HHI based on CA storage field *noncore only* working gas capacity

Storage Field	Working Gas Capacity (Bcf)	Market Share (MS) Percent	MS**2
PG&E	5.0	5.1	25.6
SoCal Gas	46.8	47.4	2,243.8
Wild Goose	25.0	25.3	640.3
Lodi	22.0	22.3	495.8
Total	**98.8**	**100.0**	**3,405**

Similarly,

Table 40 excludes core deliverability from the market analysis and focuses solely on noncore deliverability. On this basis, the HHI is 3708, well above the 1800 threshold.

Table 40 HHI based on non-core only Deliverability

Storage Field	Withdrawal Deliverability (MMcf/d)	Market Share (MS) Percent	MS**2
PG&E*	0	0.0	0.0
SoCal Gas	990	49.0	2,402.0
Wild Goose	480	23.8	564.7
Lodi	550	27.2	741.3
Total	**2,020**	**100.0**	**3,708.0**

* Calculated by subtracting 2001 firm deliverability

Table 40's analysis, however, does not take into account gas pipeline deliveries into California, or indigenous supplies. Under the FERC's Order No. 678 approach, both of these natural gas sources could be considered good alternatives to California-based storage services. As such, they would qualify for inclusion in market power analyses.

Table 41 presents a simplified, but illustrative, view taking all of these factors into account. Peak day pipeline deliverability into California, together with indigenous natural gas supplies, and non-core storage deliverability are combined in Table 41 to give a realistic representation of the market in which increased and enhanced storage services must compete. Table 41 does not, however, separate pipeline deliverability into core and non-core, nor take capacity release options or co-ownership of indigenous wells into account.

Table 41 California Pipeline and Storage Deliverability

Owner	Description	Capacity (MMcf/d)	Market Share (MS) %	MS**2
PG&E/PGT	Storage plus pipeline	3,887	24.7	608
SoCal Gas	Storage	3,175	20.1	406
Wild Goose	Storage	480	3.0	9
Lodi	Storage	550	3.5	12
Questar	Pipeline	87	0.6	0
MidAmerican	Pipeline	1,750	11.1	123
El Paso	Pipeline	3,340	21.2	449
KRT	Pipeline	775	4.9	24
Transwestern	Pipeline	120	0.8	1
Intrastate	Intrastate wells	989	6.3	39
Tuscarora	Pipeline	110	0.7	0
TransCanada	Pipeline	500	3.2	10
Total Pipeline plus storage deliverability		**15,763**	**100.0**	**1,682**

This broader definition of the market drops the HHI to 1682, *below the market concentration threshold*. As indicated above, this approach has been used by the FERC and its reliance on pipeline deliveries is consistent with recent CPUC's decisions involving Wild Goose and Lodi.

Alternative Market-Based Rates Methodologies

In addition to the approaches discussed above, the FERC has used the following approaches to test for market power in determining whether to approve market-based rate in electric cases.

Pivotal Supplier Analysis: The uncommitted pivotal supplier analysis[55] evaluates the potential of a company to exercise market power based on the control area's peak demand. The pivotal supplier analysis focuses on the ability to exercise market power unilaterally.

Wholesale Market Share Analysis: The wholesale market share analysis[56] measures for the four seasons if a company has a dominant position based on the uncommitted capacity owned or controlled by the company compared to the uncommitted capacity of the entire region under

[55] http://www.policy.rutgers.edu/ceeep/images/FFJune2004.pdf

[56] Rutgers, IBID

question. The FERC adopts the initial threshold of 20 percent for market participants *other* than the filer. A supplier that has a less than 20 percent share for all seasons satisfies this test.

Delivered Price Test: The test of last resort for the company that fails the uncommitted pivotal supplier analysis or the wholesale market share analysis is the delivered price test. The idea[57] is to evaluate the level of competition of the market of interest by determining the company's effective competitors – competitors that can deliver service at less than or equal to five percent over the market price.

5.3. Conclusions and Recommendations

The CEC and the CPUC have recognized that additional in-state gas storage is desirable in order to enhance reliability and mitigate price volatility. In this section some options are presented that could aid in meeting this objective while ensuring an appropriate review of market, environmental, and safety issues related to proposed new and expanded storage facilities and services.

Adopt Table 41's "Market" Definition for Gas Storage Market-Based Rate Determinations: As shown in Table 41, the gas storage market in California may be defined such that an HHI above 1800 no longer constrains near-term regulatory considerations of much needed gas storage improvements. This approach considers the California storage market statewide, and includes deliverability from non-core storage, indigenous gas supplies, and gas pipelines.

This definition of the storage market is in line with the FERC's Order No. 678. And, while several "market" definitions have competed for CPUC sanction in gas storage cases, there is no doubt that non-traditional alternatives to storage, such as those used in Table 41, have played a significant role in the CPUC's recent LGS and Wild Goose decisions.

Adoption of the Table 41 approach would simplify and expedite regulatory review of storage improvement proposals. It would do so by ending debate over how the California gas storage market should be viewed for regulatory purposes, using a "market" definition in accord with Energy Action Plan II's recognition that additional in-state gas storage is desirable in order to enhance reliability and mitigate price volatility. Such a definition would encourage not only new independent storage service providers to propose facilities in California, but also encourage existing participants, including SoCal Gas and PG&E, as well as LGS and Wild Goose, to expand existing facilities and offer more non-core storage.

Market-Based Rates for New Independent Storage Projects: In this approach[58,] CPUC regulation would consistently recognize a rebuttable presumption that new independent storage projects qualify for market-based rates. This approach is justified on the grounds that such new projects add incremental capacity to existing markets, thereby giving customers new choices for services, and with the provision that all market risks lie with the project's owners. The Commission could determine that market-based rates for new independent storage projects are just and reasonable because customers are better off than they would be if the project was not built.

[57] Rutgers, IBID

[58] https://www.ferc.gov/EventCalendar/Files/20041020081349-final-gs-report.pdf

Since the new project's owners assume all market risk and would have no captive customers to pass costs on to, they would be faced with selling storage services in order to cover costs and make a profit. Customers could always choose to use the new project or not, depending on their own assessment of the value. As a result, project sponsors would have to price their services at rates low enough to attract customers.

This approach appears to be fully in line with recent CPUC storage decisions, including its March 2, 2006 decision in the Kirby Hills case, where the CPUC stated as follows:

Under the Gas Storage decision (D.93-02-013) and its progeny, LGS -- not ratepayers -- will be fully at risk if the expected demand for storage and withdrawal capacity at the Kirby Hills Facility fails to materialize. Thus, it is reasonable to grant LGS's request for authority to charge market-based rates for the gas storage, withdrawal and related services at the new Facility. Granting such authority is also consistent with the manner in which we have treated LGS's Lodi facility.

A clear statement from the CPUC that similar treatment can be expected for all new independent storage projects could be quite helpful.

Reviewing the Market Power Test for Adequacy in Storage Markets: An alternative[59] to granting market-based rates to all new independent storage projects would be to determine the current test for market power does not accurately measure it. Some storage developers assert that they are unable to secure long-term service agreements as pipelines do in construction applications. Accordingly, to the extent a storage provider could demonstrate an inability to secure firm service contracts for the entire capacity of its storage field, for terms exceeding some specified time, the CPUC or the FERC could find it lacked market power, and grant market-based rate authority. The Commissions would likely want to establish guidelines, in advance, for such capacity offerings to ensure they were conducted on an open and transparent basis, and barriers to longer-term contracts were not established. The mitigation measures discussed in the previous section could be applicable to these alternative approaches, as well.

Increase Storage Capacity and Storage Requirements[60]: The CPUC approves the storage requirements for gas LDC's to serve core customers but has deregulated storage requirements for noncore customers and electric generators. The CPUC could evaluate the feasibility of expanding utility-owned storage capacity to enable the utilities to take advantage of lower summer prices to benefit core customers. In addition, the state could determine if expedited permitting processes are needed to accelerate the development of non-utility-owned underground storage capacity. Competition between utility and non-utility providers could benefit natural gas customers.

Expedited Siting for Onshore LNG Peak Shaving Plants: The complex permitting process for LNG peak shaving facilities could be simplified, with one lead agency or regulatory body controlling the process. All other relevant Federal, local, regional, and State agencies would be part of the process, but one environmental impact statement could be used, for instance, for

---

[59] FERC 2004 (IBID)

[60] http://sor.govoffice3.com/vertical/Sites/%7B3BDD1595-792B-4D20-8D44-626EF05648C7%7D/uploads/%7B9EDD76BA-35AC-41AD-940F-E62DDBFEB93E%7D.HTM

review by all parties. Separating the decision process for LNG terminals and LNG peak shaving facilities and educating the California public as to these differences could go a long way toward removing the emotional issues related to LNG terminal siting. This would seem to be an appropriate topic for consideration by the California LNG Interagency Permitting Working Group.

Cost of Service Adjustment: A cost-based rate option[61] for encouraging investment in underground storage could be accomplished through adjustments to the cost of service, i.e., the annual revenue requirement of the project. For example, an equity return premium to reflect higher risks associated with storage development, or accelerated depreciation might induce entry by allowing higher maximum rates. In this example higher rates would occur because (1) the normal cost of equity would be increased by a premium to reflect higher risk or simply to incentivize development, and (2) the depreciable life of the storage project's assets would be shortened. Accelerated depreciation allows the full cost of capital to be recovered more quickly.

Revise or Waive the FERC Policies: Waivers of, and exemptions from, certain regulatory requirements also might encourage storage improvements. [62] The Commission could consider initiating an industry dialogue to explore possible improvements to the current process for environmental review and certificate authorization.

[61] FERC (2004) IBID

[62] FERC (2004) IBID

6.0 References

Adapted from USA Pro/California Energy Commission, "California LNG Transportation Fuel Supply And Demand Assessment", January 2002, with modifications

Prometheus Energy Press Release, "Bowerman LNG Plant Achieves Production Targets", January 3, 2008

(Prometheus Produces World's First Commercial LNG from Landfill Gas; Targeted for Public Transit Fuel, 2007)

(B.C. Price, Black & Veatch Pritchard Inc., Overland Park, Kansas, 2003)

(B.C. Price, Black & Veatch Pritchard Inc., Overland Park, Kansas, 2003)

B.C. Price, Black & Veatch Pritchard Inc., Overland Park, Kansas. (2003, Janurary 3). *Small-scale LNG Facility Development*. Retrieved January 15, 2007, from Black & Veatch: http://www.bv-russia.com/news/articles/jan03/small_scale_lng_facility.htm

Northstar Ind. (2007, Jan 15). Retrieved Jan 15, 2007, from Northstar Ind.: http://www.northstarind.com/lngfaqs.html

Prometheus Produces World's First Commercial LNG from Landfill Gas; Targeted for Public Transit Fuel. (2007, January 26). Retrieved January 17, 2008, from Green Car Congress: http://www.greencarcongress.com/2007/01/prometheus_prod.html

Gas Research Institute, GRI-90/0139, Task 3 Topical Report (March 1989-April 1990), "Economic Analysis of Low-Pressure Natural Gas Vehicle Storage Technology", April 1990, Pages 29-30

Gas Research Institute, GRI-95/0068, Final Report, "Absorbed Natural Gas (ANG) Research conducted by Atlanta Gas Light Absorbent Research Group (AGLARG)", June 1994, Page 11

Documents and phone conversations provided by Paul Britton, Managing Director, EnerSea Transport LLC, Houston, Texas

Information provided by Dr. Chinbay Fan, Gas Technology Institute regarding current absorbed natural gas materials

Arthur D. Little, Final Report, *Liquefied Natural Gas for Heavy-Duty Transportation.* (May, 2001). Final Report No. FR-01-101.

Charles Powars-St. Croix Research,Gary Pope-USA PRO & Associates. Final Report. *CALIFORNIA LNG TRANSPORTATION: FUEL SUPPLY AND DEMAND ASSESSMENT*. (January, 2002)

Clean Vehicle Education Foundation. *Codes, Standards and Advisories Applicable to Natural Gas Vehicles and Infrastructure.*

Brookhaven National Laboratory, Energy Sciences and Technology Department, Natural Gas Vehicle Systems Program. *(http://www.bnl.gov/est/erd/NGVSP.asp)*

Davis Engineering & Associates Limited, Final Report, *IDENTIFICATION OF COMPRESSED NATURAL GAS RESEARCH &DEVELOPMENT AND FABRICATION OPPORTUNITIES FOR THE PROVINCE OF NEWFOUNDLAND AND LABRADOR*. (December 2002)

http://www.moregastech.com/index.php, Adsorbed Natural Gas, Natural Gas Storage, Natural Gas Vehicles.

EnerSea Transport, LLC. *EnerSea's VOLANDS™ For Storage & Peaking Demand Support*. (2007)

Pipeline and Gas Journal. *Portable Gas Supplies used for Treasure Island Customers.* (article, December 2007 issue).

Gas International Magazine. *Adsorbed NG moves closer*. (Volume 47, Issue 4, May 2007)

EnerSea Transport, LLC. *EnerSea's CNG Solution: VOTRANS™ and VOLANDS™ General Background, General Background Information.* (2007)

Gas Technology Institute. *Small-Scale Natural Gas Liquefier.* http://www.gastechnology.org. (April 2007)

Gas Technology Institute. *Engineering Analyses for Underground Storage of Natural Gas as a Hydrate.* (2005)

AKER KVAERNER, *Natural Gas Hydrate, NGH: A method for gas storage & transport.* Oscar Fr. Graff (December 2004)

NEW YORK STATE ELECTRIC & GAS CORPORATION. *LRC STORAGE TECHNOLOGY.* (November 1999)

Annals of the New York Academy of Sciences. *Feasibility of Storing Natural Gas in Hydrates Commercially.* (R. E. ROGERS AND YU ZHONG), Volume 912, GAS HYDRATES: CHALLENGES FOR THE FUTURE Page 843-850, January 2000.

Vander & Vander Alternative Energy Solutions. *Storage of Cold Compressed Natural Gas (CCNG) in Solution-Mined Salt Caverns.* NYSERDA Phase-2B Demonstration. (May 2006)

Gas Tips: Technology Development in Natural Gas Exploration, Production, and Processing. *Gas Hydrate Exploration and Production: Dispelling the Myths*. Volume 12, Number 2, 2006

7.0 Section 3.0 Appendix

7.1. Northern California Region

Historical Raw Data Tables

Table 42 NR Historical Data

North Region Gas Deliveries 2002

	Monthly Average Deliveries (MMcf/Day)							Storage Usage PG&E Storage		
Month	Core	Total Industrial	Industrial (minus CoGen)	Cogeneration	Electric Generation	Off-system deliveries	Total	Storage Injection	Storage Withdrawals	Storage Inventory*
January	1601	464	242	222	791	166	3022	106	-709	69450
February	1211	444	210	234	744	147	2547	186	-226	68893
March	1027	446	246	199	926	96	2494	182	-143	71283
April	751	417	225	192	724	251	2143	285	0	79823
May	632	424	205	218	716	255	2027	283	-3	88312
June	522	597	358	239	694	390	2203	219	0	94243
July	472	784	526	258	874	418	2547	117	-109	94191
August	503	866	608	258	814	427	2610	60	-86	93576
September	485	849	606	243	778	371	2483	153	-162	97072
October	600	765	523	242	669	289	2323	135	-126	98335
November	879	735	505	230	722	170	2506	65	-92	97679
December	1314	748	533	216	729	201	2992	0	-440	84282

* Storage Inventory value reflects inventory on the last day of the month

North Region Gas Deliveries 2004

	Monthly Average Deliveries (MMcf/Day)							Storage Usage PG&E Storage		
Month	Core	Total Industrial	Industrial (minus CoGen)	Cogeneration	Electric Generation	Off-system deliveries	Total	Storage Injection	Storage Withdrawals	Storage Inventory
January	1495	720	513	206	443	235	2892	0	-657	61323
February	1279	683	478	205	428	457	2847	0	-474	47715
March	717	617	440	177	428	377	2139	249	-353	53256
April	636	618	399	219	459	386	2099	267	0	61142
May	508	616	406	209	465	357	1946	389	0	73231
June	466	667	444	223	419	380	1931	323	0	83185
July	430	777	553	225	713	452	2372	245	-72	89346
August	416	861	627	234	667	532	2476	177	-134	93518
September	437	869	628	240	604	529	2438	180	0	98697
October	640	719	490	228	466	316	2141	103	-90	99622
November	1081	755	509	246	467	365	2667	77	-247	97605
December	1425	733	506	227	437	576	3171	69	-411	86366

* Storage Inventory value reflects inventory on the last day of the month

North Region Gas Deliveries 2005

Month	Monthly Average Deliveries (MMcf/Day)							Storage Usage PG&E Storage		
	Core	Total Industrial	Industrial (minus CoGen)	Cogeneration	Electric Generation	Off-system deliveries	Total	Storage Injection	Storage Withdrawals	Storage Inventory
January	1609	727	494	232	432	404	3172	0	-694	65062
February	1111	712	491	221	334	417	2574	65	-160	61412
March	834	661	452	209	349	318	2162	254	-21	68318
April	751	624	415	210	309	261	1946	272	-20	76137
May	530	637	423	214	257	236	1660	349	0	86948
June	472	686	454	232	303	178	1640	286	0	95786
July	396	769	539	229	680	394	2239	164	-207	95210
August	410	865	630	235	684	292	2250	125	-134	94406
September	482	809	601	209	526	173	1990	155	-26	98969
October	555	736	517	219	501	144	1936	73	-71	100165
November	848	698	506	192	515	58	2119	61	-141	98649
December	1204	682	499	183	512	60	2459	125	-508	87937

* Storage Inventory value reflects inventory on the last day of the month

North Region Gas Deliveries 2006

Month	Monthly Average Deliveries (MMcf/Day)							Storage Usage PG&E Storage		
	Core	Total Industrial	Industrial (minus CoGen)	Cogeneration	Electric Generation	Off system deliveries	Total	Storage Injection	Storage Withdrawals	Storage Inventory
January	1312	650	485	165	291	78	2330	68	-272	81398
February	1152	687	517	170	376	78	2293	95	-328	75513
March	1238	706	537	169	292	102	2339	200	-289	70568
April	806	644	460	185	174	53	1678	266	-9	78131
May	507	687	488	199	319	124	1637	295	0	87086
June	450	710	503	206	486	242	1888	219	-78	93878
July	400	814	603	211	803	567	2585	124	-337	89282
August	452	916	700	217	616	518	2502	128	-104	92551
September	493	904	691	213	555	287	2239	191	-45	98380
October	586	834	621	213	510	206	2136	94	-83	99859
November	908	741	537	203	426	52	2128	45	-380	96470
December	1441	801	577	224	465	83	2790	0	-512	80349

* Storage Inventory value reflects inventory on the last day of the month

North Region Gas Deliveries 2003

Month	*Monthly Average Deliveries (MMcf/Day)*							Storage Usage PG&E Storage		
	Core	Total Industrial	Industrial (minus CoGen)	Cogeneration	Electric Generation	Off-system deliveries	Total	Storage Injection	Storage Withdrawals	Storage Inventory
January	1141	724	540	184	500	145	2510	0	-418	71126
February	1212	688	495	193	582	24	2506	0	-605	54312
March	852	590	449	142	497	282	2222	168	-322	49560
April	885	630	474	156	379	396	2291	343	-63	59647
May	616	608	429	179	279	296	1799	363	0	71125
June	478	660	458	202	384	243	1765	320	0	80036
July	435	728	515	213	770	309	2242	162	-31	85052
August	439	819	604	216	624	285	2167	133	-144	87049
September	428	833	623	210	604	284	2149	234	0	94246
October	522	695	498	197	532	302	2051	202	0	99766
November	1105	695	500	196	407	276	2484	93	-165	96931
December	1343	716	496	220	359	447	2865	0	-488	81956

* Storage Inventory value reflects inventory on the last day of the month

Forecast Data Table

Table 43 NR Monthly Forecast Data

Base Case Forecast--Calendar Basis
(Average Temperature Year
November 2005 Forecast

