# Pipeline and Storage Infrastructure Requirements for a 30 Tcf U.S. Gas Market

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# 1. Executive Summary

Several leading energy market forecasts predict a significant increase in annual U.S. natural gas demand, from 22.4 trillion cubic feet (Tcf) in 1997 to 30 Tcf by 2010 or shortly thereafter. While they may differ on the timing and the composition of the demand growth, the studies agree there must be considerable market growth in power generation and industrial sectors—both of which are price-sensitive. The fundamental challenge facing the natural gas industry is to serve these markets at competitive prices.

Natural gas studies traditionally focus on the two ends of the natural gas market—the production of gas at the wellhead and gas penetration in end-use markets. This study builds on the 30 Tcf market forecasts by creating realistic scenarios to estimate the incremental gas pipeline and storage infrastructure needed to support that market and assesses the gas industry's challenges in providing that infrastructure.

This study finds that a 30 Tcf market is economically possible, although all segments of the natural gas industry will face challenges in growing the market to that level. The study offers the following conclusions:

#### — MARKET GROWTH —

Growth in the power generation and industrial sectors will underpin the 30 Tcf market in the United States. Substantial growth will occur in all regions, with the highest percentage growth expected in the South Atlantic and in the Northeast.

#### — TRANSMISSION EXPENDITURES —

Total U.S. gas transmission expenditures from 1998 to 2010 are estimated to be between $30 and $32 billion, with a projected annual average of $2.3 billion to $2.5 billion—somewhat higher than the actual average annual capital expenditures over the last 15 years. Half of the new expenditures will go toward new interregional transmission capacity, 9 percent for new production area links, 15 percent for new demand area connections and 26 percent to replace existing pipeline and compressor facilities.

#### — STORAGE CAPACITY EXPENDITURES —

Total U.S. gas storage expenditures during that same time are projected to total $2.2 billion to $2.4 billion through 2010, or $180 million to $190 million per year. This is in line with the actual average expenditures of $200 million per year over the last 15 years. Most of the additional storage capacity is needed in the U.S. Northeast.

#### — INTERNATIONAL INTEGRATION —

The North American gas market will be between 36.2 and 36.4 Tcf in 2010, with 18 percent of this gas crossing international borders before reaching consumers. This makes the integration of business strategies, infrastructure and operations among Canadian, Mexican and U.S. companies increasingly important.

The study also outlines the following challenges to the natural gas industry:

#### — PIPELINE / STORAGE —

The pipeline and storage industries must be able to earn adequate returns to attract capital, achieve a balanced environmental permitting process and foster international infrastructure integration.

#### — PRODUCING SECTOR —

The gas supply sector must grow U.S. production from 19.7 Tcf in 1997 to more than 26.2 Tcf in 2010, an increase of 2.2 to 2.3 percent per year. This will require an increase in annual gas well completions from 11,600 in 1996 to 18,000 in 2010, leading to an increase in annual nominal-dollar investment in non-associated gas drilling from $12.8 billion in 1996 to $26 billion by 2010. To meet these challenges, the supply sector must be able to realize investment returns that will support adequate production, gain access to public land for oil and gas supply development, achieve rational royalty policies and advance exploration and production technologies.

— DEMAND GROWTH —

End-use markets must have gas supplies at favorable prices, provide improved end-use technologies, promote fuel-neutral air quality policies and foster a pro-competitive regulatory process.

Failure to meet these challenges will delay or cancel the needed pipeline and storage construction and drilling activity, constrain gas supplies, raise prices and slow the growth of the natural gas market. Prospective gas users could turn to other fuels. And because gas-burning equipment typically lasts for several decades, potential sales could be lost for years to come.

## How The Study Was Done

### Analysis

Uncertainties inherent in all energy market forecasts dictate the use of scenarios to describe how a 30 Tcf U.S. gas market might evolve as early as 2010.