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL	Jan-08	Feb-08	Mar-08	Apr-08
CORE																	
RESIDENTIAL																	
RESIDENTIAL IM	31,346	24,152	18,925	14,260	11,093	8,578	7,880	7,149	7,606	9,628	17,769	29,688	188,077	32,072	24,746	19,375	14,724
RES IM TRANS	58	45	35	27	21	16	15	13	14	18	33	55	350	60	46	36	27
RESIDENTIAL MM	2,761	2,354	2,219	2,002	1,764	1,647	1,579	1,448	1,486	1,604	2,416	2,894	24,174	2,825	2,412	2,272	2,067
RES MM TRANS	12	10	10	9	8	7	7	6	7	7	11	13	107	13	11	10	9
TOTAL RES	34,178	26,562	21,189	16,297	12,886	10,248	9,481	8,617	9,113	11,257	20,229	32,650	212,708	34,969	27,215	21,693	16,828
COMMERCIAL																	
SML COM SALES	9,803	7,991	7,300	5,706	5,091	4,445	4,098	3,999	4,105	5,029	6,956	9,702	74,224	10,084	8,232	7,512	5,839
SML COM TRANS	838	692	601	445	364	284	238	237	269	317	518	748	5,550	862	712	619	456
LRG COM SALES	615	570	551	575	564	522	605	751	748	766	773	733	7,772	628	583	563	584
LRG COM TRANS	26	24	23	24	22	22	26	30	27	29	34	33	321	27	24	23	24
TOTAL COM	11,283	9,276	8,475	6,751	6,040	5,272	4,968	5,016	5,148	6,141	8,282	11,216	87,867	11,601	9,552	8,717	6,903
INTERDEPT																	
GNR1	25	19	12	11	8	6	4	3	5	7	17	23	140	25	19	12	11
GNR2	4	4	2	2	3	2	2	2	2	3	3	4	33	4	4	2	2
EG	372	333	367	197	313	258	425	431	413	323	423	446	4,300	372	334	367	197
TOTAL INTERDEPARTMENTAL	401	356	381	210	324	266	431	436	420	333	443	473	4,473	401	357	381	210
NATURAL GAS VEHICLE																	
NGV1--INTERDEPARTMENTAL	5	5	6	6	7	7	6	6	7	9	6	7	78	5	6	7	7
NGV1--NON-INTERDEPARTMENTAL	129	129	131	138	137	128	123	127	145	155	149	144	1,637	148	148	151	159
NGV2--NON-INTERDEPARTMENTAL	19	17	21	21	21	20	17	19	19	17	16	17	225	21	19	24	24
TOTAL NGV	152	151	159	166	165	154	146	152	171	181	172	169	1,940	174	173	182	190
TOTAL CORE	46,014	36,345	30,204	23,424	19,415	15,941	15,026	14,222	14,852	17,912	29,126	44,507	306,987	47,145	37,297	30,972	24,130
NONCORE																	
INDUSTRIAL																	
IND DISTR	2,599	2,249	2,275	2,124	2,008	1,855	1,884	2,029	1,992	2,221	2,331	2,452	26,020	2,650	2,293	2,320	2,152
IND TRANSM	9,964	8,410	9,020	8,587	8,765	8,898	11,702	14,106	13,626	10,764	9,971	9,776	123,589	10,061	8,492	9,108	8,636
IND BACKBONE	245	207	222	211	216	219	288	347	335	265	245	240	3,039	247	209	224	212
TOTAL IND	12,808	10,866	11,516	10,923	10,989	10,971	13,874	16,482	15,953	13,250	12,548	12,469	152,648	12,959	10,994	11,651	11,000
ELECTRIC GENERATION																	
COGEN-DIST																	
COGEN-LT																	
EG-LT																	
EG-BACKBONE																	
TOTAL EG																	
NGV4	41	39	44	42	43	44	44	46	43	42	39	42	508	41	39	44	42
TOTAL NON EG NONCORE	12,849	10,905	11,560	10,965	11,032	11,015	13,918	16,528	15,996	13,292	12,587	12,511	153,156	13,000	11,033	11,695	11,042
WHOLESALE																	
CORE																	
PALO ALTO	446	370	346	271	222	164	170	168	168	215	333	432	3,306	446	384	345	272
COALINGA	41	32	22	13	11	9	7	7	7	11	26	37	224	41	32	23	13
WEST COAST-CASTLE	7	5	5	4	4	3	3	3	4	4	5	7	54	7	5	5	4
WEST COAST-MATHER	20	11	8	7	5	4	3	3	4	6	11	16	98	20	11	8	7
ISLAND ENERGY	9	7	8	5	4	3	2	2	2	4	6	7	59	9	7	8	5
ALPINE	11	9	7	5	3	2	2	2	2	3	6	9	59	12	11	7	5
TOTAL WHOLESALE CORE	533	434	396	306	249	185	188	185	186	243	387	507	3,799	535	449	396	307
NONCORE																	
WEST COAST-CASTLE	3	2	2	2	1	1	0	0	0	1	2	3	16	3	2	2	2
TOTAL WHOLESALE	536	436	398	307	250	186	188	185	186	244	389	510	3,815	538	451	398	309
SHRINKAGE																	
GAS DEPT USE	229	256	342	341	188	269	369	382	409	339	365	387	3,874	232	264	348	350
LUAF	1,584	1,329	768	588	491	333	277	285	322	678	1,769	2,021	10,443	1,604	1,371	782	603
TOTAL SHRINKAGE	1,813	1,585	1,110	929	679	602	646	666	731	1,016	2,134	2,408	14,318	1,836	1,634	1,130	953
TOTAL DEMAND	61,211	49,270	43,272	35,625	31,376	27,744	29,778	31,601	31,765	32,464	44,235	59,935	478,276	62,519	50,415	44,196	36,435
TOTAL Demand in MDth/d	168	135	119	98	86	76	82	87	87	89	121	164	1310	171	138	121	100

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	TOTAL	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	TOTAL
11,456	8,858	8,056	7,309	7,776	9,797	18,053	30,210	192,433	32,678	25,242	19,751	14,903	11,597	8,966	8,145	7,390	7,862	9,890	18,209	30,498	195,129
21	16	15	14	14	18	34	56	358	61	47	37	28	22	17	15	14	15	18	34	57	363
1,822	1,700	1,615	1,481	1,519	1,633	2,455	2,945	24,744	2,878	2,460	2,316	2,092	1,844	1,721	1,632	1,497	1,536	1,648	2,476	2,973	25,073
8	8	7	7	7	7	11	13	110	13	11	10	9	8	8	7	7	7	7	11	13	111
13,307	10,582	9,693	8,810	9,317	11,455	20,552	33,224	217,645	35,630	27,760	22,114	17,032	13,470	10,711	9,800	8,907	9,419	11,564	20,730	33,541	220,677
5,210	4,547	4,182	4,081	4,189	5,116	7,065	9,861	75,918	10,218	8,347	7,612	5,917	5,278	4,606	4,233	4,130	4,240	5,172	7,135	9,963	76,852
372	290	243	242	275	322	527	760	5,679	873	722	627	462	377	294	246	245	278	326	532	768	5,749
572	529	613	760	757	773	779	740	7,880	631	586	565	587	575	532	616	763	760	776	781	742	7,913
22	23	27	30	27	29	35	33	325	27	24	24	25	22	23	27	30	27	30	35	33	326
6,175	5,389	5,064	5,112	5,248	6,241	8,405	11,394	89,802	11,749	9,680	8,828	6,989	6,252	5,455	5,121	5,169	5,306	6,304	8,482	11,507	90,841
8	6	4	3	5	7	17	23	140	25	19	12	11	8	6	4	3	5	7	17	23	140
3	2	2	2	2	3	3	4	33	4	4	2	2	3	2	2	2	2	3	3	4	33
313	257	425	429	413	323	423	448	4,299	372	334	367	197	313	257	425	429	413	323	423	448	4,299
324	265	431	434	420	333	443	475	4,472	401	357	381	210	324	265	431	434	420	333	443	475	4,472
8	8	7	7	8	10	7	8	87	6	6	8	8	9	8	8	7	9	11	8	9	97
158	147	142	146	167	178	172	166	1,882	170	171	174	183	182	169	163	168	192	205	198	190	2,165
23	22	19	21	21	19	18	19	250	23	22	26	26	26	25	21	24	23	22	20	22	279
189	177	168	174	196	207	197	193	2,220	199	198	208	218	216	202	192	199	224	237	225	221	2,541
19,996	16,413	15,356	14,531	15,180	18,236	29,597	45,286	314,139	47,979	37,995	31,531	24,449	20,262	16,633	15,544	14,709	15,369	18,437	29,880	45,743	318,531
2,034	1,879	1,907	2,054	2,016	2,246	2,358	2,480	26,390	2,659	2,301	2,327	2,161	2,043	1,887	1,916	2,063	2,025	2,257	2,368	2,491	26,498
8,815	8,948	11,774	14,192	13,709	10,834	10,036	9,840	124,443	10,074	8,503	9,119	8,657	8,836	8,970	11,810	14,236	13,752	10,868	10,067	9,871	124,763
217	220	290	349	337	266	247	242	3,060	248	209	224	213	217	221	290	350	338	267	248	243	3,068
11,066	11,047	13,971	16,595	16,062	13,347	12,640	12,562	153,893	12,981	11,013	11,671	11,031	11,096	11,077	14,017	16,649	16,115	13,392	12,683	12,605	154,329
43	44	44	46	43	42	39	42	508	41	39	44	42	43	44	44	46	43	42	39	42	508
11,108	11,090	14,015	16,641	16,105	13,389	12,679	12,604	154,401	13,022	11,051	11,715	11,073	11,139	11,120	14,061	16,695	16,158	13,434	12,722	12,647	154,837
221	164	171	166	169	215	332	434	3,319	445	370	346	272	220	165	171	166	169	215	333	434	3,306
11	9	7	7	7	11	27	37	228	42	33	23	14	12	10	7	7	7	12	28	38	233
4	3	3	3	4	4	5	7	54	7	5	5	4	4	3	3	3	4	4	5	7	54
5	4	3	3	4	6	11	16	98	20	11	9	7	5	4	3	3	4	6	11	16	98
4	3	2	2	2	4	6	7	59	9	7	8	5	4	3	2	2	2	4	6	7	59
3	2	2	2	2	3	6	10	66	12	11	7	5	3	2	2	2	2	3	6	10	66
249	186	189	184	188	243	387	510	3,823	535	436	398	308	248	187	189	184	188	243	388	511	3,815
1	1	0	0	0	1	2	3	16	3	2	2	2	1	1	0	0	0	1	2	3	16
250	186	189	184	188	244	389	513	3,839	538	438	400	309	249	187	189	184	188	244	390	514	3,831
191	274	375	380	408	339	368	389	3,918	234	260	347	353	191	274	373	382	409	342	372	391	3,928
499	340	281	283	321	679	1,786	2,028	10,577	1,623	1,353	779	608	500	339	280	285	322	684	1,805	2,041	10,619
689	614	656	664	730	1,018	2,154	2,417	14,495	1,857	1,613	1,126	960	692	613	652	667	731	1,026	2,178	2,433	14,547
32,043	28,303	30,215	32,019	32,203	32,887	44,819	60,820	486,874	63,396	51,098	44,771	36,791	32,342	28,554	30,446	32,255	32,446	33,140	45,170	61,336	491,745
88	78	83	88	88	90	123	167	1334	174	140	123	101	89	78	83	88	89	91	124	168	1347

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	TOTAL	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11
33,051	25,547	19,982	15,041	11,704	9,048	8,213	7,451	7,927	9,960	18,327	30,716	196,968	33,384	25,819	20,189	15,178	11,811	9,131	8,283	7,515	7,995
62	48	37	28	22	17	15	14	15	19	34	57	367	62	48	38	28	22	17	15	14	15
2,911	2,490	2,343	2,111	1,861	1,737	1,646	1,509	1,549	1,660	2,492	2,994	25,303	2,937	2,514	2,365	2,128	1,876	1,751	1,658	1,521	1,560
13	11	10	9	8	8	7	7	7	7	11	13	112	13	11	11	10	8	8	7	7	7
36,036	28,096	22,373	17,189	13,595	10,810	9,882	8,981	9,498	11,646	20,864	33,780	222,749	36,397	28,393	22,602	17,344	13,718	10,907	9,965	9,057	9,577
10,320	8,435	7,689	5,975	5,330	4,651	4,271	4,168	4,278	5,215	7,188	10,041	77,561	10,406	8,508	7,754	6,025	5,375	4,690	4,305	4,200	4,312
882	730	633	466	381	297	248	247	281	328	536	774	5,803	889	736	639	470	384	299	250	249	283
631	587	566	587	575	532	615	763	760	775	780	741	7,912	630	586	565	586	574	531	614	761	758
27	24	24	25	22	23	27	30	27	30	35	33	326	27	24	23	24	22	23	27	30	27
11,861	9,776	8,912	7,053	6,308	5,503	5,161	5,208	5,346	6,348	8,538	11,589	91,602	11,952	9,855	8,981	7,105	6,354	5,543	5,195	5,240	5,380
25	19	12	11	8	6	4	3	5	7	17	23	140	25	19	12	11	8	6	4	3	5
4	4	2	2	3	2	2	2	2	3	3	4	33	4	4	2	2	3	2	2	2	2
372	334	367	197	313	257	425	429	413	323	423	448	4,299	372	334	367	197	313	257	425	429	413
401	357	381	210	324	265	431	434	420	333	443	475	4,472	401	357	381	210	324	265	431	434	420
7	7	9	9	10	9	9	8	10	12	9	10	108	8	8	10	10	11	10	10	9	11
187	188	191	201	200	186	180	185	211	225	217	209	2,381	206	206	210	222	220	205	197	204	232
26	24	29	30	29	27	23	26	26	24	22	24	311	29	27	33	33	32	30	26	29	29
219	219	229	240	238	223	211	220	247	261	248	244	2,801	242	241	253	264	263	246	233	242	272
48,518	38,447	31,895	24,691	20,465	16,801	15,685	14,843	15,511	18,588	30,093	46,088	321,625	48,992	38,845	32,216	24,923	20,659	16,960	15,824	14,974	15,650
2,661	2,302	2,329	2,161	2,043	1,887	1,915	2,063	2,025	2,255	2,367	2,489	26,499	2,654	2,296	2,323	2,155	2,037	1,882	1,910	2,057	2,019
10,074	8,503	9,119	8,650	8,829	8,963	11,791	14,213	13,729	10,844	10,045	9,849	124,608	10,023	8,460	9,073	8,605	8,783	8,916	11,730	14,139	13,658
248	209	224	213	217	220	290	349	338	267	247	242	3,064	246	208	223	212	216	219	288	348	336
12,983	11,014	11,673	11,024	11,089	11,070	13,996	16,625	16,091	13,365	12,659	12,580	154,171	12,924	10,964	11,619	10,972	11,037	11,017	13,929	16,544	16,013
41	39	44	42	43	44	44	46	43	42	39	42	508	41	39	44	42	43	44	44	46	43
13,024	11,053	11,716	11,066	11,132	11,113	14,040	16,671	16,135	13,407	12,698	12,622	154,679	12,964	11,003	11,663	11,014	11,079	11,061	13,973	16,590	16,056
444	370	346	272	220	165	170	167	169	214	333	434	3,306	444	370	346	271	221	165	169	168	169
43	34	24	14	12	10	8	8	8	12	28	39	238	44	34	24	14	12	10	8	8	8
7	5	5	4	4	3	3	3	4	4	5	7	54	7	5	5	4	4	3	3	3	4
20	11	9	7	5	4	3	3	4	6	11	16	98	20	11	9	7	5	4	3	3	4
9	7	8	5	4	3	2	2	2	4	6	7	59	9	7	8	5	4	3	2	2	2
12	11	7	5	3	2	2	2	2	3	6	10	66	12	11	7	5	3	2	2	2	2
535	437	399	308	248	187	188	185	188	242	390	512	3,820	536	438	399	308	249	187	188	186	189
3	2	2	2	1	1	0	0	0	1	2	3	16	3	2	2	2	1	1	0	0	0
538	439	401	310	250	187	189	185	189	243	392	515	3,836	539	440	401	309	251	188	188	186	189
238	266	354	358	194	279	381	391	417	349	378	397	4,001	241	269	360	363	198	284	389	402	427
1,650	1,382	794	617	507	346	286	291	328	699	1,832	2,071	10,803	1,670	1,401	808	625	518	352	292	299	336
1,889	1,647	1,148	974	701	625	666	682	745	1,048	2,210	2,468	14,804	1,911	1,670	1,168	987	716	636	682	701	763
63,968	51,586	45,160	37,041	32,548	28,726	30,580	32,381	32,579	33,286	45,393	61,693	494,943	64,406	51,958	45,448	37,234	32,705	28,844	30,666	32,450	32,657
175	141	124	101	89	79	84	89	89	91	124	169	1356	176	142	125	102	90	79	84	89	89

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

Oct-11	Nov-11	Dec-11	TOTAL	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	TOTAL	Jan-13	Feb-13	Mar-13	Apr-13	May-13
10,037	18,456	30,953	198,751	33,592	25,990	20,318	15,260	11,876	9,181	8,327	7,555	8,037	10,083	18,533	31,097	199,850	33,818	26,174	20,458	15,363	11,956
19	34	58	370	63	48	38	28	22	17	16	14	15	19	35	58	372	63	49	38	29	22
1,671	2,507	3,014	25,503	2,959	2,533	2,382	2,142	1,888	1,762	1,669	1,530	1,570	1,680	2,520	3,031	25,668	2,979	2,551	2,399	2,156	1,901
8	11	14	115	13	11	11	10	8	8	7	7	7	7	11	13	114	13	11	11	10	8
11,734	21,008	34,038	224,739	36,627	28,583	22,749	17,440	13,794	10,968	10,019	9,106	9,630	11,790	21,099	34,199	226,004	36,872	28,786	22,905	17,557	13,888
5,253	7,237	10,111	78,176	10,470	8,564	7,803	6,063	5,408	4,719	4,330	4,225	4,338	5,282	7,272	10,163	78,636	10,530	8,615	7,847	6,096	5,438
331	539	780	5,849	895	741	643	473	386	301	251	250	284	333	542	783	5,883	900	746	646	476	388
773	777	738	7,890	627	583	562	583	571	528	611	757	754	769	772	734	7,850	624	581	559	580	568
29	35	33	325	27	24	23	24	22	23	27	30	27	29	34	33	324	27	24	23	24	22
6,386	8,587	11,662	92,240	12,019	9,912	9,030	7,143	6,388	5,571	5,219	5,263	5,403	6,412	8,621	11,713	92,693	12,081	9,965	9,076	7,176	6,416
7	17	23	140	25	19	12	11	8	6	4	3	5	7	17	23	140	25	19	12	11	8
3	3	4	33	4	4	2	2	3	2	2	2	2	3	3	4	33	4	4	2	2	3
323	423	448	4,299	372	334	367	197	313	257	425	429	413	323	423	448	4,299	372	334	367	197	313
333	443	475	4,472	401	357	381	210	324	265	431	434	420	333	443	475	4,472	401	357	381	210	324
13	10	12	121	8	9	11	11	12	12	11	10	13	15	11	13	135	9	10	12	12	13
248	239	230	2,619	220	221	225	237	235	219	211	218	248	265	256	246	2,803	236	236	241	254	252
27	25	27	347	32	30	37	37	36	34	29	33	32	30	28	30	387	36	34	41	41	40
288	274	269	3,087	260	260	273	285	283	265	251	261	293	310	294	289	3,324	281	279	294	307	305
18,741	30,312	46,444	324,538	49,307	39,111	32,432	25,078	20,789	17,069	15,919	15,064	15,746	18,844	30,457	46,676	326,493	49,635	39,386	32,656	25,250	20,933
2,249	2,360	2,483	26,424	2,640	2,284	2,310	2,144	2,027	1,872	1,900	2,047	2,009	2,238	2,349	2,471	26,292	2,627	2,273	2,299	2,134	2,017
10,788	9,994	9,798	123,969	9,972	8,417	9,027	8,564	8,741	8,873	11,675	14,073	13,594	10,741	9,950	9,755	123,383	9,918	8,371	8,978	8,516	8,693
265	246	241	3,048	245	207	222	211	215	218	287	346	334	264	245	240	3,034	244	206	221	209	214
13,302	12,600	12,522	153,442	12,857	10,908	11,559	10,919	10,983	10,964	13,863	16,466	15,938	13,243	12,543	12,466	152,709	12,789	10,850	11,498	10,860	10,924
42	39	42	508	41	39	44	42	43	44	44	46	43	42	39	42	508	41	39	44	42	43
13,344	12,639	12,564	153,950	12,898	10,946	11,603	10,961	11,026	11,007	13,907	16,512	15,981	13,285	12,582	12,508	153,217	12,830	10,889	11,542	10,902	10,967
214	333	433	3,305	444	370	346	271	221	165	169	168	169	214	333	433	3,305	444	370	346	271	221
12	29	40	243	45	35	25	15	12	10	8	8	8	12	29	41	248	46	36	25	15	13
4	5	7	54	7	5	5	4	4	3	3	3	4	4	5	7	54	7	5	5	4	4
6	11	16	98	20	11	9	7	5	4	3	3	4	6	11	16	98	20	11	9	7	5
4	6	7	59	9	7	8	5	4	3	2	2	2	4	6	7	59	9	7	8	5	4
3	6	10	66	12	11	7	5	3	2	2	2	2	3	6	10	66	12	11	7	5	3
242	390	512	3,824	537	439	400	308	250	187	186	186	189	243	391	513	3,829	538	439	400	308	250
1	2	3	16	3	2	2	2	1	1	0	0	0	1	2	3	16	3	2	2	2	1
243	392	515	3,840	540	440	402	309	251	188	188	186	189	244	393	515	3,845	541	441	402	310	251
361	389	408	4,090	246	279	367	366	203	290	398	411	433	364	395	412	4,163	248	278	373	372	206
722	1,884	2,128	11,035	1,700	1,449	825	631	530	360	299	306	341	728	1,914	2,149	11,232	1,720	1,448	838	641	539
1,083	2,273	2,536	15,125	1,946	1,727	1,192	998	733	649	697	717	774	1,092	2,309	2,561	15,396	1,968	1,726	1,212	1,013	746
33,411	45,616	62,058	497,452	64,691	52,225	45,630	37,346	32,799	28,913	30,712	32,479	32,689	33,465	45,741	62,260	498,950	64,974	52,442	45,812	37,474	32,896
92	125	170	1363	177	143	125	102	90	79	84	89	90	92	125	171	1367	178	144	126	103	90

GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	TOTAL	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	TOTAL	Jan-15
9,242	8,377	7,600	8,086	10,135	18,619	31,255	201,083	34,013	26,334	20,579	15,452	12,026	9,296	8,421	7,640	8,128	10,180	18,695	31,396	202,161	34,186
17	16	14	15	19	35	58	374	63	49	38	29	22	17	16	14	15	19	35	58	376	64
1,774	1,679	1,540	1,580	1,689	2,532	3,046	25,825	2,996	2,567	2,413	2,169	1,912	1,784	1,688	1,548	1,588	1,696	2,542	3,060	25,963	3,011
8	7	7	7	8	11	14	115	13	11	11	10	8	8	8	7	7	8	11	14	115	13
11,041	10,079	9,161	9,687	11,850	21,197	34,373	227,397	37,085	28,962	23,041	17,659	13,969	11,106	10,132	9,209	9,739	11,903	21,284	34,528	228,616	37,274
4,745	4,352	4,246	4,359	5,305	7,302	10,206	79,042	10,579	8,657	7,884	6,124	5,462	4,766	4,370	4,264	4,377	5,325	7,327	10,242	79,378	10,622
303	253	252	286	334	544	787	5,914	904	749	649	478	390	304	254	253	287	335	546	790	5,939	908
526	608	754	750	764	768	730	7,811	621	578	557	577	565	523	604	750	747	760	764	726	7,771	618
23	27	30	27	29	34	33	322	27	24	23	24	22	22	26	30	27	29	34	33	320	27
5,595	5,239	5,281	5,422	6,433	8,648	11,755	93,089	12,131	10,008	9,114	7,203	6,440	5,615	5,254	5,296	5,438	6,450	8,671	11,790	93,409	12,174
6	4	3	5	7	17	23	140	25	19	12	11	8	6	4	3	5	7	17	23	140	25
2	2	2	2	3	3	4	33	4	4	2	2	3	2	2	2	2	3	3	4	33	4
257	425	429	413	323	423	448	4,299	372	334	367	197	313	257	425	429	413	323	423	448	4,299	372
265	431	434	420	333	443	475	4,472	401	357	381	210	324	265	431	434	420	333	443	475	4,472	401
13	12	11	14	17	12	14	150	10	11	14	14	15	14	13	13	16	19	13	16	168	12
234	226	233	266	284	274	264	2,999	252	253	258	271	269	251	242	250	284	303	293	282	3,209	265
38	32	37	36	33	31	33	432	40	37	45	46	45	42	36	41	40	37	35	37	481	44
285	270	281	316	334	317	312	3,581	302	301	317	331	329	308	291	303	340	359	341	335	3,857	321
17,187	16,019	15,158	15,846	18,949	30,605	46,915	328,539	49,920	39,627	32,852	25,403	21,061	17,294	16,109	15,242	15,936	19,045	30,738	47,128	330,354	50,170
1,863	1,891	2,037	1,999	2,227	2,337	2,458	26,161	2,614	2,261	2,287	2,123	2,007	1,853	1,881	2,026	1,989	2,216	2,325	2,446	26,028	2,601
8,824	11,611	13,996	13,520	10,681	9,894	9,701	122,703	9,862	8,324	8,927	8,469	8,644	8,775	11,547	13,918	13,445	10,622	9,840	9,647	122,019	9,808
217	286	344	332	263	243	239	3,017	242	205	220	208	213	216	284	342	331	261	242	237	3,000	241
10,904	13,788	16,376	15,851	13,170	12,474	12,397	151,881	12,718	10,790	11,434	10,800	10,864	10,844	13,712	16,286	15,764	13,099	12,407	12,331	151,048	12,650
44	44	46	43	42	39	42	508	41	39	44	42	43	44	44	46	43	42	39	42	508	41
10,948	13,832	16,423	15,894	13,212	12,513	12,439	152,389	12,759	10,828	11,478	10,842	10,906	10,888	13,756	16,333	15,807	13,141	12,446	12,373	151,556	12,691
165	169	168	169	214	333	433	3,305	444	370	346	271	221	165	169	168	169	214	333	433	3,305	444
10	8	8	8	13	30	41	253	47	36	26	15	13	11	8	8	8	13	30	42	258	48
3	3	3	4	4	5	7	54	7	5	5	4	4	3	3	3	4	4	5	7	54	7
4	3	3	4	6	11	16	98	20	11	9	7	5	4	3	3	4	6	11	16	98	20
3	2	2	2	4	6	7	59	9	7	8	5	4	3	2	2	2	4	6	7	59	9
2	2	2	2	3	6	10	66	12	11	7	5	3	2	2	2	2	3	6	10	66	12
187	188	186	189	243	391	513	3,834	539	440	401	308	250	188	188	186	189	243	392	514	3,839	540
1	0	0	0	1	2	3	16	3	2	2	2	1	1	0	0	0	1	2	3	16	3
188	188	186	189	244	393	516	3,850	542	442	403	310	251	188	188	186	189	244	394	517	3,855	543
295	406	422	441	371	400	418	4,231	251	281	377	375	207	297	412	430	445	375	405	422	4,276	255
366	305	314	347	742	1,940	2,183	11,383	1,736	1,460	846	647	542	368	310	321	350	750	1,963	2,202	11,494	1,763
661	711	736	788	1,112	2,340	2,601	15,614	1,986	1,741	1,223	1,022	749	665	722	751	794	1,125	2,368	2,624	15,770	2,018
28,984	30,750	32,502	32,716	33,517	45,851	62,472	500,392	65,206	52,638	45,955	37,577	32,968	29,034	30,775	32,512	32,727	33,555	45,946	62,642	501,535	65,422
79	84	89	90	92	126	171	1371	179	144	126	103	90	80	84	89	90	92	126	172	1374	179

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	TOTAL	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16
26,476	20,686	15,535	12,091	9,346	8,462	7,677	8,167	10,221	18,763	31,521	203,131	34,338	26,600	20,781	15,607	12,147	9,389	8,498	7,709	8,202	10,258
49	39	29	23	17	16	14	15	19	35	59	378	64	50	39	29	23	17	16	14	15	19
2,581	2,426	2,181	1,922	1,794	1,696	1,555	1,596	1,703	2,551	3,072	26,088	3,024	2,593	2,437	2,191	1,931	1,802	1,703	1,562	1,602	1,709
11	11	10	9	8	8	7	7	8	11	14	116	13	12	11	10	9	8	8	7	7	8
29,117	23,161	17,754	14,044	11,165	10,181	9,253	9,785	11,950	21,361	34,666	229,713	37,440	29,254	23,267	17,836	14,109	11,217	10,224	9,292	9,827	11,994
8,693	7,917	6,147	5,483	4,784	4,385	4,278	4,392	5,341	7,347	10,270	79,659	10,655	8,721	7,942	6,168	5,501	4,800	4,400	4,293	4,407	5,360
752	652	480	392	305	254	253	288	336	548	792	5,960	911	755	654	481	393	306	255	254	289	338
575	554	575	563	521	602	746	743	757	759	722	7,734	615	573	551	572	560	518	599	742	739	753
24	23	24	22	22	26	29	26	29	34	33	319	26	24	23	24	22	22	26	29	26	29
10,045	9,146	7,225	6,459	5,632	5,267	5,307	5,450	6,462	8,688	11,816	93,672	12,207	10,073	9,170	7,245	6,476	5,646	5,280	5,319	5,462	6,479
19	12	11	8	6	4	3	5	7	17	23	140	25	19	12	11	8	6	4	3	5	7
4	2	2	3	2	2	2	2	3	3	4	33	4	4	2	2	3	2	2	2	2	3
334	367	197	313	257	425	429	413	323	423	448	4,299	372	334	367	197	313	257	425	429	413	323
357	381	210	324	265	431	434	420	333	443	475	4,472	401	357	381	210	324	265	431	434	420	333
12	15	15	17	16	15	14	17	21	15	18	187	13	13	17	17	19	18	17	16	19	23
265	270	285	283	263	254	262	299	319	308	296	3,369	278	279	284	299	297	277	267	275	314	335
42	51	51	50	47	40	46	45	42	39	42	537	49	47	57	57	55	53	45	51	50	46
319	336	351	349	327	309	322	361	381	361	356	4,092	340	339	357	373	371	347	328	342	383	404
39,838	33,024	25,541	21,176	17,389	16,188	15,316	16,015	19,126	30,852	47,313	331,949	50,389	40,022	33,175	25,664	21,280	17,475	16,263	15,387	16,091	19,210
2,250	2,276	2,113	1,997	1,844	1,872	2,016	1,979	2,205	2,314	2,434	25,902	2,589	2,239	2,265	2,102	1,987	1,835	1,863	2,007	1,970	2,194
8,279	8,879	8,422	8,596	8,726	11,482	13,840	13,369	10,563	9,785	9,594	121,344	9,754	8,233	8,830	8,376	8,550	8,679	11,421	13,766	13,298	10,507
204	218	207	211	215	282	340	329	260	241	236	2,984	240	202	217	206	210	213	281	339	327	258
10,733	11,373	10,741	10,805	10,785	13,637	16,197	15,677	13,028	12,340	12,264	150,229	12,583	10,675	11,312	10,685	10,747	10,728	13,565	16,112	15,595	12,960
39	44	42	43	44	44	46	43	42	39	42	508	41	39	44	42	43	44	44	46	43	42
10,771	11,417	10,783	10,847	10,829	13,681	16,243	15,720	13,070	12,379	12,306	150,737	12,624	10,714	11,356	10,727	10,790	10,771	13,609	16,158	15,638	13,002
370	346	271	221	165	169	168	169	214	333	433	3,305	444	370	346	271	221	165	169	168	169	214
37	26	16	13	11	8	8	8	13	31	43	263	49	38	27	16	13	11	9	9	9	13
5	5	4	4	3	3	3	4	4	5	7	54	7	5	5	4	4	3	3	3	4	4
11	9	7	5	4	3	3	4	6	11	16	98	20	11	9	7	5	4	3	3	4	6
7	8	5	4	3	2	2	2	4	6	7	59	9	7	8	5	4	3	2	2	2	4
11	7	5	3	2	2	2	2	3	6	10	66	12	11	7	5	3	2	2	2	2	3
441	401	309	250	188	188	186	189	243	393	515	3,844	541	441	402	309	251	188	189	186	189	244
2	2	2	1	1	0	0	0	1	2	3	16	3	2	2	2	1	1	0	0	0	1
442	403	310	252	188	189	186	189	244	395	518	3,860	544	443	404	311	252	189	189	186	190	245
285	383	381	211	303	422	442	452	382	412	426	4,352	258	293	389	386	215	309	431	447	460	390
1,480	860	656	552	376	316	329	356	765	1,996	2,222	11,672	1,790	1,523	873	666	562	383	323	333	362	781
1,765	1,243	1,037	763	679	738	771	808	1,147	2,408	2,647	16,024	2,048	1,815	1,261	1,052	777	692	755	780	823	1,171
52,816	46,088	37,671	33,038	29,085	30,795	32,516	32,733	33,587	46,034	62,784	502,570	65,604	52,994	46,196	37,753	33,099	29,127	30,815	32,512	32,741	33,627
145	126	103	91	80	84	89	90	92	126	172	1377	180	145	127	103	91	80	84	89	90	92

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

PACIFIC GAS ANI
GAS DEI

Nov-16	Dec-16	TOTAL	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
18,826	31,637	203,991	34,482	26,718	20,870	15,674	12,200	9,430	8,531	7,740	8,235	10,293	18,886	31,747	204,807	34,618	26,829	20,954	15,737	12,248	9,467
35	59	380	64	50	39	29	23	18	16	14	15	19	35	59	381	64	50	39	29	23	18
2,560	3,084	26,198	3,037	2,604	2,447	2,200	1,940	1,810	1,710	1,568	1,609	1,715	2,568	3,094	26,303	3,049	2,615	2,457	2,209	1,947	1,817
11	14	116	13	12	11	10	9	8	8	7	7	8	11	14	117	14	12	11	10	9	8
21,432	34,793	230,686	37,597	29,384	23,367	17,913	14,171	11,265	10,265	9,330	9,866	12,036	21,500	34,914	231,608	37,745	29,506	23,461	17,985	14,227	11,310
7,371	10,306	79,924	10,697	8,757	7,973	6,192	5,523	4,818	4,416	4,309	4,424	5,378	7,394	10,339	80,220	10,730	8,785	7,998	6,211	5,540	4,833
549	795	5,980	914	758	657	483	394	307	256	255	290	339	551	797	6,002	917	760	659	485	396	308
756	718	7,696	612	570	549	569	557	516	596	739	736	749	751	714	7,658	609	567	546	566	555	513
34	32	317	26	24	23	24	21	22	26	29	26	29	33	32	316	26	23	23	24	21	22
8,710	11,851	93,918	12,249	10,108	9,201	7,268	6,496	5,664	5,294	5,332	5,476	6,494	8,730	11,883	94,196	12,282	10,136	9,225	7,286	6,512	5,677
17	23	140	25	19	12	11	8	6	4	3	5	7	17	23	140	25	19	12	11	8	6
3	4	33	4	4	2	2	3	2	2	2	2	3	3	4	33	4	4	2	2	3	2
423	448	4,299	372	334	367	197	313	257	425	429	413	323	423	448	4,299	372	334	367	197	313	257
443	475	4,472	401	357	381	210	324	265	431	434	420	333	443	475	4,472	401	357	381	210	324	265
17	20	208	14	15	19	19	21	20	18	18	22	26	18	22	232	55	52	63	63	62	59
323	311	3,537	292	293	298	314	312	290	280	289	329	351	339	327	3,714	306	307	313	330	327	305
43	46	598	55	52	63	63	62	59	50	57	56	52	48	52	667	55	52	63	63	62	59
383	377	4,344	361	359	380	397	394	369	348	363	407	429	406	401	4,614	416	411	439	456	451	422
30,968	47,496	333,420	50,609	40,208	33,329	25,788	21,385	17,563	16,338	15,459	16,168	19,291	31,079	47,672	334,889	50,845	40,410	33,506	25,937	21,514	17,674
2,303	2,422	25,778	2,576	2,228	2,254	2,092	1,978	1,826	1,854	1,997	1,960	2,184	2,292	2,410	25,650	2,562	2,217	2,243	2,081	1,967	1,817
9,733	9,543	120,691	9,699	8,187	8,780	8,330	8,503	8,631	11,357	13,690	13,224	10,449	9,679	9,490	120,019	9,644	8,141	8,731	8,282	8,453	8,581
239	235	2,968	238	201	216	205	209	212	279	337	325	257	238	233	2,951	237	200	215	204	208	211
12,275	12,200	149,437	12,513	10,616	11,250	10,627	10,689	10,670	13,491	16,023	15,509	12,890	12,209	12,134	148,621	12,444	10,558	11,188	10,566	10,628	10,609
39	42	508	41	39	44	42	43	44	44	46	43	42	39	42	508	41	39	44	42	43	44
12,314	12,242	149,945	12,554	10,655	11,294	10,669	10,732	10,713	13,535	16,069	15,552	12,932	12,248	12,176	149,129	12,485	10,596	11,232	10,608	10,671	10,652
333	433	3,305	444	370	346	271	221	165	169	168	169	214	333	433	3,305	444	370	346	271	221	165
32	44	268	50	39	27	16	14	11	9	9	9	14	32	45	273	51	39	28	16	14	11
5	7	54	7	5	5	4	4	3	3	3	4	4	5	7	54	7	5	5	4	4	3
11	16	98	20	11	9	7	5	4	3	3	4	6	11	16	98	20	11	9	7	5	4
6	7	59	9	7	8	5	4	3	2	2	2	4	6	7	59	9	7	8	5	4	3
6	10	66	12	11	7	5	3	2	2	2	2	3	6	10	66	12	11	7	5	3	2
393	516	3,849	542	442	403	309	251	188	189	187	190	244	394	517	3,855	543	443	403	310	251	188
2	3	16	3	2	2	2	1	1	0	0	0	1	2	3	16	3	2	2	2	1	1
395	519	3,865	545	444	405	311	252	189	189	187	190	245	396	520	3,870	546	445	405	311	252	189
419	432	4,429	262	301	395	392	219	315	441	453	469	399	426	439	4,510	267	310	401	398	223	322
2,029	2,256	11,881	1,818	1,566	886	676	573	391	331	337	369	798	2,064	2,293	12,101	1,848	1,614	900	686	584	399
2,448	2,689	16,310	2,080	1,868	1,280	1,068	791	706	772	790	838	1,196	2,490	2,733	16,611	2,114	1,925	1,301	1,085	808	721
46,125	62,945	503,540	65,787	53,175	46,307	37,835	33,161	29,171	30,834	32,505	32,748	33,664	46,213	63,100	504,500	65,990	53,375	46,443	37,941	33,245	29,236
126	172	1380	180	146	127	104	91	80	84	89	90	92	127	173	1382	181	146	127	104	91	80

D ELECTRIC COMPANY
MAND FORECAST
(MDTH)

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	TOTAL	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	TOTAL	Jan-20	Feb-20
8,563	7,769	8,265	10,326	18,940	31,848	205,563	34,741	26,930	21,031	15,794	12,293	9,502	8,591	7,795	8,292	10,356	18,990	31,940	206,256	35,218	27,320
16	14	15	19	35	59	383	65	50	39	29	23	18	16	15	15	19	35	59	384	66	51
1,716	1,574	1,615	1,721	2,575	3,104	26,399	3,060	2,625	2,466	2,217	1,955	1,824	1,722	1,579	1,620	1,726	2,582	3,113	26,488	3,102	2,663
8	7	7	8	11	14	117	14	12	11	10	9	8	8	7	7	8	11	14	118	14	12
10,302	9,364	9,902	12,074	21,562	35,025	232,462	37,880	29,617	23,547	18,051	14,280	11,352	10,337	9,395	9,935	12,108	21,619	35,126	233,246	38,399	30,046
4,429	4,321	4,436	5,392	7,412	10,364	80,451	10,759	8,810	8,020	6,227	5,554	4,845	4,439	4,331	4,446	5,403	7,426	10,385	80,646	10,643	8,711
257	256	291	340	552	799	6,020	919	762	661	486	397	309	258	257	292	340	554	801	6,034	909	754
593	735	732	745	747	711	7,619	606	564	543	563	552	510	589	731	728	741	743	706	7,577	604	563
26	29	26	28	33	32	314	26	23	23	24	21	22	26	29	26	28	33	32	312	26	23
5,304	5,341	5,485	6,505	8,745	11,905	94,404	12,310	10,160	9,246	7,300	6,524	5,687	5,312	5,347	5,492	6,512	8,756	11,923	94,569	12,183	10,050
4	3	5	7	17	23	140	25	19	12	11	8	6	4	3	5	7	17	23	140	25	19
2	2	2	3	3	4	33	4	4	2	2	3	2	2	2	2	3	3	4	33	4	4
425	429	413	323	423	448	4,299	372	334	367	197	313	257	425	429	413	323	423	448	4,299	372	334
431	434	420	333	443	475	4,472	401	357	381	210	324	265	431	434	420	333	443	475	4,472	401	357
50	57	56	52	48	52	667	55	52	63	63	62	59	50	57	56	52	48	52	667	55	52
294	303	346	369	356	343	3,900	322	323	329	346	344	320	309	319	363	387	374	360	4,095	338	339
50	57	56	52	48	52	667	55	52	63	63	62	59	50	57	56	52	48	52	667	55	52
394	417	457	472	452	446	5,234	432	426	455	473	467	437	408	432	475	491	470	464	5,429	448	443
16,431	15,556	16,264	19,383	31,202	47,851	336,572	51,023	40,560	33,628	26,033	21,595	17,741	16,488	15,609	16,321	19,444	31,288	47,987	337,717	51,431	40,895
1,845	1,987	1,950	2,172	2,280	2,398	25,519	2,549	2,205	2,230	2,070	1,957	1,807	1,834	1,976	1,939	2,160	2,267	2,384	25,377	2,506	2,168
11,293	13,612	13,149	10,388	9,623	9,435	119,331	9,586	8,091	8,677	8,231	8,402	8,529	11,221	13,525	13,065	10,320	9,560	9,373	118,580	9,854	8,318
278	335	323	255	237	232	2,934	236	199	213	202	207	210	276	333	321	254	235	230	2,916	242	205
13,415	15,933	15,422	12,816	12,139	12,065	147,784	12,370	10,495	11,121	10,504	10,565	10,546	13,331	15,833	15,325	12,734	12,062	11,988	146,873	12,603	10,690
44	46	43	42	39	42	508	41	39	44	42	43	44	44	46	43	42	39	42	508	41	39
13,459	15,980	15,465	12,858	12,178	12,107	148,292	12,411	10,534	11,165	10,545	10,608	10,589	13,375	15,879	15,368	12,776	12,101	12,030	147,381	12,644	10,729
169	168	169	214	333	433	3,305	444	370	346	271	221	165	169	168	169	214	333	433	3,305	444	370
9	9	9	14	33	46	279	52	40	28	17	14	12	9	9	9	14	34	47	284	53	41
3	3	4	4	5	7	54	7	5	5	4	4	3	3	3	4	4	5	7	54	7	5
3	3	4	6	11	16	98	20	11	9	7	5	4	3	3	4	6	11	16	98	20	11
2	2	2	4	6	7	59	9	7	8	5	4	3	2	2	2	4	6	7	59	9	7
2	2	2	3	6	10	66	12	11	7	5	3	2	2	2	2	3	6	10	66	12	11
189	187	190	244	394	518	3,860	544	444	404	310	251	189	189	187	190	245	395	519	3,866	545	445
0	0	0	1	2	3	16	3	2	2	2	1	1	0	0	0	1	2	3	16	3	2
189	187	190	245	396	520	3,876	547	445	406	311	253	189	189	187	190	246	397	521	3,882	548	446
452	459	479	408	433	447	4,598	271	320	407	404	228	328	463	464	489	417	441	455	4,688	278	333
339	342	377	816	2,102	2,332	12,338	1,878	1,666	914	697	596	407	347	346	385	834	2,140	2,373	12,584	1,922	1,731
790	800	856	1,223	2,535	2,779	16,936	2,150	1,986	1,321	1,101	825	736	810	810	873	1,251	2,581	2,827	17,272	2,199	2,064
30,870	32,522	32,775	33,709	46,312	63,258	505,677	66,130	53,525	46,520	37,991	33,280	29,255	30,862	32,485	32,753	33,716	46,367	63,366	506,251	66,822	54,135
85	89	90	92	127	173	1385	181	147	127	104	91	80	85	89	90	92	127	174	1387	183	148