This study presents four cases that were created by matching two demand scenarios against two supply scenarios. In one demand scenario, the primary driver is high economic growth while in the second demand scenario early retirement of nuclear power plants and environmental restrictions on coal use accelerate the increase in gas use for the generation of electric power. The two supply scenarios differ in terms of the regional mix of incremental gas supplies: The first assumes substantial growth in Gulf Coast area production; the second relies on Rocky Mountain sources.

### Methodology

The four cases were analyzed using Energy and Environmental Analysis Inc.'s Gas Market Data and Forecasting System (STM), a forecasting model that solves for monthly gas production, storage activity, pipeline flows, end-use consumption and prices at locations in the U.S., Canada and at the Mexico / U.S. border. The model helped determine the new pipeline and storage infrastructure that would be economically justified by the market conditions described by the four cases.

### Market Structure

The assumption was that market forces increasingly would substitute for regulation in determining the construction of new facilities. Therefore, new gas pipeline was projected to be added when annual average regional basis differentials equaled or exceeded the cost of capacity expansions on any given pipeline corridor. Likewise, seasonal storage capacity was expanded in a region only when the weighted average price differential in injection vs. withdrawal periods met or exceeded the cost of new storage capacity.

# 2. Introduction

## Expectations For Market Growth

A number of energy market forecasts point toward a 34 percent increase in annual natural gas consumption in the United States from 22.4 Tcf in 1997 to 30 Tcf by 2010 or shortly thereafter. Exhibit 2-1 shows recent projections of natural gas consumption in the United States for the years 2010 and 2015 along with actual consumption in the year 1997. The projection from the 1999 Edition of the Gas Research Institute (GRI) Baseline shows total U.S. consumption at 28.2 Tcf in 2010 and 31.3 Tcf in 2015. The 1999 Annual Energy Outlook (AEO) from the Department of Energy's Energy Information Administration (EIA) presented several projections of U.S. energy demand. The AEO base or "reference" case and two sensitivities based on lower and higher economic growth are shown in Exhibit 2-1. The range from the AEO for 2010 is 26.3 Tcf to 29.65 Tcf and for the year 2015 is 28.4 Tcf to 33.0 Tcf. Also shown in Exhibit 2-1 are a few other natural gas market projections. The American Gas Association (AGA) projects a total gas market of 31 Tcf in 2015, while forecasting firms WEFA and DRI anticipate markets of 30.1 and 28.5 Tcf respectively.

In all of the forecasts, the power generation sector shows the largest absolute growth and the largest percent annual growth. On average, power generation is expected to make up about 4.5 Tcf or 60 percent of the 7.6 Tcf growth needed to reach a 30 Tcf U.S. gas market. Gas is expected to be the fuel of choice for most new power generation capacity because of the cleanliness, high efficiency and low initial cost of new combined cycle gas turbines. Investors building new powerplants in restructured electricity markets will choose gas-fired units not only because they are expected to be the lowest cost way to generate electricity, but because they reduce risks in that they can

**Exhibit 2-1 Projected U.S. Gas Demand By Sector**
BCF/YEAR

| | | 1997 Actual* | GRI 99 | AEO 99 Reference | AEO 99 Low Growth | AEO 99 High Growth | AGA | WEFA | DRI |
|---|---|---|---|---|---|---|---|---|---|
| **Projected 2010** | Residential | 5,187 | 5,464 | 5,360 | 5,160 | 5,570 | 6,087 | — | — |
| | Commercial | 3,148 | 3,685 | 3,730 | 3,650 | 3,810 | 3,786 | — | — |
| | Industrial | 9,115 | 10,664 | 9,460 | 9,010 | 9,900 | 10,350 | — | — |
| | Power Gen | 2,954 | 5,697 | 6,690 | 5,880 | 7,470 | 5,990 | — | — |
| | Other | 1,993 | 2,698 | 2,770 | 2,640 | 2,900 | 2,728 | — | — |
| | **Total** | **22,397** | **28,209** | **28,010** | **26,340** | **29,650** | **28,942** | **—** | **—** |
| **Projected 2015** | Residential | — | 5,659 | 5,610 | 5,310 | 5,900 | 6,230 | 5,700 | 5,790 |
| | Commercial | — | 3,910 | 3,860 | 3,730 | 3,970 | 4,010 | 3,510 | 3,550 |
| | Industrial | — | 11,320 | 9,870 | 9,200 | 10,550 | 10,840 | 9,920 | 8,990 |
| | Power Gen | — | 7,186 | 8,420 | 7,330 | 9,340 | 6,770 | 8,520 | 7,550 |
| | Other | — | 3,201 | 3,050 | 2,850 | 3,230 | 3,140 | 2,470 | 2,640 |
| | **Total** | **—** | **31,276** | **30,810** | **28,420** | **32,990** | **30,990** | **30,120** | **28,520** |

* 1997 consumption represents "real time consumption" adjusted to account for billing lags, and differs from the EIA consumption estimate of 22.0 Tcf.

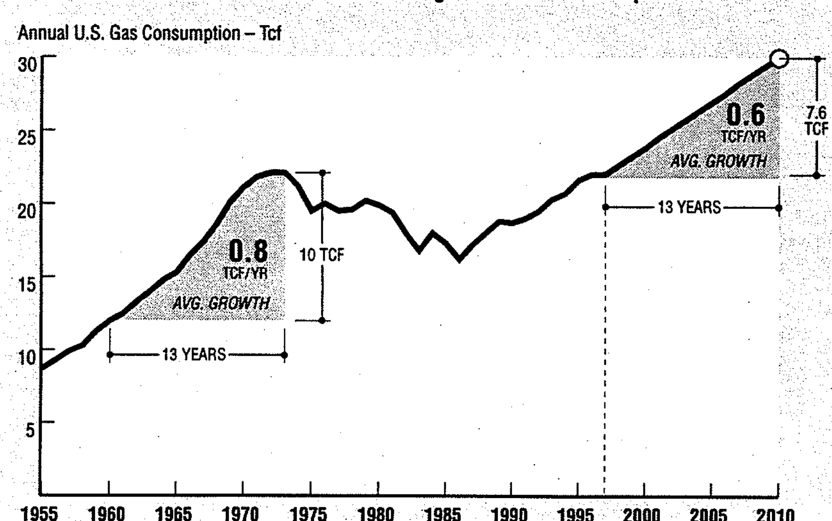
be built quickly and in small sizes allowing for faster reaction to changes in the market.

The industrial sector contributes the next largest portion of the gas demand increase expected by forecasters. On average, the industrial sector is expected to add about 1.0 Tcf of the 7.6 Tcf growth required for a 30 Tcf market. The next largest increases in end-use markets are expected to come from the commercial and residential sectors, each of which is anticipated to grow about 0.6 Tcf. The remaining portion of growth to a 30 Tcf market (0.9 Tcf) is made up of lease and plant gas use and pipeline fuel.

## Historical Perspective On U.S. Gas Markets

Although a 7.6 Tcf increase in annual gas consumption to reach a 30 Tcf annual market is large, it is not unprecedented. Exhibit 2-2 shows the historical U.S. gas consumption and the trajectory needed to reach 30 Tcf by the year 2010. Between 1960 and 1973, U.S. gas consumption grew from 12.0 Tcf per year to 22.1 Tcf per year, a gain of 10.1 Tcf. This was a growth rate of 4.8 percent per year and an absolute average growth of 0.8 Tcf each year. In contrast, a trajectory from 1997 consumption of 22.4 Tcf to 30 Tcf in 2010 is a growth rate of 2.4 percent per year and an absolute growth of 0.6 Tcf each year.