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEMAND FORECAST
(MDTH)

Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	TOTAL
21,326	16,016	12,467	9,635	8,702	7,895	8,399	10,471	19,183	32,296	208,928
40	30	23	18	16	15	16	19	36	60	389
2,501	2,248	1,982	1,849	1,744	1,599	1,641	1,745	2,608	3,148	26,830
11	10	9	8	8	7	7	8	12	14	119
23,877	18,304	14,481	11,511	10,470	9,516	10,063	12,243	21,839	35,518	236,266
7,932	6,159	5,493	4,793	4,393	4,286	4,400	5,351	7,361	10,289	79,810
653	481	392	306	255	254	289	337	549	793	5,972
542	562	550	509	588	730	727	740	743	706	7,564
23	23	21	22	26	29	26	28	33	32	312
9,150	7,225	6,457	5,630	5,262	5,299	5,441	6,456	8,685	11,820	93,658
12	11	8	6	4	3	5	7	17	23	140
2	2	3	2	2	2	2	3	3	4	33
367	197	313	257	425	429	413	323	423	448	4,299
381	210	324	265	431	434	420	333	443	475	4,472
63	63	62	59	50	57	56	52	48	52	667
345	364	361	336	324	334	381	407	393	378	4,300
63	63	62	59	50	57	56	52	48	52	667
471	490	484	453	424	448	493	510	489	482	5,634
33,879	26,228	21,746	17,859	16,587	15,697	16,417	19,542	31,456	48,294	340,031
2,193	2,035	1,924	1,777	1,803	1,942	1,906	2,123	2,228	2,344	24,950
8,921	8,460	8,635	8,766	11,530	13,898	13,426	10,604	9,823	9,631	121,866
219	208	212	216	284	342	330	261	242	237	2,997
11,333	10,703	10,772	10,758	13,617	16,182	15,662	12,988	12,293	12,211	149,812
44	42	43	44	44	46	43	42	39	42	508
11,377	10,745	10,814	10,802	13,661	16,228	15,705	13,030	12,332	12,253	150,320
346	271	221	165	169	168	169	214	333	433	3,305
29	17	15	12	9	9	9	15	34	47	290
5	4	4	3	3	3	4	4	5	7	54
9	7	5	4	3	3	4	6	11	16	98
8	5	4	3	2	2	2	4	6	7	59
7	5	3	2	2	2	2	3	6	10	66
404	310	252	189	189	187	190	245	396	520	3,871
2	2	1	1	0	0	0	1	2	3	16
406	312	253	189	189	187	190	246	398	522	3,887
416	414	234	338	477	473	503	429	452	465	4,812
934	713	613	419	358	353	396	859	2,192	2,428	12,918
1,350	1,127	848	757	835	826	898	1,288	2,644	2,894	17,730
47,013	38,412	33,662	29,607	31,273	32,938	33,211	34,105	46,829	63,963	511,969
129	105	92	81	86	90	91	93	128	175	1403

Table 44 NR Annual Forecast – Average Demand Year

ANNUAL GAS SUPPLY
FORECAST YEARS 2004-2008
MMCF/DAY

AVERAGE DEMAND YEAR

LINE		2006	2007	2008	2009	2010	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path(1)	1140	1140	1140	1140	1140	2
3	Redwood Path(2)	2021	2021	2021	2021	2021	3
4	**Supplemental(3)**	0	0	0	0	0	4
5	**Total Supplies Available**	3291	3291	3291	3291	3291	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	1973	2036	2030	2069	2114	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2103	2166	2160	2199	2244	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2103	2166	2160	2199	2244	11
	REQUIREMENTS FORECAST BY END USE						
	CORE						
12	Residential	554	574	586	596	602	12
13	Commercial	230	237	242	245	247	13
14	NGV	5	4	6	7	8	14
15	**Total Core**	789	815	834	848	857	15
	NONCORE						
16	Industrial	410	412	414	417	416	16
17	SMUD Electric Generation(4)	95	108	112	116	125	17
18	PG&E Electric Generation(5)	634	654	617	633	660	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
21	Southwest Exchange Gas(6)	0	0	7	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1151	1186	1162	1187	1222	23
24	**Off-System Deliveries(7)**	124	124	124	124	124	24
	Shrinkage						
25	Company use and Unaccounted for	39	40	40	41	41	25
26	**TOTAL END USE**	2103	2166	2160	2199	2244	26
27	System Curtailment	0	0	0	0	0	27

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission N
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Forecast by PG&E, not by SMUD.
(5) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connectec system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system. Forecast for 2006 ref current hydro conditions.
(6) SoCal Gas's agreement to deliver gas to Southwest Gas expires in April 2008. It is assumed that PG&E will serve Sou demand after this point.
(7) Deliveries to southern California.

ANNUAL GAS SUPPLY
FORECAST YEARS 2010-2025
MMCF/DAY

AVERAGE DEMAND YEAR

LINE		2011	2012	2015	2020	2025	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path(1)	1140	1140	1140	1140	1140	2
3	Redwood Path(2)	2021	2021	2021	2021	2021	3
4	**Supplemental(3)**	0	0	0	0	0	4
5	**Total Supplies Available**	3291	3291	3291	3291	3291	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	2161	2168	2136	2339	2508	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2291	2298	2266	2469	2638	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2291	2298	2266	2469	2638	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential	607	609	621	632	643	12
13	Commercial	249	250	253	256	259	13
14	NGV	8	9	11	15	20	14
15	**Total Core**	864	868	885	903	922	15
	Noncore						
16	Industrial	414	411	406	404	402	16
17	SMUD Electric Generation(4)	139	144	188	247	308	17
18	PG&E Electric Generation(5)	686	688	600	724	811	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
21	Southwest Exchange Gas(6)	9	9	9	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1260	1264	1215	1396	1542	23
24	**Off-System Deliveries(7)**	124	124	124	124	124	24
	Shrinkage						
25	Company use and Unaccounted for	42	42	42	46	50	25
26	**TOTAL END USE**	2291	2298	2266	2469	2638	26
27	System Curtailment	0	0	0	0	0	27

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission N
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Forecast by PG&E, not by SMUD.
(5) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connectec system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system.
(6) SoCal Gas's agreement to deliver gas to Southwest Gas expires in April 2008. It is assumed that PG&E will serve So demand after this point.
(7) Deliveries to southern California.

Table 45 NR Annual Forecast – High Demand Year

ANNUAL GAS SUPPLY
FORECAST YEARS 2004-2008
MMCF/DAY

HIGH DEMAND YEAR

LINE		2006	2007	2008	2009	2010	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path(1)	1140	1140	1140	1140	1140	2
3	Redwood Path(2)	2021	2021	2021	2021	2021	3
4	**Supplemental(3)**	0	0	0	0	0	4
5	**Total Supplies Available**	3291	3291	3291	3291	3291	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	1986	2304	2295	2330	2379	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2116	2434	2425	2460	2509	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2116	2434	2425	2460	2509	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential	563	584	597	609	616	12
13	Commercial	233	241	245	249	251	13
14	NGV	5	4	6	7	8	14
15	**Total Core**	801	829	848	865	875	15
	Noncore						
16	Industrial	410	412	414	417	416	16
17	SMUD Electric Generation(4)	95	123	131	137	146	17
18	PG&E Electric Generation(5)	634	890	843	851	880	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
21	Southwest Exchange Gas(6)	0	0	7	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,151	1,436	1,408	1,426	1,464	23
24	**Off-System Deliveries(7)**	124	124	124	124	124	24
	Shrinkage						
25	Company use and Unaccounted for	40	45	45	45	46	25
26	**TOTAL END USE**	2116	2434	2425	2460	2509	26
27	System Curtailment	0	0	0	0	0	27

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.

(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission N

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Forecast by PG&E, not by SMUD.

(5) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connectec system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system. Forecast for 2006 ref current hydro conditions.

(6) SoCal Gas's agreement to deliver gas to Southwest Gas expires in April 2008. It is assumed that PG&E will serve Sou demand after this point.

(7) Deliveries to southern California.

ANNUAL GAS SUPPLY
FORECAST YEARS 2010-2025
MMCF/DAY

HIGH DEMAND YEAR

LINE		2011	2012	2015	2020	2025	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path(1)	1140	1140	1140	1140	1140	2
3	Redwood Path(2)	2021	2021	2021	2021	2021	3
4	**Supplemental(3)**	0	0	0	0	0	4
5	**Total Supplies Available**	3291	3291	3291	3291	3291	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	2444	2454	2430	2650	2832	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2574	2584	2560	2780	2962	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2574	2584	2560	2780	2962	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential	622	627	645	670	692	12
13	Commercial	253	253	257	257	260	13
14	NGV	8	9	11	15	20	14
15	**Total Core**	883	889	913	942	972	15
	Noncore						
16	Industrial	414	411	406	404	402	16
17	SMUD Electric Generation(4)	166	173	230	283	342	17
18	PG&E Electric Generation(5)	918	918	818	954	1,045	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
21	Southwest Exchange Gas(6)	9	9	9	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1519	1523	1475	1662	1810	23
24	**Off-System Deliveries(7)**	124	124	124	124	124	24
	Shrinkage						
25	Company use and Unaccounted for	48	48	48	52	56	25
26	**TOTAL END USE**	2574	2584	2560	2780	2962	26
27	System Curtailment	0	0	0	0	0	27

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission N
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Forecast by PG&E, not by SMUD.
(5) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system.
(6) SoCal Gas's agreement to deliver gas to Southwest Gas expires in April 2008. It is assumed that PG&E will serve So demand after this point.
(7) Deliveries to southern California.

7.2. Southern California Region

Historical Raw Data Tables

Table 46 SR Historical Raw Data

South Region Gas Deliveries 2002

	Monthly Average Deliveries (MMcf/Day)				***Storage Usage*** SoCalGas Storage		
Month	**Core**	**NC**	**Total Sendout**	**NC Sub-Total Whsale/ Rtl EG & UEG**	**Withdrawals**	**Injection**	**Net Inj/Wd**
January							
February							
March							
April	1015	1508	2523	465	38	411	374
May	876	1494	2370	514	53	423	369
June	771	1897	2668	926	98	304	207
July	704	2257	2961	1289	100	348	248
August	708	2083	2791	1135	117	146	29
September	740	1878	2617	929	128	170	42
October	880	1493	2373	502	58	263	205
November	1049	1404	2453	425	70	229	159
December	1606	1512	3119	454	897	9	-888

South Region Gas Deliveries 2005

	Monthly Average Deliveries (MMcf/ Day)				***Storage Usage*** *SoCalGas Storage*		
Month	**Core**	**NC**	**Total Sendout**	**NC Sub-Total Whsale/ Rtl EG & UEG**	**Withdrawals**	**Injection**	**Net Inj/Wd**
January	1537	1574	3111	456	719	33	-685
February	1409	1498	2907	467	590	4	-586
March	1187	1427	2614	434	243	140	-103
April	1015	1358	2373	405	43	463	420
May	827	1411	2239	499	57	614	557
June	836	1303	2138	437	75	499	424
July	718	1732	2450	865	123	305	181
August	738	1648	2385	816	153	130	-24
September	810	1275	2084	411	68	233	165
October	825	1263	2088	355	38	394	356
November	1095	1286	2381	395	99	98	0
December	1386	1431	2817	446	631	100	-531

South Region Gas Deliveries 2003

Month	*Monthly Average Deliveries (MMcf/Day)*				*Storage Usage* SoCalGas Storage		
	Core	NC	Total Sendout	NC Sub-Total Whsale/ Rtl EG & UEG	Withdrawals	Injection	Net Inj/Wd
January	1189	1584	2773	545	585	24	-561
February	1376	1642	3018	585	1073	16	-1056
March	1180	1545	2725	518	317	131	-186
April	1116	1403	2519	395	108	227	119
May	906	1300	2207	367	27	533	505
June	849	1340	2189	471	42	679	637
July	746	1892	2637	1038	78	321	243
August	711	1849	2561	983	84	283	199
September	779	1661	2440	804	37	473	436
October	881	1509	2390	637	57	463	406
November	1362	1329	2691	384	161	155	-6
December	1675	1540	3215	455	676	38	-638

South Region Gas Deliveries 2006

Month	Monthly Average Deliveries (MMcf/Day)				Storage Usage SoCalGas Storage		
	Core	NC	Total Sendout	NC Sub-Total Whsale/ Rtl EG & UEG	Withdrawals	Injection	Net Inj/Wd
January	1532	1459	2992	418	418	43	-374
February	1353	1474	2827	472	537	22	-515
March	1588	1461	3048	442	558	15	-543
April	1182	1448	2630	545	89	330	242
May	879	1375	2254	499	43	522	480
June	798	1597	2395	729	50	348	299
July	749	2152	2901	1303	225	277	52
August	688	1654	2342	742	99	305	207
September	755	1582	2337	693	64	467	403
October	838	1423	2261	489	50	361	311
November	1119	1390	2508	514	215	153	-62
December	1689	1481	3171	508	692	39	-653

South Region Gas Deliveries 2007

Month	*Monthly Average Deliveries (MMcf/ Day)* Core	NC	Total Sendout	NC Sub-Total Whsale/ Rtl EG & UEG	*Storage Usage* *SoCalGas Storage* Withdrawals	Injection	Net Inj/Wd
January	1947	1480	3427	424	1199	26	-1173
February	1504	1396	2899	387	553	48	-505
March	1117	1326	2443	321	63	295	231
April							
May							
June							
July							
August							
September							
October							
November							
December							

South Region Gas Deliveries 2004

Month	*Monthly Average Deliveries (MMcf/Day)* Core	NC	Total Sendout	NC Sub-Total Whsale/ Rtl EG & UEG	***Storage Usage*** *SoCalGas Storage* Withdrawals	Injection	Net Inj/Wd
January	1599	1446	3045	372	927	1	-926
February	1689	1499	3188	445	892	9	-883
March	1027	1514	2540	558	141	174	34
April	1045	1427	2472	525	11	382	371
May	851	1459	2310	572	16	622	606
June	813	1448	2260	548	35	675	640
July	797	1769	2566	888	105	359	255
August	777	1793	2570	919	49	368	319
September	718	1863	2581	937	90	395	305
October	865	1612	2477	702	93	332	239
November	1458	1566	3024	630	286	90	-196
December	1578	1668	3246	575	495	54	-440

Forecast Data Table

Table 47 SR Monthly Forecast Data – Average Temperature Year

Work Paper: TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2007

AVERAGE TEMPERATURE YEAR

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg	L
FIRM CAPACITY AVAILABLE															
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310	
Out-of-State Gas															
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50	
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540	
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800	
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765	
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200	
LNG Capacity 3/		0	0	0	0	0	0	0	0	0	0	0	0	0	
Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	3,565	3,565	3,565	3,565	3,565	3,565	3,565	3,565	
TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	
GAS SUPPLY TAKEN															
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310	
Out-of-State		2,931	2,809	2,530	2,211	1,954	1,965	2,087	2,137	2,105	1,953	2,462	2,999	2,343	
TOTAL SUPPLY TAKEN		3,241	3,119	2,840	2,521	2,264	2,275	2,397	2,447	2,415	2,263	2,772	3,309	2,653	
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0	
TOTAL THROUGHPUT 1/		3,241	3,119	2,840	2,521	2,264	2,275	2,397	2,447	2,415	2,263	2,772	3,309	2,653	
REQUIREMENTS FORECAST BY END-USE 2/															
CORE	Residential	1,174	1,067	898	698	519	419	378	378	387	461	810	1,207	698	
	Commercial	278	286	229	210	195	186	164	162	177	173	247	286	216	
	Industrial	67	71	65	63	59	60	54	56	61	59	65	66	62	
	NGV	19	20	21	21	21	21	21	21	22	21	21	21	21	
	Subtotal-CORE	1,539	1,445	1,212	992	794	686	617	618	648	713	1,143	1,579	997	
NONCORE	Commercial	70	67	62	59	51	50	46	47	56	53	56	65	57	
	Industrial	336	342	341	340	330	340	341	362	364	350	346	336	344	
	EOR Steaming	35	35	35	35	35	35	35	35	35	35	35	35	35	
	Electric Generation (EG)	704	695	712	685	682	797	974	987	916	731	724	730	779	
	Subtotal-NONCORE	1,145	1,139	1,149	1,119	1,098	1,222	1,395	1,432	1,371	1,169	1,161	1,166	1,214	
WHOLESALE &	Core	291	271	233	184	144	120	112	108	113	131	197	278	181	
INTERNATIONAL	Noncore Excl. EG	44	42	42	41	39	44	44	44	48	44	48	41	43	
	Electric Generation (EG)	162	163	151	138	146	160	184	199	190	164	171	181	168	
	Subtotal-WHOLESALE & INTL	497	476	426	363	329	324	340	352	351	339	416	501	392	
	Co. Use & LUAF	61	59	53	47	43	43	45	46	45	43	52	62	50	
SYSTEM TOTAL THROUGHPUT		3,241	3,119	2,840	2,521	2,264	2,275	2,397	2,447	2,415	2,263	2,772	3,309	2,653	
TRANSPORTATION AND EXCHANGE															
CORE	All End Uses	11	11	9	8	6	6	5	5	5	6	9	11	8	
NONCORE	Commercial/Industrial	406	409	402	399	381	390	387	410	420	404	402	402	401	
	EOR Steaming	35	35	35	35	35	35	35	35	35	35	35	35	35	
	Electric Generation (EG)	704	695	712	685	682	797	974	987	916	731	724	730	779	
	Subtotal-RETAIL	1,156	1,150	1,158	1,127	1,104	1,228	1,400	1,436	1,376	1,175	1,170	1,178	1,222	
WHOLESALE & INTERNATIONAL	All End Uses	497	476	426	363	329	324	340	352	351	339	416	501	392	
TOTAL TRANSPORTATION & EXCHANGE		1,653	1,626	1,584	1,490	1,433	1,551	1,740	1,788	1,727	1,513	1,586	1,679	1,614	
CURTAILMENT (RETAIL & WHOLESALE)															
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0	
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0	
NOTES:															
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach		3	3	3	3	3	3	3	3	3	3	3	3	3	

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes

3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2008

AVERAGE TEMPERATURE YEAR

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
FIRM CAPACITY AVAILABLE														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State Gas														
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200
LNG Capacity 3/		800	800	800	800	800	800	800	800	800	800	800	800	800
Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365
TOTAL CAPACITY AVAILABLE		4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675
GAS SUPPLY TAKEN														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State		2,950	2,758	2,556	2,239	1,977	2,039	2,165	2,239	2,159	2,070	2,568	3,079	2,400
TOTAL SUPPLY TAKEN		3,260	3,068	2,866	2,549	2,287	2,349	2,475	2,549	2,469	2,380	2,878	3,389	2,710
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL THROUGHPUT 1/		3,260	3,068	2,866	2,549	2,287	2,349	2,475	2,549	2,469	2,380	2,878	3,389	2,710
REQUIREMENTS FORECAST BY END-USE 2/														
CORE	Residential	1,183	1,038	904	703	523	422	381	381	390	465	816	1,216	701
	Commercial	278	276	229	209	194	186	164	161	177	172	246	285	215
	Industrial	66	68	64	62	58	59	53	56	61	58	65	65	61
	NGV	20	21	22	23	22	23	22	23	24	22	23	22	22
	Subtotal-CORE	1,547	1,403	1,219	997	798	689	620	621	651	717	1,149	1,588	999
NONCORE	Commercial	71	65	62	60	52	50	46	48	57	54	57	66	57
	Industrial	336	336	340	339	330	341	341	362	364	351	346	336	343
	EOR Steaming	35	35	35	35	35	35	27	27	27	27	20	20	30
	Electric Generation (EG)	709	689	721	705	695	858	1,045	1,080	973	845	832	831	833
	Subtotal-NONCORE	1,150	1,125	1,158	1,139	1,112	1,283	1,459	1,517	1,420	1,276	1,254	1,252	1,263
WHOLESALE & INTERNATIONAL	Core	277	267	231	182	144	121	113	110	111	124	188	263	177
	Noncore Excl. EG	42	44	42	41	40	48	47	48	50	40	46	41	44
	Electric Generation (EG)	183	172	161	142	151	164	189	206	190	179	185	180	175
	Subtotal-WHOLESALE & INTL	501	482	434	365	335	332	349	363	352	342	420	485	397
	Co. Use & LUAF	61	58	54	48	43	44	47	48	46	45	54	64	51
SYSTEM TOTAL THROUGHPUT		3,260	3,068	2,866	2,549	2,287	2,349	2,475	2,549	2,469	2,380	2,878	3,389	2,710
TRANSPORTATION AND EXCHANGE														
CORE	All End Uses	11	10	9	8	6	6	5	5	5	6	9	11	8
NONCORE	Commercial/Industrial	406	401	402	399	382	391	388	410	421	404	403	402	401
	EOR Steaming	35	35	35	35	35	35	27	27	27	27	20	20	30
	Electric Generation (EG)	709	689	721	705	695	858	1,045	1,080	973	845	832	831	833
	Subtotal-RETAIL	1,161	1,135	1,167	1,146	1,118	1,289	1,464	1,522	1,426	1,281	1,263	1,264	1,270
WHOLESALE & INTERNATIONAL	All End Uses	501	482	434	365	335	332	349	363	352	342	420	485	397
TOTAL TRANSPORTATION & EXCHANGE		1,662	1,618	1,602	1,511	1,453	1,621	1,813	1,885	1,777	1,624	1,683	1,748	1,667
CURTAILMENT (RETAIL & WHOLESALE)														
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0