**Exhibit 2-2 The 30 Tcf Challenge In Historical Perspective**




The regulatory and market environments in which the future 30 Tcf market will emerge will be quite different from those in the earlier years of the gas industry and may pose some unprecedented challenges. In the 1950s and 1960s U.S. gas markets were highly regulated and market risks to investors in new pipeline and storage facilities were minimal. Pipelines typically had long-term contracts with both gas producers and local distribution companies, who purchased transportation (and often storage) services along with the gas. Regulations established wellhead prices for interstate commerce as well as the rates charged for pipeline and storage services. With rare exceptions, end users had to purchase gas from local distribution companies or directly from pipelines at regulated rates that were largely unresponsive to changes in supply and demand.

Over the last 20 years or so, the natural gas business has evolved in a manner in which regulations have played a decreasing role and market forces have increased in influence, adding risk to market participants. This process began with wellhead prices, moved to transportation and storage services, and is gaining ground among services provided by local distribution companies. Often, large industrial customers were the first to benefit from these changes, followed by smaller volume customers. The results of these changes generally have been very favorable to the gas industry, as the market stagnation caused by wellhead price control and other restrictive regulations has given way to steady market growth. Today, there are more customers using more natural gas than at any time in U.S. history.

## Challenges Of The 30 Tcf Target By 2010

Several important concerns related to a 30 Tcf future exist among the gas industry and its customers. These concerns involve a variety of regulatory, market and technical uncertainties and can be summarized into the following broad questions:

### 1 How Much Infrastructure Will Be Needed And What Will It Cost?

The pipeline and storage infrastructure construction for the expected 7.6 Tcf increase in gas consumption is expected to be substantial. Will it prove to be comparable to the efforts made in the 1950s and 1960s and to the more recent infrastructure construction undertaken by the U.S. gas industry to supply the growing market since the mid-1980s? Do adequate capabilities exist within pipeline contractors and equipment manufacturers to support the construction of the needed infrastructure?

### 2 Will The Risks Of New Infrastructure Construction Be Properly Shared?

The downside of the growing influence of market forces in the gas industry has been added risk to market participants. Companies building new pipelines will not have 20 years worth of gas supplies lined up before the pipe is built, will not have sale or transportation contracts covering most of the pipeline's depreciable life and will have no assurance that they will recover costs through regulated rates. Instead, the market forces of supply and demand at either end of the pipe and competitive circumstances on other pipelines serving the same markets largely will determine how much gas will flow and at what rate. Will the needed infrastructure investments be made within this uncertain market and regulatory environment?

### 3 What Will New Gas Customers Be Willing To Pay?

The largest growth in natural gas markets will be for power generation, which itself is going through a major restructuring. New power generators will compete fiercely against each other, will be very sensitive to fuel price, and may be reluctant to enter into long-term wellhead and transportation service contracts. Can gas be supplied to the power generation and other sectors at prices that will allow those markets to grow as forecast?

### 4 Will Wellhead Gas Supplies Be Forthcoming At Reasonable Prices?

In the mid-1950s when the U.S. gas market was in its rapid-growth phase, U.S. gas reserves were more than 250 Tcf and the reserve-to-production ratio was about 28 to 1. At the end of 1997 U.S. gas reserves were about 167 Tcf and the R/P ratio was less than 9 to 1. Can U.S. gas reserves and production keep pace with growing gas demand?

### 5 Who Will Champion Natural Gas?

With the restructuring of the natural gas and electric sectors and the "convergence" of the two energy sources — particularly for the purposes of energy marketing — much of the traditional gas-directed R&D, commercialization and marketing activity has been reduced. Will gas markets be able to grow to their full extent without such strong pushes from the gas industry itself?

## Objectives Of This Study

Studies of natural gas markets usually focus on the production of gas at the wellhead and gas competitiveness in end-use markets. Less attention is paid to the market for transportation and storage services necessary to deliver gas economically to the marketplace. The purpose of this study is to fill that gap by estimating those infrastructure requirements. This study will review recent findings regarding supply availability and market potential, but will not independently research those subjects. In summary, this study will:

- Create realistic scenarios for a 30 Tcf U.S. market by 2010;
- Estimate the incremental gas pipeline and

storage infrastructure needed to support that market; and

- Assess the challenges that the gas industry faces in providing that infrastructure and the other items needed for continued market growth.