NOTES:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	3	3	3	3	3	3	3	3	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes

3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2009

AVERAGE TEMPERATURE YEAR

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
FIRM CAPACITY AVAILABLE														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State Gas														
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200
LNG Capacity 3/		800	800	800	800	800	800	800	800	800	800	800	800	800
Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365
TOTAL CAPACITY AVAILABLE		4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675
GAS SUPPLY TAKEN														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State		2,920	2,829	2,514	2,202	1,938	1,889	1,985	2,047	1,998	1,936	2,439	2,969	2,303
TOTAL SUPPLY TAKEN		3,230	3,139	2,824	2,512	2,248	2,199	2,295	2,357	2,308	2,246	2,749	3,279	2,613
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL THROUGHPUT 1/		3,230	3,139	2,824	2,512	2,248	2,199	2,295	2,357	2,308	2,246	2,749	3,279	2,613
REQUIREMENTS FORECAST BY END-USE 2/														
CORE	Residential	1,191	1,083	911	708	527	425	384	384	393	468	821	1,225	708
	Commercial	278	286	229	209	194	186	164	161	177	172	246	285	215
	Industrial	66	69	63	61	58	58	53	55	60	57	64	64	61
	NGV	21	23	23	24	23	24	23	24	25	23	24	23	23
	Subtotal-CORE	1,556	1,461	1,226	1,003	802	693	623	624	654	720	1,156	1,598	1,007
NONCORE	Commercial	71	68	63	60	52	51	47	48	57	54	57	67	58
	Industrial	335	342	340	340	331	341	342	363	365	351	346	336	344
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	710	704	688	667	661	699	852	870	792	690	676	683	725
	Subtotal-NONCORE	1,137	1,133	1,110	1,086	1,064	1,111	1,260	1,301	1,233	1,115	1,099	1,105	1,146
WHOLESALE & INTERNATIONAL	Core	265	263	221	174	138	117	110	108	111	124	189	265	173
	Noncore Excl. EG	41	44	42	41	40	48	47	48	51	41	47	41	44
	Electric Generation (EG)	171	178	171	161	162	190	211	233	214	204	205	208	192
	Subtotal-WHOLESALE & INTL	477	485	435	375	340	355	368	389	377	369	442	514	410
	Co. Use & LUAF	61	59	53	47	42	41	43	44	43	42	52	62	49
SYSTEM TOTAL THROUGHPUT		3,230	3,139	2,824	2,512	2,248	2,199	2,295	2,357	2,308	2,246	2,749	3,279	2,613
TRANSPORTATION AND EXCHANGE														
CORE	All End Uses	11	11	9	8	6	6	5	5	5	6	9	11	8
NONCORE	Commercial/Industrial	407	409	403	400	383	392	389	411	422	405	404	403	402
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	710	704	688	667	661	699	852	870	792	690	676	683	725
	Subtotal-RETAIL	1,148	1,144	1,119	1,094	1,070	1,116	1,265	1,306	1,239	1,121	1,108	1,117	1,154
WHOLESALE & INTERNATIONAL	All End Uses	477	485	435	375	340	355	368	389	377	369	442	514	410
TOTAL TRANSPORTATION & EXCHANGE		1,624	1,629	1,554	1,469	1,410	1,471	1,633	1,694	1,615	1,490	1,550	1,631	1,564
CURTAILMENT (RETAIL & WHOLESALE)														
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0

NOTES:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	3	3	3	3	3	3	3	3	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes
3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2010

AVERAGE TEMPERATURE YEAR

FIRM CAPACITY AVAILABLE		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State Gas														
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200
LNG Capacity 3/		800	800	800	800	800	800	800	800	800	800	800	800	800
Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365
TOTAL CAPACITY AVAILABLE		4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675
GAS SUPPLY TAKEN														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State		2,847	2,733	2,440	2,111	1,853	1,815	1,914	1,973	1,925	1,890	2,388	2,916	2,232
TOTAL SUPPLY TAKEN		3,157	3,043	2,750	2,421	2,163	2,125	2,224	2,283	2,235	2,200	2,698	3,226	2,542
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL THROUGHPUT 1/		3,157	3,043	2,750	2,421	2,163	2,125	2,224	2,283	2,235	2,200	2,698	3,226	2,542
REQUIREMENTS FORECAST BY END-USE 2/														
CORE	Residential	1,196	1,087	914	711	529	426	385	385	394	470	825	1,229	711
	Commercial	275	283	227	207	193	184	162	160	176	171	244	283	213
	Industrial	64	68	62	60	56	57	52	54	59	56	63	63	59
	NGV	22	24	24	24	24	25	24	24	25	24	25	24	24
	Subtotal-CORE	1,558	1,462	1,227	1,003	802	692	623	624	654	720	1,156	1,599	1,008
NONCORE	Commercial	72	68	63	61	53	51	47	49	57	54	58	67	58
	Industrial	335	340	339	338	330	340	341	362	363	350	345	335	343
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	628	616	625	603	597	655	805	825	743	664	643	644	671
	Subtotal-NONCORE	1,054	1,045	1,046	1,022	999	1,065	1,212	1,255	1,184	1,088	1,066	1,066	1,092
WHOLESALE &	Core	267	265	223	175	139	117	111	108	112	125	191	268	175
INTERNATIONAL	Noncore Excl. EG	41	44	42	41	40	48	47	48	51	41	47	41	44
	Electric Generation (EG)	177	170	159	134	143	162	188	205	192	185	187	190	174
	Subtotal-WHOLESALE & INTL	486	479	425	351	322	327	347	361	355	350	425	499	393
	Co. Use & LUAF	59	57	52	45	41	40	42	43	42	41	51	61	48
SYSTEM TOTAL THROUGHPUT		3,157	3,043	2,750	2,421	2,163	2,125	2,224	2,283	2,235	2,200	2,698	3,226	2,542
TRANSPORTATION AND EXCHANGE														
CORE	All End Uses	11	11	9	8	6	6	5	5	5	6	9	11	8
NONCORE	Commercial/Industrial	407	409	402	399	382	391	388	410	421	405	403	402	402
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	628	616	625	603	597	655	805	825	743	664	643	644	671
	Subtotal-RETAIL	1,066	1,055	1,055	1,029	1,005	1,071	1,217	1,260	1,189	1,094	1,075	1,078	1,100
WHOLESALE & INTERNATIONAL	All End Uses	486	479	425	351	322	327	347	361	355	350	425	499	393
TOTAL TRANSPORTATION & EXCHANGE		1,551	1,535	1,480	1,380	1,327	1,398	1,564	1,621	1,544	1,444	1,500	1,577	1,494
CURTAILMENT (RETAIL & WHOLESALE)														
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0

NOTES:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	3	3	3	3	3	3	3	3	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes

3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2011

AVERAGE TEMPERATURE YEAR

FIRM CAPACITY AVAILABLE		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State Gas														
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200
LNG Capacity 3/		800	800	800	800	800	800	800	800	800	800	800	800	800
Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365
TOTAL CAPACITY AVAILABLE		4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675
GAS SUPPLY TAKEN														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State		2,778	2,674	2,370	2,047	1,784	1,751	1,836	1,897	1,846	1,800	2,296	2,831	2,157
TOTAL SUPPLY TAKEN		3,088	2,984	2,680	2,357	2,094	2,061	2,146	2,207	2,156	2,110	2,606	3,141	2,467
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL THROUGHPUT 1/		3,088	2,984	2,680	2,357	2,094	2,061	2,146	2,207	2,156	2,110	2,606	3,141	2,467
REQUIREMENTS FORECAST BY END-USE 2/														
CORE	Residential	1,205	1,095	921	716	533	429	388	388	397	473	831	1,239	716
	Commercial	272	280	224	205	191	182	161	158	174	169	242	280	211
	Industrial	63	67	61	59	55	56	51	53	58	55	61	62	58
	NGV	23	24	24	25	24	25	24	25	26	24	25	24	25
	Subtotal-CORE	1,563	1,467	1,230	1,006	803	693	624	625	655	722	1,159	1,605	1,010
NONCORE	Commercial	72	69	64	61	53	51	47	49	58	55	58	67	59
	Industrial	326	332	331	330	322	332	333	354	355	342	338	328	335
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	562	556	557	541	531	589	733	753	672	589	570	571	603
	Subtotal-NONCORE	980	977	971	952	925	992	1,133	1,176	1,104	1,006	985	986	1,016
WHOLESALE & INTERNATIONAL	Core	269	267	225	176	139	118	112	109	113	125	192	269	176
	Noncore Excl. EG	41	45	42	41	40	48	48	48	51	41	47	42	45
	Electric Generation (EG)	177	172	162	138	147	170	190	208	192	176	174	180	174
	Subtotal-WHOLESALE & INTL	487	484	429	355	327	337	349	366	356	343	413	491	394
	Co. Use & LUAF	58	56	50	44	39	39	40	41	41	40	49	59	46
SYSTEM TOTAL THROUGHPUT		3,088	2,984	2,680	2,357	2,094	2,061	2,146	2,207	2,156	2,110	2,606	3,141	2,467
TRANSPORTATION AND EXCHANGE														
CORE	All End Uses	11	11	9	7	6	6	5	5	5	6	9	11	8
NONCORE	Commercial/Industrial	398	401	394	391	375	384	380	403	413	397	396	395	394
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	562	556	557	541	531	589	733	753	672	589	570	571	603
	Subtotal-RETAIL	991	988	980	959	931	998	1,138	1,181	1,110	1,012	994	997	1,024
WHOLESALE & INTERNATIONAL	All End Uses	487	484	429	355	327	337	349	366	356	343	413	491	394
TOTAL TRANSPORTATION & EXCHANGE		1,478	1,472	1,409	1,315	1,258	1,334	1,487	1,546	1,466	1,354	1,407	1,488	1,418
CURTAILMENT (RETAIL & WHOLESALE)														
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0
NOTES:														
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach		3	3	3	3	3	3	3	3	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes

3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2012

AVERAGE TEMPERATURE YEAR

FIRM CAPACITY AVAILABLE		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State Gas														
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200
LNG Capacity 3/		800	800	800	800	800	800	800	800	800	800	800	800	800
Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365
TOTAL CAPACITY AVAILABLE		4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675
GAS SUPPLY TAKEN														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State		2,789	2,604	2,405	2,069	1,788	1,766	1,859	1,915	1,873	1,820	2,299	2,851	2,170
TOTAL SUPPLY TAKEN		3,099	2,914	2,715	2,379	2,098	2,076	2,169	2,225	2,183	2,130	2,609	3,161	2,480
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL THROUGHPUT 1/		3,099	2,914	2,715	2,379	2,098	2,076	2,169	2,225	2,183	2,130	2,609	3,161	2,480
REQUIREMENTS FORECAST BY END-USE 2/														
CORE	Residential	1,212	1,063	926	721	536	432	390	390	399	476	835	1,246	718
	Commercial	268	267	221	202	188	180	159	156	171	167	238	276	207
	Industrial	62	63	59	58	54	55	49	52	56	54	60	60	57
	NGV	23	24	25	26	25	26	25	26	27	25	26	25	25
	Subtotal-CORE	1,565	1,417	1,232	1,006	803	692	623	624	654	721	1,159	1,607	1,008
NONCORE	Commercial	72	67	64	61	53	52	48	49	58	55	58	68	59
	Industrial	327	327	331	331	322	333	333	354	356	343	338	328	335
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	566	549	575	550	533	601	747	768	694	602	572	580	612
	Subtotal-NONCORE	984	963	990	962	928	1,005	1,148	1,190	1,128	1,020	988	996	1,025
WHOLESALE &	Core	271	259	226	177	140	119	112	109	113	126	192	271	176
INTERNATIONAL	Noncore Excl. EG	41	43	42	41	40	48	48	48	51	41	47	42	44
	Electric Generation (EG)	179	177	175	147	148	172	197	211	197	182	173	187	179
	Subtotal-WHOLESALE & INTL	492	479	443	366	328	339	357	369	361	349	413	499	399
	Co. Use & LUAF	58	55	51	45	39	39	41	42	41	40	49	59	47
SYSTEM TOTAL THROUGHPUT		3,099	2,914	2,715	2,379	2,098	2,076	2,169	2,225	2,183	2,130	2,609	3,161	2,480
TRANSPORTATION AND EXCHANGE														
CORE	All End Uses	11	10	9	7	6	6	5	5	5	6	9	11	8
NONCORE	Commercial/Industrial	399	394	395	392	375	384	381	403	414	398	396	396	394
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	566	549	575	550	533	601	747	768	694	602	572	580	612
	Subtotal-RETAIL	996	973	998	969	934	1,011	1,153	1,195	1,133	1,025	996	1,007	1,033
WHOLESALE & INTERNATIONAL	All End Uses	492	479	443	366	328	339	357	369	361	349	413	499	399
TOTAL TRANSPORTATION & EXCHANGE		1,487	1,452	1,441	1,335	1,262	1,350	1,509	1,564	1,494	1,374	1,409	1,506	1,432
CURTAILMENT (RETAIL & WHOLESALE)														
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0
NOTES:														
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach		3	3	3	3	3	3	3	3	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes

3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2015

AVERAGE TEMPERATURE YEAR

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
FIRM CAPACITY AVAILABLE														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State Gas														
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200
LNG Capacity 3/		800	800	800	800	800	800	800	800	800	800	800	800	800
Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365
TOTAL CAPACITY AVAILABLE		4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675
GAS SUPPLY TAKEN														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State		2,817	2,715	2,416	2,102	1,821	1,793	1,893	1,966	1,898	1,834	2,307	2,853	2,199
TOTAL SUPPLY TAKEN		3,127	3,025	2,726	2,412	2,131	2,103	2,203	2,276	2,208	2,144	2,617	3,163	2,509
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL THROUGHPUT 1/		3,127	3,025	2,726	2,412	2,131	2,103	2,203	2,276	2,208	2,144	2,617	3,163	2,509
REQUIREMENTS FORECAST BY END-USE 2/														
CORE	Residential	1,234	1,122	944	734	546	440	398	398	407	485	851	1,269	734
	Commercial	255	262	210	192	179	171	151	149	163	159	226	262	198
	Industrial	57	60	55	53	50	50	45	48	52	49	55	56	52
	NGV	25	27	27	28	27	28	27	27	29	27	28	27	27
	Subtotal-CORE	1,571	1,471	1,235	1,007	801	689	621	622	651	720	1,161	1,614	1,011
NONCORE	Commercial	73	70	65	62	54	52	48	50	59	56	59	69	60
	Industrial	329	334	333	332	324	334	335	356	357	344	340	330	337
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	582	576	587	576	562	627	785	820	723	621	581	588	636
	Subtotal-NONCORE	1,004	999	1,004	990	959	1,033	1,188	1,245	1,158	1,040	1,000	1,006	1,053
WHOLESALE & INTERNATIONAL	Core	276	273	229	179	141	119	113	110	114	127	195	275	179
	Noncore Excl. EG	42	45	43	42	41	48	48	49	52	41	47	42	45
	Electric Generation (EG)	176	179	164	150	149	174	192	208	192	176	165	167	174
	Subtotal-WHOLESALE & INTL	494	497	435	370	330	341	353	367	358	344	408	484	398
	Co. Use & LUAF	59	57	51	45	40	40	41	43	41	40	49	59	47
SYSTEM TOTAL THROUGHPUT		3,127	3,025	2,726	2,412	2,131	2,103	2,203	2,276	2,208	2,144	2,617	3,163	2,509
TRANSPORTATION AND EXCHANGE														
CORE	All End Uses	11	11	9	7	6	5	5	5	5	5	9	11	7
NONCORE	Commercial/Industrial	402	404	398	394	378	386	383	405	416	400	399	399	397
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	582	576	587	576	562	627	785	820	723	621	581	588	636
	Subtotal-RETAIL	1,015	1,010	1,013	997	965	1,038	1,193	1,249	1,164	1,046	1,008	1,017	1,060
WHOLESALE & INTERNATIONAL	All End Uses	494	497	435	370	330	341	353	367	358	344	408	484	398
TOTAL TRANSPORTATION & EXCHANGE		1,508	1,507	1,448	1,368	1,296	1,379	1,546	1,616	1,521	1,390	1,416	1,501	1,458
CURTAILMENT (RETAIL & WHOLESALE)														
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0
NOTES:														
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach		3	3	3	3	3	3	3	3	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes
3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2020

AVERAGE TEMPERATURE YEAR

FIRM CAPACITY AVAILABLE		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State Gas														
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200
LNG Capacity 3/		800	800	800	800	800	800	800	800	800	800	800	800	800
Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365
TOTAL CAPACITY AVAILABLE		4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675
GAS SUPPLY TAKEN														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State		2,838	2,635	2,446	2,135	1,852	1,844	1,955	2,053	1,951	1,861	2,375	2,974	2,243
TOTAL SUPPLY TAKEN		3,148	2,945	2,756	2,445	2,162	2,154	2,265	2,363	2,261	2,171	2,685	3,284	2,553
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL THROUGHPUT 1/		3,148	2,945	2,756	2,445	2,162	2,154	2,265	2,363	2,261	2,171	2,685	3,284	2,553
REQUIREMENTS FORECAST BY END-USE 2/														
CORE	Residential	1,256	1,102	960	747	555	448	405	405	414	493	866	1,291	744
	Commercial	226	225	187	171	160	153	135	134	146	142	202	233	176
	Industrial	47	48	45	44	41	42	37	39	43	41	46	46	43
	NGV	28	29	30	31	30	31	30	30	32	30	31	30	30
	Subtotal-CORE	1,557	1,404	1,222	992	786	673	607	608	635	706	1,144	1,600	994
NONCORE	Commercial	74	68	66	63	54	53	49	50	59	56	60	69	60
	Industrial	321	320	324	324	316	326	326	347	348	336	331	322	328
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	614	597	624	611	600	689	859	915	788	662	653	686	692
	Subtotal-NONCORE	1,029	1,005	1,034	1,017	989	1,087	1,253	1,331	1,216	1,073	1,063	1,097	1,100
WHOLESALE &	Core	287	274	238	185	145	123	116	114	117	131	202	286	185
INTERNATIONAL	Noncore Excl. EG	43	44	43	43	42	49	49	49	52	42	48	43	46
	Electric Generation (EG)	174	162	167	162	159	182	197	216	199	178	177	197	181
	Subtotal-WHOLESALE & INTL	504	480	448	389	346	354	362	380	368	351	427	526	411
	Co. Use & LUAF	59	55	52	46	41	40	43	44	42	41	50	62	48
SYSTEM TOTAL THROUGHPUT		3,148	2,945	2,756	2,445	2,162	2,154	2,265	2,363	2,261	2,171	2,685	3,284	2,553
TRANSPORTATION AND EXCHANGE														
CORE	All End Uses	11	10	8	7	6	5	4	4	5	5	8	11	7
NONCORE	Commercial/Industrial	395	389	390	387	370	378	375	397	408	392	391	391	388
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	614	597	624	611	600	689	859	915	788	662	653	686	692
	Subtotal-RETAIL	1,040	1,015	1,042	1,024	995	1,092	1,258	1,336	1,221	1,078	1,071	1,107	1,107
WHOLESALE & INTERNATIONAL	All End Uses	504	480	448	389	346	354	362	380	368	351	427	526	411
TOTAL TRANSPORTATION & EXCHANGE		1,543	1,495	1,490	1,413	1,341	1,446	1,620	1,715	1,589	1,429	1,499	1,633	1,518
CURTAILMENT (RETAIL & WHOLESALE)														
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0
NOTES:														
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach		3	3	3	3	3	3	3	3	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes
3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED FOR YEAR: 2025