## Outline Of Report

The next part of this report (Section 3) presents highlights of the modeling methodology used in this study. Sections 4 and 5 present key demand and supply assumptions. Section 6 discusses the current gas transmission and storage infrastructure in the United States and expected costs for expansions. Section 7 describes the expected future market environment and Section 8 presents the key modeling results of the four cases. Conclusions from the study and challenges faced by the gas industry are discussed in Section 9.

Because of the great interest in incremental gas supplies for a 30 Tcf market, Appendix A presents details on the current status and future prospects for Canadian Atlantic gas supplies.

# 3. Methodology For Study

## Scenario Approach

The two most important elements of uncertainty are where the needed gas will come from and the location and type of gas demand for the 30 Tcf target. To deal with these uncertainties, this study presents two supply and two demand cases and discusses the resulting four possible scenarios created by combining those cases.

**Exhibit 3-1 Construction Of Cases**

| | | Demand Scenarios | |
|---|---|---|---|
| | | High Economic Growth | Power Generation Restrictions |
| Supply Scenarios: Major Source Of Incremental Gas Supply | Gulf Coast | Case #1 | Case #2 |
| | Rockies | Case #3 | Case #4 |

Each of these supply/demand balances has different transportation flow patterns and seasonal gas requirements. As shown in Exhibit 3-1, one supply case assumes that a significant portion of additional gas supplies will come from the Gulf Coast area of the U.S., while the second case will rely more heavily on incremental supplies from the U.S. Rockies. One demand case assumes rapid economic growth in the U.S. with increasing gas demand coming from all sectors and the second demand case assumes lower economic growth and faster retirements of nuclear powerplants, thus concentrating more of the growth in gas demand in power generation.