AVERAGE TEMPERATURE YEAR

FIRM CAPACITY AVAILABLE		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State Gas														
Mojave (Hector Road)		50	50	50	50	50	50	50	50	50	50	50	50	50
El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
El Paso Natural Gas Co. (Topock)		540	540	540	540	540	540	540	540	540	540	540	540	540
Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	800	800	800	800	800	800	800	800
Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	765	765	765	765	765	765	765	765
Kern-Mojave (Kramer Junction)		200	200	200	200	200	200	200	200	200	200	200	200	200
LNG Capacity 3/		800	800	800	800	800	800	800	800	800	800	800	800	800
Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365	4,365
TOTAL CAPACITY AVAILABLE		4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675
GAS SUPPLY TAKEN														
California Source Gas		310	310	310	310	310	310	310	310	310	310	310	310	310
Out-of-State		2,949	2,841	2,517	2,225	1,964	2,029	2,232	2,320	2,160	1,977	2,518	3,125	2,403
TOTAL SUPPLY TAKEN		3,259	3,151	2,827	2,535	2,274	2,339	2,542	2,630	2,470	2,287	2,828	3,435	2,713
Net Underground Storage Withdrawal		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL THROUGHPUT 1/		3,259	3,151	2,827	2,535	2,274	2,339	2,542	2,630	2,470	2,287	2,828	3,435	2,713
REQUIREMENTS FORECAST BY END-USE 2/														
CORE	Residential	1,287	1,170	984	766	569	459	415	415	424	506	888	1,323	765
	Commercial	218	224	180	165	154	148	131	129	141	137	194	225	170
	Industrial	43	45	41	40	37	38	34	36	39	37	42	42	39
	NGV	31	34	33	34	33	34	33	33	35	33	34	33	33
	Subtotal-CORE	1,579	1,473	1,238	1,004	793	678	612	613	639	712	1,157	1,623	1,008
NONCORE	Commercial	76	72	67	64	55	54	50	51	61	57	61	71	61
	Industrial	315	320	318	318	310	320	320	340	342	329	325	316	323
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	682	678	664	668	679	836	1,084	1,124	949	752	756	789	806
	Subtotal-NONCORE	1,092	1,089	1,069	1,070	1,064	1,229	1,474	1,535	1,371	1,158	1,161	1,195	1,210
WHOLESALE &	Core	302	298	249	194	152	129	122	119	123	136	210	300	194
INTERNATIONAL	Noncore Excl. EG	43	47	44	43	42	50	49	50	53	43	49	44	47
	Electric Generation (EG)	182	185	174	176	179	208	237	264	239	194	197	209	204
	Subtotal-WHOLESALE & INTL.	527	530	467	413	374	387	408	433	414	373	456	552	444
	Co. Use & LUAF	61	59	53	48	43	44	48	49	46	43	53	65	51
SYSTEM TOTAL THROUGHPUT		3,259	3,151	2,827	2,535	2,274	2,339	2,542	2,630	2,470	2,287	2,828	3,435	2,713
TRANSPORTATION AND EXCHANGE														
CORE	All End Uses	11	10	8	7	6	5	4	4	5	5	8	11	7
NONCORE	Commercial/Industrial	391	391	385	382	365	373	370	391	402	387	386	386	384
	EOR Steaming	20	20	20	20	20	20	20	20	20	20	20	20	20
	Electric Generation (EG)	682	678	664	668	679	836	1,084	1,124	949	752	756	789	806
	Subtotal-RETAIL	1,103	1,099	1,077	1,076	1,070	1,234	1,478	1,540	1,375	1,163	1,169	1,206	1,217
WHOLESALE & INTERNATIONAL	All End Uses	527	530	467	413	374	387	408	433	414	373	456	552	444
TOTAL TRANSPORTATION & EXCHANGE		1,630	1,629	1,544	1,490	1,444	1,621	1,886	1,973	1,790	1,536	1,625	1,758	1,661
CURTAILMENT (RETAIL & WHOLESALE)														
	Core	0	0	0	0	0	0	0	0	0	0	0	0	0
	Noncore	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL - Curtailment	0	0	0	0	0	0	0	0	0	0	0	0	0
NOTES:														
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach		3	3	3	3	3	3	3	3	3	3	3	3	3

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes

3/ Liquified Natural Gas delivery capacity assumed to be available in 2008

Table 48 SR Annual Forecast Data – Cold Temperature Year

TAB

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2006 THRU 2010

COLD TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE		2006	2007	2008	2009	2010
1	California Source Gas		310	310	310	310	310
	Out-of-State Gas						
2	Mojave (Hector Road)		50	50	50	50	50
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200
8	LNG Capacity 4/		0	0	800	800	800
9	Total Out-of-State Gas		3,565	3,565	4,365	4,365	4,365
10	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	4,675	4,675	4,675
	GAS SUPPLY TAKEN						
11	California Source Gas		310	310	310	310	310
12	Out-of-State		2,445	2,453	2,511	2,413	2,342
13	TOTAL SUPPLY TAKEN		2,755	2,763	2,821	2,723	2,652
14	Net Underground Storage Withdrawal		0	0	0	0	0
15	TOTAL THROUGHPUT 1/, 2/		2,755	2,763	2,821	2,723	2,652
	REQUIREMENTS FORECAST BY END-USE 3/						
16	CORE	Residential	775	774	777	785	788
17		Commercial	231	228	227	228	226
18		Industrial	65	64	63	62	61
19		NGV	20	21	22	23	24
20		Subtotal-CORE	1,091	1,087	1,089	1,098	1,099
21	NONCORE	Commercial	57	57	57	58	58
22		Industrial	349	344	343	344	343
23		EOR Steaming	35	35	30	20	20
24		Electric Generation (EG)	745	779	833	725	671
25		Subtotal-NONCORE	1,186	1,214	1,263	1,146	1,092
26	WHOLESALE &	Core	198	199	197	190	192
27	INTERNATIONAL	Noncore Excl. EG	43	43	44	44	44
28		Electric Generation (EG)	185	168	175	192	174
29		Subtotal-WHOLESALE & INTERNATIONA	426	410	416	427	411
30							
31		Co. Use & LUAF	52	52	53	51	50
32	SYSTEM TOTAL THROUGHPUT /1		2,755	2,763	2,821	2,723	2,652
	TRANSPORTATION AND EXCHANGE						
33	CORE	All End Uses	8	8	8	8	8
34	NONCORE	Commercial/Industrial	406	401	401	402	402
35		EOR Steaming	35	35	30	20	20
36		Electric Generation (EG)	745	779	833	725	671
37		Subtotal-RETAIL	1,194	1,223	1,271	1,155	1,101
	WHOLESALE &						
38	INTERNATIONAL	All End Uses	426	410	416	427	411
39	TOTAL TRANSPORTATION & EXCHANGE		1,620	1,632	1,687	1,582	1,511
	CURTAILMENT (RETAIL & WHOLESALE)						
40		Core	0	0	0	0	0
41		Noncore	0	0	0	0	0
42		TOTAL - Curtailment	0	0	0	0	0
	NOTES:						
	1/ Figures exclude pipeline bypass load losses of to non-jurisdictional gas suppliers.		864	861	876	986	1,082
	2/ Excludes own-source gas supply of gas procurement by the City of Long Beach		864	3	3	3	3

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Liquified Natural Gas delivery capacity assumed to be available in 2008.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2011 THRU 2025

COLD TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE		2011	2012	2015	2020	2025
1	California Source Gas		310	310	310	310	310
	Out-of-State Gas						
2	Mojave (Hector Road)		50	50	50	50	50
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200
8	LNG Capacity 4/		800	800	800	800	800
9	Total Out-of-State Gas		4,365	4,365	4,365	4,365	4,365
10	TOTAL CAPACITY AVAILABLE /1		4,675	4,675	4,675	4,675	4,675
	GAS SUPPLY TAKEN						
11	California Source Gas		310	310	310	310	310
12	Out-of-State		2,267	2,280	2,311	2,355	2,518
13	TOTAL SUPPLY TAKEN		2,577	2,590	2,621	2,665	2,828
14	Net Underground Storage Withdrawal		0	0	0	0	0
15	TOTAL THROUGHPUT 1/, 2/		2,577	2,590	2,621	2,665	2,828
	REQUIREMENTS FORECAST BY END-USE 3/						
16	CORE	Residential	794	796	813	825	848
17		Commercial	224	220	210	186	180
18		Industrial	60	58	54	44	40
19		NGV	25	25	27	30	33
20		Subtotal-CORE	1,102	1,099	1,104	1,086	1,102
21	NONCORE	Commercial	59	59	60	60	61
22		Industrial	335	335	337	328	323
23		EOR Steaming	20	20	20	20	20
24		Electric Generation (EG)	603	612	636	692	806
25		Subtotal-NONCORE	1,016	1,025	1,053	1,100	1,210
26	WHOLESALE &	Core	193	193	196	203	213
27	INTERNATIONAL	Noncore Excl. EG	45	44	45	46	47
28		Electric Generation (EG)	174	179	174	181	204
29		Subtotal-WHOLESALE & INTERNATION	411	417	415	429	463
30							
31		Co. Use & LUAF	48	49	49	50	53
32	SYSTEM TOTAL THROUGHPUT /1		2,577	2,590	2,621	2,665	2,828
	TRANSPORTATION AND EXCHANGE						
33	CORE	All End Uses	8	8	8	8	8
34	NONCORE	Commercial/Industrial	394	394	397	388	384
35		EOR Steaming	20	20	20	20	20
36		Electric Generation (EG)	603	612	636	692	806
37		Subtotal-RETAIL	1,024	1,034	1,061	1,108	1,217
38	WHOLESALE &						
39	INTERNATIONAL	All End Uses	411	417	415	429	463
40	TOTAL TRANSPORTATION & EXCHANGE		1,436	1,450	1,476	1,537	1,680
	CURTAILMENT (RETAIL & WHOLESALE)						
41		Core	0	0	0	0	0
42		Noncore	0	0	0	0	0
43		TOTAL - Curtailment	0	0	0	0	0

NOTES:

	2011	2012	2015	2020	2025
1/ Figures exclude pipeline bypass load losses of to non-jurisdictional gas suppliers.	1,082	1,082	1,109	1,070	1,054
2/ Excludes own-source gas supply of gas procurement by the City of Long Beach	3	3	3	3	3

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Liquified Natural Gas delivery capacity assumed to be available in 2008.

8.0 Section 4.0 Appendix

8.1. CNG Technology

Additional information supplied by EnerSea LLC on it's proprietary VORTRANS system is included in this appendix.

Functional Testing of System

Functional Test – Phase 1

GTI and PES determined an approach to a laboratory scale version of the gas handling system designed for the VOTRANS ship. The team reviewed and considered appropriate controlling regulations for the specification of the safety factor and pressure relief valve settings for the gas storage system. GTI, ABS, PES and the MCP participants reviewed the results of hazard identification studies to ascertain steps for incorporating safety devices and detection systems into the TBM.

Figure 73 GTI Facility Test Station

After acceptance of the basic dimensions of the TBM, design efforts focused on the gas supply subsystem (including compressor, ethylene glycol injection pump, pre-chiller, and possibly other gas treatment equipment or techniques), refrigerant/coolant source, liquid storage/recovery/pumping subsystem, controls and safety devices (valves, relief valves, and controller), structural arrangement of the gaseous storage system (including its support structure, flanges, and end caps), and instrumentation/sensors (e.g., pressure, temperature, flow, stress/strain measurement, vibration/acoustical, etc). The output of this design task was a set of drawings and equipment list for construction of a flexible TBM system. In parallel with the design phase, GTI worked with the MCP participants to develop and finalize a test program for the TBM. The test program details include dimensions such as:

- Normal operational control and optimization, with emphasis on gas and fluid dynamics.
- Abnormal operating situation assessments.
- Empirical mechanical system analysis such as stress/strain and dynamic structural response analysis.

GTI reviewed with participants the results of hazard identification studies pertinent to the system, which included review of safety systems as well as methods that could be used to deliberately simulate interruptions or introduce abnormal conditions during testing. A series of tests was developed to validate the performance and operation of the system under normal and abnormal operating conditions and to evaluate the robustness of the system.

Functional Test – Phase 2

The first objective of the testing program was to demonstrate the baseline operation of the system to verify equipment operation under the target conditions using a dry, lean natural gas composition. Real-time high-speed data were gathered to verify the system operation during filling and discharge. Flow rates, weights, temperatures and pressures at various points in the system were documented. Two repeat cycles were run under identical starting baseline conditions. These data were analyzed to evaluate temperature effects (e.g. gas compression or expansion, liquid heat build-up, formation of hydrates or ice) or other unexpected phenomenon.

The second objective of the testing program was to perform a series of tests to validate the performance and operation of the system under abnormal operating conditions to assess the robustness of the system. These tests were performed successfully and all data were recorded.

Cargo Cylinder Testing

The Cargo Cylinder Test included: test program definition, material specification refinement, plate and pipe production, head manufacture confirmation, AE systems investigations, test facility specification, cargo cylinder fabrication, and cargo cylinder fatigue and burst testing.

Cargo Cylinder Testing – Phase 1

The Cargo Cylinder Testing program was established during Phase 1 planning and investigation efforts of team members and the MCP participants. NSC completed pre-qualification of its ToughAce™ X80 pipe product and supplied material to NK Co. and BendTec for head forming and welding procedure qualification. PAC evaluated stress and fracture mechanics aspects of the cargo cylinders; then, designed the testing procedures and test specimens (coupons) that were used to determine the Acoustic Emissions characteristics and systems that were validated in Phase 2.

Mohr Engineering, a division of Stress Engineering was selected as the testing facility.

Cargo Cylinder Testing – Phase 2

The successful completion of the Cargo Cylinder test program verified that the fabricated cargo cylinder will meet the minimum properties as specified in the specifications and meet ABS requirements for certification as a cargo cylinder suitable for maritime service. ABS required the following issues be addressed within the testing program:

- Fatigue Test (Cyclic test)
- Burst test
- Point Load and Bending Load
- Validation of AET

- All testing performed after hydrostatic testing at less then 90% of material yield strength
- Strain gauge required to monitor stresses in the cargo cylinder
- Multiple cargo cylinders will be tested with each cargo cylinder comprised of end caps with nozzles, 3 girth welds, and 2 joints at least 2.5xOD in length (pipes may be of reduced diameter compared to the baseline 42"OD design, but wall thickness must be at least 19mm)
- Hydrostatic testing (all cargo cylinders)
- Burst test at design temperature– one cargo cylinder
- Cyclic test with bending load and burst
- Fatigue test with point load until fail

NSC, JFE and Sumitomo produced plate and pipe from X80 material slabs prepared for their pre-qualified pipe and plate materials. Material samples for Acoustic Emissions testing were sent to PAC for AE testing. Plate and pipe were sent to BendTec for cargo cylinder fabrication. PAC delivered the AE systems necessary for Acoustic Emissions data acquisition and validation testing. Cargo cylinder testing proceeded according to the agreed testing program with data acquisition, post processing, and reporting to agreed professional standards. Additional details regarding the results can be obtained on request.

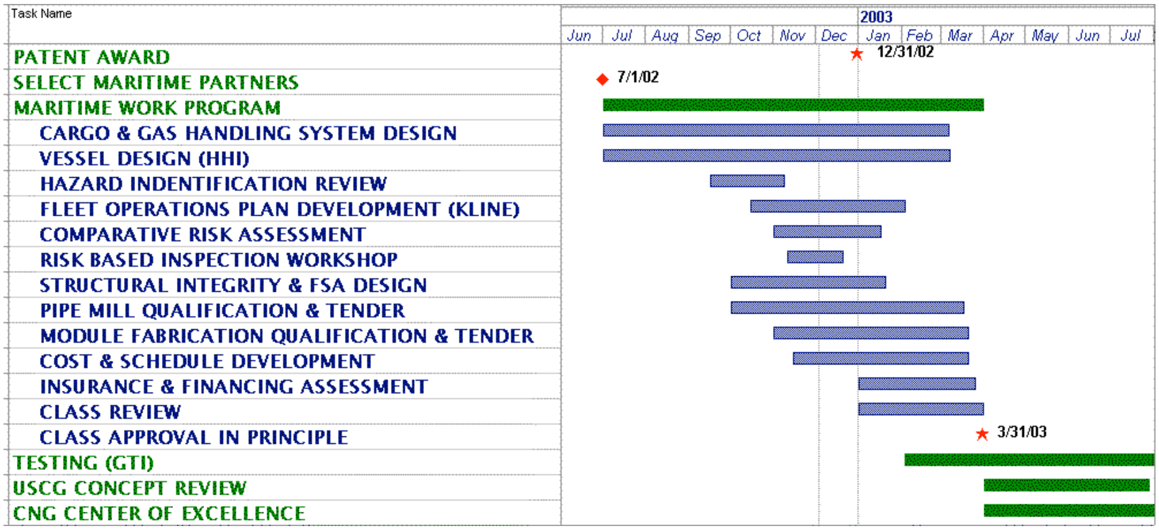
Case-Specific Conceptual Design V800 "Vertical Cylinders V-Ship"

ACMA was retained and has completed the conceptual level design details on a 700 MMcf (75,000 cubic meters) capacity CNG ship carrying vertical cargo cylinders. Primary structural, stability, and powering studies established a basic set of ship design parameters that have been essential to EnerSea's ability to present a credible design to shipyards and ship owners in the Far East as part of the development and selection of the Company's strategic maritime partners, HHI and K-Line.

Maritime Work Program

In order to develop the detailed design and engineering criteria for all components in a VOTRANS based CNG route, EnerSea organized a detailed work program involving a substantial commitment of resources from each participant. EnerSea selected a super-major E&P company to participate in the Company's Maritime Work Program in conjunction with HHI, K-Line and EnerSea's other strategic development consultants (Paragon Engineering Services, Inc. ("PES"), Alan C. McClure Associates, Inc. ("ACMA") and the American Bureau of Shipping (ABS) to complete the preliminary engineering and design of ships and unloading/loading facilities employing EnerSea's VOTRANS technology. EnerSea initiated the Maritime Work Program in July 2002 and completed the program in March 2003.

Figure 74 VOTRANS Maritime Work Program Schedule



VOTRANS Gas Handling System Study Report (Fluor Daniels)

Fluor was retained by EnerSea to conduct a third party review and evaluation of its VOTRANS Gas Handling System and to develop a gas dynamic simulation model to reflect the baseline operation for loading and offloading of a CNG marine transport vessel.

A novel feature of the VOTRANS system is its use of displacement fluid to achieve isobaric operation during both loading and offloading operations. The developed gas dynamics model incorporates the use of such displacement fluid and addresses dynamic responses associated with controlled loading and offloading. The model also enables the operator to evaluate the robustness of the baseline operation to operational disturbances caused by either equipment failure or a malfunction of the operation sequencing logic. Design and operating criteria provided by EnerSea were utilized in the process.

Prior to development of the simulation model, Fluor reviewed the existing VOTRANS system design and documentation to provide a critique and at the same time gain sufficient system and design understanding to develop the dynamic simulation model.

The dynamic response analysis indicates the loading and offloading operations are quite stable with very small variations in cargo cylinder pressure and gas temperatures. These variations are due to the operation sequencing and opening and closing respective valves. This confirms the steady state nature of the operation. The model can also be used to simulate any upset conditions and system responses. The model provides a valuable tool for assessing the robustness of planned operations to a wide range of unplanned or emergency situations and should be recognized as an asset for future engineering studies.

EnerSea Intellectual Property

EnerSea has established what is generally considered to be the industry's leading compressed natural gas marine transport and storage technology. The body of this technology and know-how has been developed based on the extensive industry and technical experience of the EnerSea management team and strategic partners. EnerSea's IP consists of patents and filings with the U.S. Patent and Trademark Office for our optimization and operational principles, as well as through filings with strategically selected international patent offices. International protections include filings with Paris Treaty members, including Canada, Korea, Japan and Venezuela.

Patent No.:	US 6,584,781 B2
Issue Date:	July 1, 2003
Filing Date:	August 31, 2001
For:	Methods and Apparatus for Compressed Gas
Location:	U.S.
Title:	*"VOTRANS – Volume Optimized Transport of CNG by Ships and/or Barges"*
Description:	This invention is a concept whereby commercial marine transportation of compressed natural gas may be realized.

Application:	20020046773
Filing Date:	August 31, 2001
For:	Methods and Apparatus for Compressed Gas
Location:	U.S.
Title:	*"VOLANDS – Volume Optimized* ***Land*** *Storage of CNG"*
Description:	This invention is a concept whereby commercial storage of compressed natural gas for application with power produces, gas distributors and consumers to practice "peak-shaving" as a means to manage energy costs.

Patent No.:	US 6,655,155 B2
Issue Date:	December 2, 2003
Filing Date:	October 8, 2002
For:	Methods and Apparatus for **Loading** Compressed Gas (CIP)
Location:	U.S., Continuation-In-Part Patent Application
Title:	*"Methods and Apparatus for* ***Loading*** *Compressed Gas"*
Description:	This invention is a concept whereby chilled compressed natural gas can be loaded into storage vessels using a (non-freezing) liquid displacement methodology.

Patent No.:	US 6,725,671 B2
Issue Date:	April 27, 2004
Filing Date:	December 11, 2002
For:	Methods and Apparatus for Compressed Gas (Divisional)
Location:	U.S., (Divisional)
Title:	*"Cocktailing Practice"*
Description:	Method describes means to optimize containment characteristics for a specific gas by adding heavier components to the gas stream to maximize storage in a specific (existing) VOTRANS containment system.

8.2. CCNG Technology

This appendix will further discuss CCNG technologies and their potential application. This information was provided by Expansion Energy LLC, the primary technology developer and commercialization entity.

CCNG Comprehensive Solutions

A comprehensive solution to NG storage, pipeline throughput capacity, and the logistics of optimally connecting storage systems to end users by way of a limited and imperfect pipeline grid can have many components.

Conservation of the product stored and transported, and the available capacity of the system can yield short-term improvements in deliverability. Beyond conservation, policy makers can examine other short- and long-term steps to improve the existing NG storage and distribution system. Those steps would include the following:

- Reduce line losses in all existing and future pipelines;
- Recover heat of compression and waste heat produced by natural gas fueled engines such as those that drive compressors;
- Utilize off-peak capacity at power plants and compressor stations to store kW / NG for peak period release;
- Eliminate boil-off from all existing and future LNG systems;
- Encourage distributive power production, using local LNG/CCNG production and storage systems.

One way to get closer to an ideal NG distribution system, with fewer hurdles, is to begin a program of CCNG pipeline construction. For example, relatively short-run CCNG "links" might eliminate or reduce the impacts of existing bottlenecks in the system. Other links might connect existing regional pipelines with excess capacity (say, from the Rocky Mountains) to not-too-distant portions of the gas grid that now operate with constrained capacity.

Such CCNG pipeline links might be deployed as new construction (within existing NG pipeline right of ways), or may be "retrofits" of existing "warm" carbon-steel pipelines. For example, Sempra's LNG import terminal in Baja California might augment its send-out regime as follows. Instead of vaporizing all of the imported LNG, it would "pump" LNG to pressure, producing CCNG that would be as dense (or slightly denser) then LNG. The CCNG would then be transported north to San Diego in a dedicated CCNG pipeline, which would be appropriately insulated and which would have pumping stations along the way. Depending on the total length of the line, and the selected "arrival temperature" of the product in San Diego, there may not need to be any re-refrigeration stations along the route.