## Modeling Approach

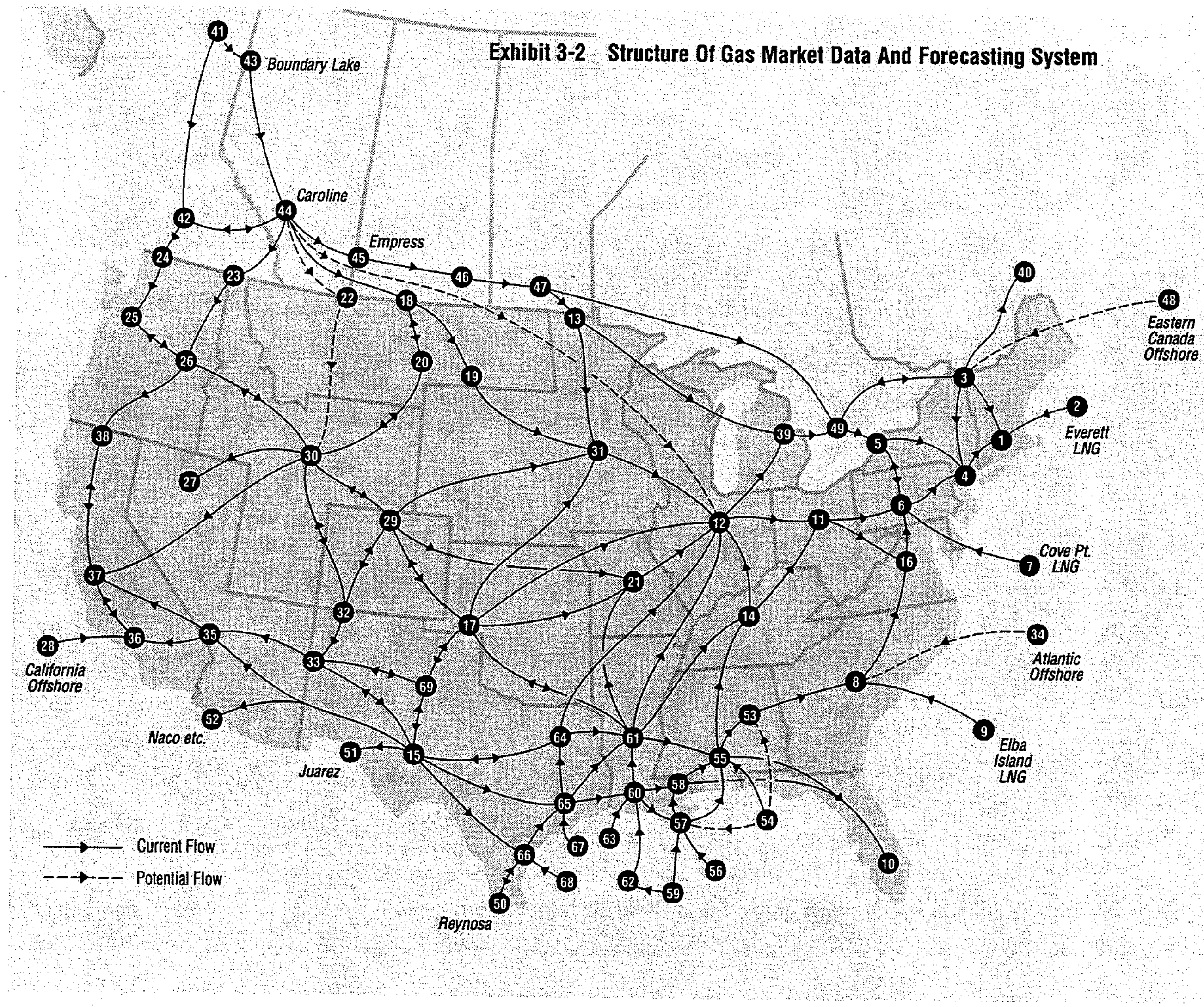
EEA used its Gas Market Data and Forecasting System (STM) to investigate the four scenarios. This model simulates monthly gas markets within the United States and Canada. The STM represents gas supplies, storage activity, demands and prices in approximately 69 areas or nodes and gas transmission capacity, flows and value of transmission services along roughly 142 pipeline corridors. A map of the nodes and corridors is shown as Exhibit 3-2. The legend for this map is shown in Exhibit 3-3.

The model portrays monthly gas throughput and pipeline load factors in the post Order 636 gas market. Importantly, the model reflects the market value and market price for monthly transportation services that determine gas prices and gas basis differentials in today's gas market. The nature of the pipeline network in the model allows model users to evaluate the impact of new pipeline and storage facilities on the flow of gas throughout North America.

## Procedure For Estimating Infrastructure Requirements

An important output from the four STM cases is the amount of new pipeline capacity needed on each corridor and the amount of new storage capacity needed at each storage node. EEA has developed cost estimates for future expansions on each of the 142 gas pipeline corridors included in the model. These include average pipeline and compressor requirements for every increment of additional capacity added in each construction case. These "generic" cost factors are described in Section 6 of this report. EEA projected transmission pipe and compressor requirements for each of the four scenarios by multiplying the needed capacity of each corridor times these fac-

**Exhibit 3-2 Structure Of Gas Market Data And Forecasting System**




tors. Similar factors were developed for gas storage and were used to estimate pipe and compressor requirements for incremental storage capacity.

The STM was run iteratively to determine what new pipeline and storage infrastructure would be economically justified by the market conditions described by the four cases. The operating premise was that market forces increasingly would substitute for regulation in determining the construction of new facilities. Therefore, new gas pipeline was projected to be added when annual average regional basis differentials equaled or exceeded the cost of capacity expansions on any given pipeline corridor. Likewise, seasonal storage capacity was expanded in a region only when the weighted average price differential in injection versus withdrawal periods met or exceeded the cost of new storage capacity.