It should be noted that in the "continuum" from very cold LNG/CCNG, say, at -260°F and 1,200 psia, to standard CNG at 50°F and 100 psia, there are an infinite number of temperature and pressure values with their corresponding densities. An optimally designed CCNG pipeline would make "transitions" between various "states" of the NG in response to design goals related to pressure drop and the intended arrival temperature and pressure of the once-CCNG as CNG. For example, if warming were desired, prior to inserting CCNG to a standard CNG line, then the last segment of the CCNG line would not be insulated.

Such CCNG pipelines, while unprecedented, can be built with existing technologies, and will likely cost significantly less than the same length conventional pipeline with the same throughput. In addition to lower capital costs, the operating costs of a CCNG pipeline will be lower, because pumping requires substantially less energy than compression, and because the source LNG will not need to be vaporized. This model is certainly within the realm of possibilities for the California Energy Commission's comprehensive 15-year planning process. (Shorter-term solutions are examined below.) Variations on this theme can be evaluated in the context of the LNG import terminal's short- and long-term inflow rate vs. outflow demand. In other words, a CCNG send-out option may fit into Sempra's plans and that of other import terminal operators, if not now, then at some point in the near future.

For northern California, a CCNG pipeline link might connect the proposed LNG import terminals in Oregon and/or offshore. A CCNG link to an offshore terminal would substantially eliminate the need for large LNG storage tanks, thus yielding fewer and smaller off-shore structures, which may result in less local opposition.

Expansion Energy LLC has identified a potential California gas-processing equipment manufacturer and contractor who has the capacity and inclination to produce, deliver, and install a VX Cycle plant and provide a site for field evaluation of the system.

In summary, the ideal long-term solution to the three operating scenarios outlined in Section 4.0 is to comprehensively integrate LNG/CCNG production (or import) sources with CCNG pipelines. The production sources would include existing power plants that can redirect off peak excessive capacity to LNG/CCNG production and existing compressor stations that would be upgraded to produce LNG/CCNG.

VPX System

The models discussed in this research have common themes. In all cases, the overall delivery and storage problem would be mitigated by optimally located LNG/CCNG production, storage and transport systems that, together, substantially increase the density of natural gas by refrigeration. The solutions outlined can achieve a more than 60-fold density increase when compared to warm NG in a 100-psia pipeline. However, such large density increases require the deployment of specialized equipment at strategic locations within the NG network.

Expansion Energy LLC has developed a complementary approach to increasing pipeline throughput that relies less on a few, widely placed "high-density-producing" elements and allows significant increases in system capacity with relatively low-tech, broadly deployed components.

The invention, tentatively called "Vandor's Pipeline Expansion System" ("VPX") is not a substitute for the systems and methods outlined above. Instead, VPX is a set of steps that achieve incremental expansion of pipeline capacity. Those steps would be taken in a "preliminary" effort to achieve the more dramatic capacity increases that CCNG systems can produce. For example, in one application of VPX, the throughput in a standard pipeline can increase 25% to 40% above existing maximum throughput.

While that is not as dramatic as the, say, 7-times throughput of a new CCNG pipeline (when compared to the same sized standard line operating at the same pressure), the 25% to 40% increase offered by VPX can be achieved now, with readily available equipment, and with relatively minor modifications to the existing natural gas infrastructure. If implemented, the 25% to 40% increase in capacity, generalized across as much of the California natural gas grid as deemed appropriate, would significantly mitigate delivery issues, allowing the utilities and policy makers time to evaluate, design, permit, and construct individual components of the CCNG-system outlined above.

A comprehensive plan for improving pipeline capacity and local storage options would start with VPX, (including the removal of water and CO_2 from the product stream) and, over time, would continue with the CCNG models outlined above.

VPX Technology Status

The VPX solution for enhancing throughput in existing pipelines may be the easiest to advance because it does not require new rights of way or any significant land area for new equipment, and may not require any new permitting protocols. For the sake of simplicity, the site selection process should seek existing pipeline segments that might be easily "isolated" for monitoring, allowing the sponsor to fully measure the increases in throughput. For example, the end of a line or network might work better than a middle segment.

The selected project does not need to be a single line. It could include a "main line" and its laterals, where that network routinely experiences capacity shortfalls. Community support will likely be attainable because VPX has a "low profile" and achieves its goals with more "familiar" technology than the VX Cycle.

The criteria for site selection would include several factors:

- An "end" portion of a larger NG pipeline network that has more demand than capacity;
- A customer base that needs NG year-round, not just in a single season;
- Availability of a modestly sized property (say, 5,000 sq. ft.) at or near an existing metering or booster compression station, allowing for the installation of new equipment;
- A context where a steady increase of 25% to 40% above today's capacity would be welcome by the end-use community.

To summarize, the selected VPX demonstration would allow the gas pipeline company (the sponsor) to increase throughput in a specific pipeline network, demonstrate the viability of VPX, and to gain experience in the technical, economic, and public outreach aspects of VPX.

9.0 Section 5.0 Appendix

9.1. Review of Federal and State Storage Expansion Decisions

Introduction

A value-based approach to storage was discussed in a 2003 Technology Progress Report for the Gas Storage Technology Consortium[63]:

Gas storage is a critical element of the natural gas industry. Producers, transmission and distribution companies, marketers, and end-users all benefit directly from the load balancing function of storage. The unbundling of gas transmission services (as part of regulatory changes) started a process that has fundamentally changed the way storage is used and valued. ***As an unbundled service, the value of storage in minimizing overall costs to consumers is increasingly being recovered at rates that reflect its value.*** Moreover, the traditional marketplace has differentiated between various types of storage services and has increasingly rewarded flexibility, safety, and reliability.

The FERC's Summer 2006 Storage Overview addresses the relationship between gas storage improvements and LNG supplies, noting that LNG is needed to meet future gas demand as domestic and Canadian production flattens. In this regard, the Overview states as follows:

An excellent way to meet the need for more gas supply during periods of high demand is to construct more gas storage. This allows not only domestically produced gas to be put underground for cold weather consumption, but also LNG, which can be delivered, regasified and stored during those months when LNG is not in high worldwide demand, especially in the Atlantic Basin, and prices are, hopefully, at lower levels. Given the high level of working gas in storage coming out of last winter, it will not take long to fill up the remaining capacity. At that point, the U.S. will not be able to take advantage of the cheaper, plentiful supply of LNG. An increase in the amount of storage capacity will allow U.S. LNG capacity holders to take advantage of market developments and be in a better position to meet gas demands during the heating season at less volatile and, hopefully, lower prices.[64]

And the FERC Staff's September 30, 2004 Report on the Current State of and Issues Concerning Underground Natural Gas Storage speaks to the rapid increase in LNG imports and need for more storage facilities:

Quantities of LNG imports into the United States have increased almost six-fold from 85 Bcf in 1998 to 507 Bcf in 2003. Should LNG imports grow in the future as projected, more storage facilities (LNG tanks, salt cavern storage and depleted offshore oil/gas reservoirs) will be needed.[65]

---

[63] http://www.osti.gov/bridge/servlets/purl/823307-nDeMWA/native/823307.pdf

[64] https://www.ferc.gov/EventCalendar/Files/20060615103625-A-3-TALKING-PTS.pdf

[65] https://www.ferc.gov/EventCalendar/Files/20041020081349-final-gs-report.pdf

In summarizing its Order No. 678, the FERC stated as follows:[66]:

First, the Final Rule modifies the Commission's market-power analysis to better reflect the competitive alternatives to storage. Specifically, we adopt a more expansive definition of the relevant product market for storage to explicitly include close substitutes for gas storage services, including pipeline capacity, local production, and liquefied natural gas (LNG) supplies. The Commission will evaluate potential substitutes in the context of individual applications for market-based rates. The Final Rule eliminates the NOPR's requirement that storage providers granted market-based rates on the basis of a market power analysis file updated market-power analyses every five years. Instead, storage providers with market shares of ten percent or less would generally be exempt from such a requirement. We will consider in individual cases whether the specific facts and circumstances presented require additional reporting for other storage providers.

Second, the Final Rule adopts regulations implementing section 312 of EPAct 2005, which permits the Commission to authorize market-based rates even if a lack of market power has not been demonstrated, in circumstances where market-based rates are in the public interest and necessary to encourage the construction of storage capacity in the area needing storage services and that customers are adequately protected. Finding that the definition of facilities eligible for treatment under new NGA section 4(f) is ambiguous, the Commission defines ``facilities'' as it traditionally has for purposes of the certification requirements of section 7(c). However, to receive market-based rate authorization, the storage provider will still need to satisfy the other requirements of section 4(f).

And in further describing its more expansive definition of the relevant market for storage, the FERC stated the following:

The Commission finds it is appropriate to adopt a more expansive definition of the relevant product market for storage to explicitly include close substitutes for gas storage services, including pipeline capacity and local production/LNG supplies. As explained below, this modification to our market-power analysis better reflects the competitive alternatives to storage and is supported by changes in the natural gas markets that have occurred since the mid 1990s. In today's markets, these non-storage products may well serve as adequate substitutes for gas storage in appropriate circumstances.

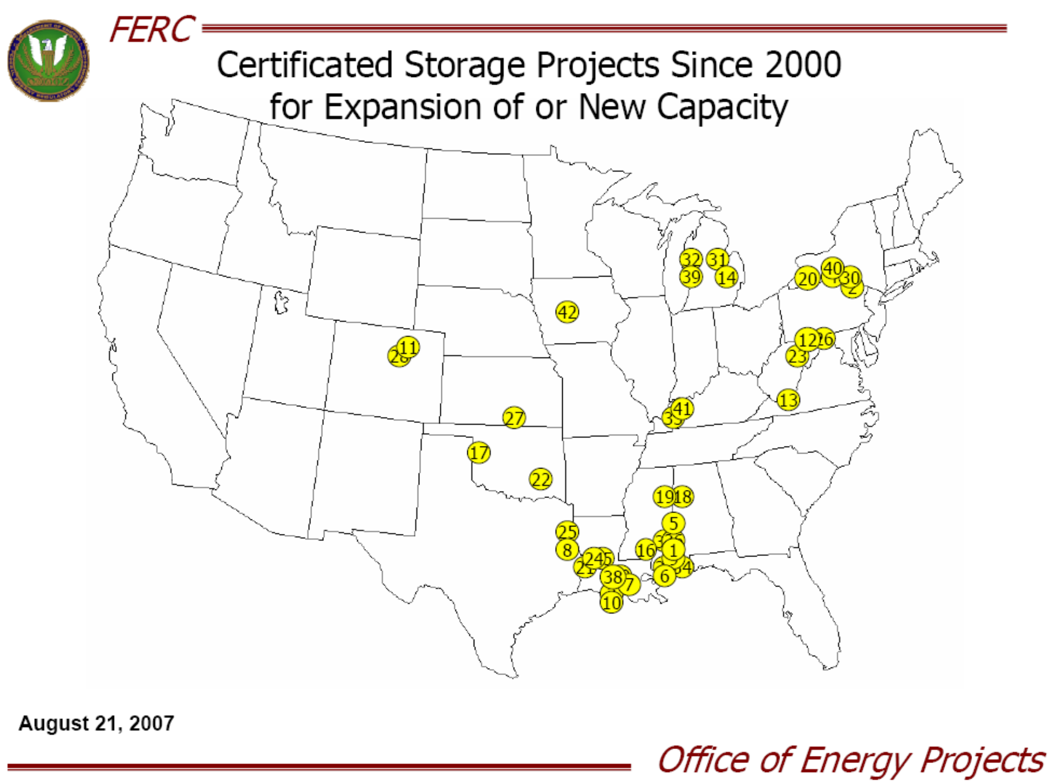
As we explained in Order No. 637, the deregulation of wellhead natural gas prices, the advent of open-access transportation and the requirement that interstate pipelines offer unbundled open-access transportation service, has increased competition and efficiency in both the gas commodity and transportation market. Market centers have developed both upstream in the production area and downstream in the market area, providing shippers with greater gas and capacity choices. The wholesale market has grown with new participants that have the ability to deliver gas into many markets. The expansion of the product market definition to include close substitutes simply recognizes that buyers and sellers have a greater number of alternatives from which to choose in order to obtain and deliver gas supplies. From an end-use customer's perspective, gas is fungible, whether it comes from storage, local production or more distant supplies transported by pipelines. Competition with storage can come from any of these sources

[66] http://www.epa.gov/fedrgstr/EPA-IMPACT/2006/June/Day-27/i5642.htm

that can deliver gas in the same market as the storage facility. For these reasons, we will permit a storage applicant to include non-storage products and services, including pipeline capacity and local production/LNG supply in the calculation of its market concentration and market share.

The Commission recognizes, however, that local production, LNG and pipeline capacity may not be good alternatives to an applicant's storage services in all circumstances. For a non-storage product to be a good alternative it must be available soon enough, have a price low enough and have a quality high enough to permit customers to substitute the alternative for the applicant's services. For this reason, we will evaluate potential substitutes in the context of individual applications for market-based rates. In those proceedings, the applicant will have the burden to demonstrate that the non-storage products and services, as well as the other storage services, used in its calculation of market concentration and market share are good substitutes. Any party to the proceeding can challenge the inclusion of a particular product on the grounds that it does not meet the qualifications for a good alternative. Based on the record in the proceeding, the Commission will determine if the proposed product is in act a good alternative that will limit the exercise of significant market power by the applicant.

Review of FERC Storage and other Decisions



Certificated Storage Projects Since 2000 for Expansion of or New Capacity

Certificated capacity may not yet be fully operational

Map Index	Company (Storage Field or Project)	State(s)	County	Docket	Order Date(s)	Working Gas Capacity (Bcf)
1	Petal Gas Storage Company (Forrest)	MS	Forrest	CP99-615	3/15/2000	3.6
2	Central New York Oil & Gas Company (Stagecoach)	NY	Tioga	CP00-63	2/21/2001	13.6
3	Egan Hub Storage, LLC (Egan Hub)	LA	Acadia Parish	CP01-66	6/14/2001	4
4	Seneca Lake Storage, Inc. (Seneca Lake)	NY	Schuyler	CP01-434	2/14/2002	0.595
5	Copiah County Storage Company (Copiah)	MS	Copiah	CP02-25	6/13/2002	3.3
6	SG Resources Mississippi, LLC (Southern Pines Energy Center)	MS	Greene	CP02-229	10/10/2002	12
7	Gulf South Pipeline Company, LP (Magnolia Gas Storage Facility)	LA	Assumption Parish	CP02-155	11/21/2002	4.1
8	Natural Gas Pipeline Company of America (North Lansing Storage Field Project)	TX	Harrison	CP02-391	12/24/2002	10.7
9	Petal Gas Storage Company, LLC (Forrest)	MS	Forrest	CP02-387	2/28/2003	8
10	Egan Hub Partners, LP (Egan Hub)	LA	Acadia Parish	CP03-12	4/2/2003	8
11	Kinder Morgan Interstate Gas Transmission, LLC (Cheyenne Market Center Storage Project)	CO, NE	Weld, Cheyenne	CP03-39	9/11/2003	6
12	Dominion Transmission, Inc. (Mid Atlantic Expansion Project)	PA, VA, WV	Franklin, Fauquier, Wetzel	CP03-41	9/11/2003	5.6
13	Saltville Gas Storage Company, LLC (Saltville)	VA	Smyth	CP04-13	6/14/2004	5.8
14	ANR Pipeline Company (Storage Realignment Project)	MI	Lapeer	CP04-79	8/9/2004	4.1
15	Pine Prairie Energy Center, LLC (Pine Prairie Energy Center)	LA	Evangeline Parish	CP04-379	11/23/2004	24
16	Gulf South Pipeline Company, LP (Jackson Storage Field Project)	MS	Rankin	CP04-366	3/24/2005	1.2
17	Natural Gas Pipeline Co. of America (Sayre Storage Field Expansion)	OK	Beckham	CP05-7	3/25/2005	10
18	Freebird Gas Storage, LLC (East Detroit)	AL	Lamar	CP05-29	4/15/2005	6

19	Caledonia Energy Partners, LLC (Caledonia Energy Complex Project)	MS	Monroe	CP05-15	4/19/2005	11.72
20	Dominion Transmission, Inc. (Northeast Storage Project)	NY, PA, WV	Cattaraugus, Potter, Lewis	CP04-365	6/16/2005	9.4
21	Starks Gas Storage, LLC (Starks)	LA	Calcasieu Parish	CP05-8	7/21/2005	19
22	CenterPoint Energy Gas Transmission Co. (Chiles Dome Storage Expansion)	OK	Coal	CP05-58	7/25/2005	3
23	Hardy Gas Storage, LLC (Pre-file: PF04-14)	WV	Hardy	CP05-144	11/1/2005	12.4
24	Liberty Gas Storage, LLC (Liberty Gas Storage Project)	LA	Calcasieu Parish	CP05-92	12/8/2005	17.6
25	Natural Gas Pipeline Co. of America (Sayre Storage Field Expansion)	TX	Harrison	CP05-405	1/23/2006	10
26	Texas Eastern Transmission, LP (Accident Storage Enhancement Project)	MD	Garrett	CP05-392	2/22/2006	3
27	Northern Natural Gas Company (Cunningham Field Project)	KS	Pratt	CP05-411	3/24/2006	6
28	Unocal Windy Hill Gas Storage, LLC	CO	Morgan	CP06-19	5/19/2006	6
29	Port Barre Investments, LLC d/b/a Bobcat Gas Storage	LA	St. Landry Parrish	CP06-66	7/20/2006	12
30	Central New York Oil & Gas Company (Stagecoach Phase II Expansion Project)	NY	Tioga	CP06-64	9/22/2006	13.1
31	Bluewater Gas Storage, LLC	MI	St. Clair, Macomb	CP06-351	10/27/2006	29.2
32	ANR Pipeline Company (STEP 2007)	MI	Kalkaska	CP06-358	11/22/2006	17
33	Texas Gas Transmission, LLC (Storage Expansion Project Phase II)	KY	Muhlenberg	CP06-126	12/4/2006	11.3
34	MoBay Gas Storage Hub, Inc.	AL	Mobile Bay	CP06-398	12/20/2006	50
35	SG Resources Mississippi, LLC (Southern Pines Energy Center Expansion Project)	MS	Greene	CP02-229-002	1/24/2007	12
36	Mississippi Hub, LLC	MS	Simpson	CP07-4	2/15/2007	12
37	Petal Gas Storage, LLC (Petal Caverns Conversion Project)	MS	Forrest	CP07-30	3/28/2007	2.85
38	Port Barre Investments, LLC d/b/a Bobcat Gas Storage	LA	St. Landry Parrish	CP06-66-001	4/19/2007	1.5
39	ANR Pipeline Company (Storage Enhancement Project - 2008)	MI	Kalkaska	CP06-464	5/31/2007	14.7
40	Wycoff Gas Storage (Wycoff Storage Project)	NY	Steuben	CP03-33	10/6/2003	6
41	Texas Gas Transmission, LLC	KY	Muhlenberg	CP04-373	2/11/2005	8.2
42	Northern Natural Gas Company Redfield Expansion	IA	Dallas	CP06-461	7/1/2007	2
					Total	420.565

In a May 11, 2007 decision[67] the FERC authorized Worsham-Steed (WS) (*not pictured on the map*) to charge market-based rates for its gas storage services. In its market power analysis, WS looked at two regions, Greater Texas-Gulf Coast and Texas only. In the larger region, WS calculated (based on storage capacity) an HHI of 845, below the 1800 HHI threshold, and

[67] http://ferc.gov/EventCalendar/Files/20070511143505-PR07-6-000.pdf

indicated that no single entity controlled a market share greater than 15 percent of the market, with WS and its affiliates at 9 percent. In the smaller market region, an HHI of 1526, below the threshold, was calculated, and WS indicated that no single entity had a market share greater than 29%, with WS at 9%. A similar analysis was conducted based on deliverability, with comparable results.

It is significant to note (and this was referenced in the California Wild Goose expansion proposal covered below) that ***FERC did not show alarm at the 15 percent or even 29 percent market share*** shown for other participants in the market.

We will now look at the results and implications of other FERC decisions on requests for market-based storage facilities.

In a September 22, 2006 decision[68], FERC found (*see location 30 on the map*) that:

In support of its request for continuation and expansion of its market-based rate authority, CNYOG has filed … a market power study based on the criteria set forth in the Alternative Rate Policy Statement. CNYOG's market power analysis for the storage market defines the relevant product and geographic markets, measures market share and concentration, and evaluates other factors. The market power study defines the relevant geographic market as consisting of south central New York, and Pennsylvania, and includes firm and interruptible market-area storage facilities and interruptible wheeling services. The market power study demonstrates that numerous alternatives to the proposed services exist, given the number and size of existing storage facilities and interruptible wheeling services in the relevant market, and that no barriers to entry in the market exist. The market power study states that "CNYOG's market shares for both working gas and deliverability are well below the 20 percent safe harbor threshold level that the FERC has found indicative of a lack of market power." CNYOG's Market Power Study concludes that it will not possess market power over storage or interruptible wheeling services and that CNYOG's rates "will be rendered just and reasonable by market forces," under the Commission's standards.

The market power study shows the market concentration for both working gas and peak day deliverability to be concentrated in the New York/Pennsylvania storage market, given the HHI levels of 2225 for working gas and 2273 for deliverability. However, while the New York/Pennsylvania storage market is considered concentrated based on HHI analysis, the concentration is the result of a single storage provider, Dominion Transmission Inc. (DTI). Market shares indicate whether the applicant could hold the price above a competitive level, whereas the HHI indicates whether all providers acting in concert could collude to hold prices at a monopoly level. Although the New York/Pennsylvania storage market is concentrated with DTI holding 40 percent of the market share, the Commission has found in similar cases that this market concentration was acceptable because DTI's facilities are regulated and cost-based, thus alleviating the market power potential of relatively small applicants. CNYOG will continue to have a small share of the relevant storage market. Further, prior Commission determinations involving several market-based rate storage projects also located in the New

[68] Docket Nos. CP06-64-000 and CP06-64-001

York and Pennsylvania area have received Commission approval to charge market-based rates. In addition, CNYOG will bear any risk associated with the project if any capacity is not subscribed. Finally, we note that CNYOG's proposal for market-based rates is unopposed.

So the FERC noted that the HHI was over 2200 for both working gas and for deliverability, that this was caused by a single storage provider, DTI, and that DTI held 40 percent of the market share. Nevertheless, the FERC found that this market concentration was acceptable because of the regulated and cost-based nature of DTI's facilities, thus alleviating the market power potential of relatively small applicants. FERC, however, did not indicate what its decision would be if DTI proposed additional storage capacity or deliverability and asked for market based rates for the new storage capacity.

In an October 27, 2006 decision[69], the FERC found (*see location 31 on the map*) that it disagreed with the proposer, Bluewater, in its analysis of the applicable geography for the storage HHI analysis. FERC indicated that for Michigan, the northern Ohio territories used by Bluewater were not adequately interconnected to the Michigan pipeline and storage system to be considered within the same geographic area. Nevertheless, when the FERC recalculated the HHI based on the smaller geographic area, it still found the HHI index well below 1800, so it was not concerned with market power. FERC used another technique, which it called a "bingo card," on Bluewater's proposed hub services (e.g., wheeling and balancing), to assess the impact of various pipeline and storage interconnections on whether or not customers could bypass the Bluewater system. This is described in the following:

Bluewater's proposed hub services, *i.e.*, parking, loaning, and balancing are essentially variations of storage services and its market power analysis for storage services demonstrates that Bluewater lacks market power with regard to such services. Traditionally, in evaluating whether shippers of an applicant seeking market-based rate authority for interruptible wheeling service could obtain the same services from alternative providers, the Commission has used a matrix, referred to as a "bingo card", which identifies all possible interconnects for pipelines attached to a hub and indicates whether good alternatives exist. Bluewater presents such an analysis showing interconnections between six pipelines directly interconnected with Bluewater's system, indicating that shippers can avoid Bluewater through the use of alternative routes.

In a December 20, 2006 decision[70], the FERC found (*see location 34 on the map*) that:

The Commission uses the Herfindahl Hirschman Index (HHI) test to determine market concentration for gas pipeline and storage markets. The *Alternative Rate Policy Statement* states that a low HHI – generally less than 1,800 – indicates that sellers cannot exert market power because customers have sufficiently diverse alternatives in the relevant market. While a low HHI suggests a lack of market power, a high HHI – generally greater than 1,800 – requires a closer scrutiny in order to make a determination about a seller's ability to exert market power. MoBay's market power analysis shows an HHI calculation of 1,145 for working gas capacity, and an HHI calculation of 986 for peak day deliverability. These measures of market concentration are well below the Commission's threshold of 1,800, thus indicating that MoBay

[69] Docket Nos. CP06351-000, CP05-367-000, CP06-368-000

[70] Docket Nos. CP06-398-000, CP06-399-000, CP06-400-000

would be unable to exert market power in the relevant market area after construction of its proposed storage facilities.

In a more recent (January 2007) decision[71], FERC found (*see location 35 on the map*) that:

The Commission also found that SG Resources Mississippi (SGRM) lacked market power and granted SGRM's request to charge market-based rates for open-access firm storage and interruptible hub services, including storage-related transportation.

We use the Herfindahl Hirschman Index (HHI) test to determine market concentration for gas pipeline and storage markets. The *Alternative Rate Policy Statement* explains that a low HHI – generally less than 1,800 – indicates that sellers cannot exert market power because customers have sufficiently diverse alternatives in the relevant market. While a low HHI suggests a lack of market power, a high HHI – generally greater than 1,800 – requires closer scrutiny in order to make a determination about a seller's ability to exert market power. SGRM's market power analysis shows an HHI calculation of 1,299 for working gas capacity and an HHI calculation of 1,127 for peak day deliverability. These measures of market concentration are well below the Commission's threshold level of 1,800, indicating that SGRM does not have market power in the relevant market area.

In a May 11, 2007 decision,[72] the FERC authorized Worsham-Steed (WS) to charge market-based rates for its gas storage services. In its market power analysis, WS looked at two regions, Greater Texas-Gulf Coast and Texas only. In the larger region, WS calculated (based on storage capacity) an HHI of 845, below the 1800 HHI threshold, and indicated that no single entity controlled a market share greater than 15 percent of the market, with WS and its affiliates at 9 percent. In the smaller market region, an HHI of 1526, below the threshold, was calculated, and WS indicated that no single entity had a market share greater than 29%, with WS at 9%. A similar analysis was conducted based on deliverability, with comparable results. It is significant to note (and this was referenced in the California Wild Goose expansion proposal covered below) that ***FERC did not show alarm at the 15 percent or even 29 percent market share*** shown for other participants in the market.

It should be noted that in Avoca Natural Gas Storage, 68 FERC ¶ 61,045 (1994), the FERC approved market-based rates despite an HHI for deliverability of 4,100 in the relevant New York/Pennsylvania market, specifically noting the small size of Avoca's market share and the apparent ease of entry into the market as factors mitigating the market concentration reflected in the HHI. And FERC reached a similar result analyzing storage services in Steuben Gas Storage Co. 72 FERC ¶ 61,102 (1995); New York State Electric and Gas Corp., 81 FERC ¶ 61,020 (1997); N. E. Hub Partners, L.P., 83 FERC ¶ 61,o43 (1998); Seneca Lake Storage, Inc., 98 FERC ¶ 61,163 (2002); and Honeoye Storage Corp., 91 FERC ¶ 62,165 (2000).

It should be noted that today California's storage fields are all non-(FERC)-jurisdictional. Nevertheless, that may not be true in the future, as imported LNG or natural gas from LNG flows into California from across its borders and coasts.

[71] Docket No. CP02-229-002

[72] http://ferc.gov/EventCalendar/Files/20070511143505-PR07-6-000.pdf.

Review of CPUC Storage and other Decisions

In a December 2006 decision[73], the PUC adopted a gas transmission framework for southern California generally comparable to northern California's "Gas Accord," called the "firm access rights" (FAR) system. SoCal Gas and SDG&E are expected to implement the firm access rights system in 2008. While the FAR agreement did not address storage directly, it covered transportation access to storage as follows:

Under the FAR proposal, the holder of the FAR would be entitled to firm receipt point access at a particular receipt point. This allows the holder to ship its gas onto the SDG&E and SoCal Gas transmission system at the specified receipt point for shipment to the specified delivery point. The following four delivery points are available under the FAR proposal: (1) to an end-user pursuant to an end-user's local transportation agreement; (2) to a citygate pool account; (3) ***to a storage account***; or (4) to a contracted marketer or core aggregator transportation account. …The FAR assures the holder that its designated gas will flow to the specified delivery point ***(emphasis added)***.

The California Energy Action Plan (EAP) II[74] issued September 21, 2005 jointly by the CPUC and the Energy Commission, indicated in its natural gas section that:

To ensure reliable, long-term natural gas supplies to California at reasonable rates, the agencies must reduce or moderate demand for natural gas. Because natural gas is becoming more expensive, and because much of electricity demand growth is expected to be met by increases in natural gas-fired generation, reducing consumption of electricity and diversifying electricity generation resources are significant elements of plans to reduce natural gas demand and lower consumers' bills. *California must also promote infrastructure enhancements, such as additional* pipeline and *storage capacity*, and diversify supply sources to include liquefied natural gas (LNG). (Emphasis added.)

Further, in its third and fourth Key Actions in the natural gas section, the EAP indicated:

3. Provide that the natural gas delivery and storage system is sufficient to meet California's peak demand needs.

4. Encourage the development of additional in-state natural gas storage to enhance reliability and mitigate price volatility.

On June 18, 2001 Wild Goose filed for expansion of its storage facility. In late June 1997, Wild Goose Storage Inc. became California's newest gas utility and the state's first independent storage provider. The CPUC set out rules for independent natural gas storage facilities which exempt independent gas storage providers from traditional cost-of-service ratemaking, but subjected them to the regulatory jurisdiction of the CPUC. The developers of the project must take the risks for its commercial performance without any direct recourse to the customer of the utility system. Finding that as a new entrant without market share Wild Goose will lack market power, the CPUC authorized Wild Goose to offer its storage services at market-based rates

[73] http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/62982.htm

[74] http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

under tariffs that set rates within a rate window. In order to prevent predatory pricing, the floor rate could not be set below Wild Goose's short-run marginal cost, but Wild Goose had substantial freedom to set the ceiling rate, under the theory that its potential customers would not be captive but may choose other storage providers,

The CPUC was unable to determine that Wild Goose could not exercise market power. Neither could the CPUC determine that the potential for Wild Goose to exercise market power was fully mitigated by its lack of control of the transportation system or by other factors. The CPUC revoked the relaxed reporting requirements approved in prior decisions. The CPUC placed reporting requirements such as interactions between a utility and its affiliates, changes in status that would reflect a departure from the characteristics the Commission relied upon in approving market-based rates, and providing service agreements for short-term transactions (one year or less).[75]

CPUC comments[76] are relevant to this discussion, and are summarized in the following paragraphs.

In its original decision on Wild Goose, the CPUC found that as a new entrant, Wild Goose was without market share and hence would lack market power. Thus, the CPUC authorized Wild Goose to offer its storage at market-based rates.

In the application, Wild Goose presented a market assessment. The study analyzed four potential geographic markets, included the HHI index used by the FERC and a market share analysis, and examined product substitutes (such as flowing natural gas, balancing services, and alternative fuels). The product market was defined as two separate services: (1) working gas capacity and (2) withdrawal capacity. The four geographic markets were: (1) gas storage within northern California, (2) all gas storage in California, (3) storage connected to California throughout the west and Pacific Northwest via interstate gas transmission systems that serve California, and (4) gas storage accessible to California through connections to gas pipelines that interconnect with major pipelines serving California.

The analysis showed that both the northern California and entire California geographic areas markets are highly concentrated markets for gas storage services (market concentration occurred in three of the four markets examined; only the broadest (number 4) definition results in HHI's of less than 1800. However, under all market scenarios, the HHI is *lower* with the Wild Goose expansion project factored in than without it. For example, the HHI's for inventory for the northern California and total California markets were, respectively 3862 and 4129 without the proposed expansion and 3482 and 3690 with it. The HHI values based on withdrawal capacity are 5254 and 4795 without the proposed expansion and were reduced to 4109 and 4209 with the expansion.

Wild Goose attributed the California market concentration to the PG&E and Sempra owned storage facilities. The high market concentrations concerned the CPUC, but it recognized that the analysis provided an incomplete picture of market power potential.

[75] https://www.ferc.gov/EventCalendar/Files/20041020081349-final-gs-report.pdf
[76] http://www.cpuc.ca.gov/published/Comment_decision/17053-03.htm

The CPUC then shifted to a market share analysis. The analysis indicted that Wild Goose's market share for the northern California and total California market was, respectively, 19 percent and 8 percent based on inventory and rises to 32 percent and 15 percent with capacity expansion included. Wild Goose's market share was 9 percent and 3 percent based on withdrawal capacity, and rises to 26 percent and 10 percent.

The CPUC further noted that Wild Goose does not compete against the entire capacity of PG&E's and Sempra's storage fields, some of which is held to meet the peak load requirements of core customers and thus is not available for non-core customer purchase. (This is discussed further under the *Evaluation of Regulatory Policy and Recommendations for Any Potential Alterations* section. With this factored in the Wild Goose percentage of market share is even higher.

In its application, Wild Goose noted several alternatives to storage, including gas transportation capacity, balancing services, and alternative fuel use. The CPUC noted that alternative fuels might be limited due to environmental requirements, however.

Wild Goose also indicated several other inhibitors to the exercise of market power, including lack of control of transportation services, no advantage from affiliates (due to the small amount of transportation services they control), and that it operates under a regulated rate structure. The CPUC accepted the first two conditions as limiting, but not that it operates under a regulated rate structure (where negotiations on rates are possible).

However, the CPUC indicated that it was unable to determine whether or not Wild Goose could exercise market power, nor could it determine the potential for mitigation of market power due to the lack of control of the transportation system. The CPUC rescinded Wild Goose's exemption from simplified reporting requirements, for future monitoring, and prohibited Wild Goose from engaging in any storage transactions with its affiliates or its parent company.

On July 25, 2005 Lodi Storage filed for market-based rates for a storage field in California. In its March 2, 2006 decision[77] the commission indicated that:

In D.03-02-071, in which we (the CPUC) approved the transfer of a 50% interest in LGS's parent, Lodi Holdings, to WHP Acquisition Company, ***we emphasized that the market for gas storage and injection services in both Northern California and statewide was highly concentrated***. (Emphasis added) Although these concerns were reduced in LGS's case because of the passive nature of the investment by …, we nonetheless imposed the following restrictions on the transfer:

So that we may better monitor the evolving natural gas market, and as a condition of our approval of the change of ownership (with continued market-based rate authority), we will impose the same reporting requirements on LGS that we have imposed on Wild Goose. Specifically . . . we will prohibit LGS from engaging in any storage or hub services transactions with its ultimate parents, … or any other affiliate owned or controlled by either of those entities. In addition, we will direct LGS to promptly inform the Commission of the following changes in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing: LGS' own purchase of other natural gas facilities, transmission facilities, or substitutes for natural gas, like liquefied natural gas facilities; an increase in the

[77] http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/54190.htm

storage capacity or in the interstate or intrastate transmission capacity held by affiliates of its parents or their successors; or, merger or other acquisition involving affiliates of its parents, or their successors, and another entity that owns gas storage or transmission facilities or facilities that use natural gas as an input, such as electric generation."

The CPUC also noted that:

Nothing in the application here suggests that the gas storage injection and withdrawal markets are any less concentrated today than they were when D.03-02-071 was decided. Accordingly, we place LGS on notice that it remains subject to the restrictions quoted above. We will also require LGS to make periodic reports to the Energy Division concerning both the short-term and long-term contracts it has entered into for the Kirby Hills Facility.

In its Findings of Fact, the CPUC noted[78] that:

As stated in *Energy Action Plan II*, the proposed Facility is needed to provide additional natural gas storage facilities in Northern California so as to enhance reliability and mitigate price volatility. (Emphasis in the original.)

So while the CPUC granted conditional approval to both Wild Goose (for its expansion) and Lodi, it did indicate that it was concerned about the market concentration existing in northern California and in the entire state.

The real challenge will come if and when the larger players come before the CPUC and request market-based rates for (non-core) storage field expansions.

LNG Peakshaving Environmental Considerations

Summary of Issues that California State Agencies Address in the Review of an EIS/EIR for an LNG Project [79]

Energy Planning Issues

- Energy context within which the project is being considered
- Growing demand for natural gas and how LNG could augment natural gas supplies
- LNG supply chain and where LNG would originate
- Impacts to downstream natural gas pipeline infrastructure
- How gas prices will be determined
- Contemplated contractual terms with natural gas suppliers
- Gas quality standards and likely markets for natural gas liquids removed from LNG
- Minimum methane content of transportation fuel LNG; fleets that will use this fuel and where the LNG will be marketed
- Impact of LNG carriers on other delivery ships in port
- Implications of international agreements on reliability and pricing

[78] http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/54190-09.htm#TopOfPage

[79] http://www.energy.ca.gov/lng/working_group.html

Safety Impact Analysis Issues

- LNG safety and security regulations
- Risk analysis to eliminate or reduce potential safety hazards
- Terrorist risk; public concerns and consequences of worst-case situation
- Generic overview of Operations Plan
- Workshop for security organizations; public concerns
- Safety and emergency response planning
- Certificate programs that provide additional safety
- Mitigation measures of spread of LNG on water
- Agencies responsible for safety inspections
- Legal liability for losses due to LNG spills
- Credible scenarios at terminals and truck loading facilities and natural gas pipelines

Environmental Impact Analysis Issues

- Air Quality (e.g., criteria pollutant emissions and air emission reductions)
- Biological Resources (e.g., threatened and endangered species, sport and commercial species and marine and terrestrial species)
- Cultural Resources (e.g., historic port facilities and buried facilities)
- Environmental Justice (e.g., presence of environmental justice populations and notification of affected groups)
- Geological Hazard Resources (e.g., ground rupture, slope stability, liquefaction, seismic activity, design standards of storage tanks, and proximity to active or closed oil wells)
- Land Use (e.g., existing and planned land uses and proximity to sensitive uses)
- Noise (e.g., major noise sources and noise levels)
- Public Health (e.g., cancer risk, chronic and acute non-cancer risks)
- Socioeconomic Resources (e.g., jobs and commerce impacts, number of jobs, and projects expected capital cost/tax distribution requirements)
- Water and Soil Resources (e.g., water source and alternative sources, potential thermal discharges of water used in regasification, tanker water ballast management practices, and impacts of non-indigenous species introduced through ballast water discharges)
- Traffic and Transportation (e.g., on-shore traffic impacts, marine traffic impacts
- Visual Resources
- Waste Management (hazardous and non-hazardous)
- Worker Safety and Fire Protection

Engineering Issues

- Seismic criteria to be used for the design of the pier/wharf structure
- Highest wind speed used for analysis and design of structure and moorings

- Effects of passing vessel traffic on moored LNG tank vessel(s) factored into mooring analysis/design
- Load combinations and references
- Use of deadweight tonnage (DWT) in discussions related to wharf-vessel interactions
- Impacts of equipment/materials use and storage on above-water locations
- Alternative workspace locations

Issues of impacts to Public Trust uses of the Port and the Surrounding Region

- Navigation
- Public access (from land and sea)
- Recreation areas
- Effect of buffer zones

Project Alternative Issues

- Alternative supplies of natural gas
- Alternative on-shore and off-shore project locations
- Site and technology alternatives

Example: Environmental Impact of Long Beach LNG Import Terminal[80]

Notes: Skipped from each section 4.X.1 Significance Criteria , construction and operation impacts, and mitigation procedures

(*Probably not applicable to LNG onshore facility)

4.0 Environmental Analysis
4.1 Geology
4.1.2 Geologic Setting
4.1.3 Mineral Resources
4.1.4 Geologic Hazards (Seismic, Subsidence, Liquefaction)
4.1.5 Paleontological Resources
4.2 Soil and Sediments
4.2.2 Soil resources
4.2.3 Sediments
4.3 Water Resources
4.3.2 Ground water (Aquifers)
4.3.3 Surface Water Resources (Wetlands)
4.4 Biological Resources
4.4.2 Terrestrial Resources
4.4.3 Marine Resources*
4.4.4 Threatened and endangered Species
4.5 Land Use, Recreational, and Visual

[80] http://www.ferc.gov/industries/lng/enviro/eis/2005/10-07-05-eis.asp

4.5.2 Land Use and Ownership (Pipelines and Associated Above Ground Facilities)
4.5.3 Existing Residences and Planned Communities
4.5.4 Hazardous Waste Facilities
4.5.5 Recreational and Special Use Facilities
4.5.6 Visual Resources
4.6 Socioeconomics
4.6.2 Population
4.6.3 Economy and Employment
4.6.4 Housing
4.6.5 Public Services
4.6.6 Utilities and Service Systems (Electric, Water, Waste Water, Solid Waste Disposal)
4.6.7 Property Values
4.6.8 Tax Revenues
4.6.9 Environmental Justice
4.7 Transportation
4.7.2 Ground Transportation
4.7.3 Marine Transportation*
4.7.4 Air Transportation
4.8 Cultural Resources
4.8.2 Regulatory Requirements (Historic Preservation)
4.8.3 Cultural Resource Assessment
4.8.4 Unanticipated Discoveries
4.8.5 Native American Consultation
4.9 Air Quality
4.9.2 Environmental Setting (Climate, Ambient Air Quality, Attainment Status, Air Quality Management Plan, Toxic Air Contaminants)
4.9.3 Local Regulations (AQMD – Dispersion Modeling of SO_2, CO, NOx, PM_{10}, $PM_{2.5}$
4.9.6 General Conformity Determination
4.9.7 Health Risk Assessment
4.9.8 LNG Consumers
4.10 Noise
4.10.2 Environmental Setting
4.10.3 Regulatory Requirements
4.11 Reliability and Safety
4.11.2 LNG Import Terminal Facilities* (but would be replaced with LNG Peak Shaving Facilities)
4.11.3 LNG Hazards
4.11.4 Storage and Retention Facilities
4.11.5 Siting Requirements (Thermal Exclusion Zone, Impoundment Systems, Vapor Dispersion Exclusion Zone)
4.11.6 Cryogenic Design and Technical Review
4.11.7 Marine Safety*
4.11.8 Terrorism and Security Issues
4.11.9 Emergency Response and Evacuation Plans
4.11.10 POLB (Port of Long Beach) Hazards Analysis*
4.11.11 LNG Truck Safety

4.11.12 Pipeline Facilities
4.11.13 Conclusions on Safety Issues
4.12 Cumulative Impacts
Repeat of air, water, land use, etc.
4.13 Growth Inducing Impacts