For the purpose of modeling decisions to build new pipeline it was assumed that investors would need to see the regional basis differential exceed the cost of that new pipeline capacity as measured by the pipeline's 10-year levelized cost of service. The financial assumptions underlying the decisions to build new pipeline capacity are shown in Exhibit 3-4. The example is for a $1.0 billion pipeline that is expected to transport 300 bcf of gas each year. Given the assumptions contained on the upper half of the exhibit — most notably a return on equity of 13 percent, a cost of debt of 7.5 percent and a 50/50 debt to equity ratio — the first annual revenue requirement under traditional cost-of-service rate making would be $199 million or $0.66 per Mcf of gas. The cost levelized over the first 10 years would be $178 million ($0.59 per Mcf). Stated another way, the capital recovery factor used in the basis comparison (including 2.5 percent non-fuel operating and maintenance costs) was 0.178. The cost of fuel use for any pipeline expansion was the fuel loss factor (based on distance) times the gas price forecast by the model.

The economic decisions to build new seasonal storage capacity were made on a similar basis. The capital cost of new storage capacity was translated into a dollar per Mcf cost-of-service rate. This was then added to fuel losses and holding costs of the gas in storage to arrive at a total cost for seasonal storage from new capacity. When the weighted average cost of gas during the withdrawal season minus the weighted average cost during the injection season exceeded the cost of new storage capacity, new capacity was added.

This modeling procedure made new pipeline capacity compete against new seasonal storage capacity. The model tended to build new pipeline capacity to supply incremental gas demand with a high annual load factor. The model added new storage to supply only that portion of incremental demand with high winter peaks and low annual load factors.

**Exhibit 3-3 Key To STM Node Designations**

| NODE | NAME | SUPPLY | DEMAND | STORAGE |
|---|---|---|---|---|
| N1 | New England | | ME, NH, VT, MA, CT, RI | |
| N2 | Everett LNG | LNG | | |
| N3 | Phillipsburg / Cornwall Impts. | | | |
| N4 | New York/ New Jersey | | E. NY, NJ | |
| N5 | Niagara Impts./ West'n New York | NY | W. NY | NY |
| N6 | Pennsylvania/ Delaware | PA | PA, DE | PA |
| N7 | Cove Point LNG | LNG | | |
| N8 | South Atlantic | | NC, SC, GA | |
| N9 | Elba Island LNG | LNG | | |
| N10 | Florida | FL | FL | |
| N11 | Appalachia | OH, WV | OH, WV | OH, WV |
| N12 | Midwest | IN, IL | IN, IL, WI | IN, IL |
| N13 | Emerson Imports | | | |
| N14 | Tennessee, Kentucky | TN, KY | TN, KY | TN, KY |
| N15 | Southwest Texas | Permian Basin | SW. TX, E. NM | SW. TX, E. NM |
| N16 | Mid Atlantic | VA, MD | VA, MD, DC | MD |
| N17 | Mid Continent | North Anadarko Basin | OK, KS | OK, KS |
| N18 | Monchy Imports | | | |
| N19 | Great Plains | Great Plains Coal Gasification | | |
| N20 | Montana/ North Dakota | Williston Basin | MT, ND | MT |
| N21 | Missouri | MO | MO | MO |
| N22 | Wild Horse Imports | | | |
| N23 | Kingsgate Imports | | | |
| N24 | Huntingdon Imports | | | |
| N25 | Pacific Northwest | OR | OR, WA | OR |
| N26 | NPC/PGT Hub | | | |
| N27 | North Nevada | N. NV | N. NV | |
| N28 | Pacific Offshore | Pacific Offshore | | |
| N29 | Colorado | S. Forerange, DJ Basin | CO | CO |
| N30 | Opal/ Kern River | N. Forerange; Overthrust Belt | WY, UT, ID | WY, UT |
| N31 | Central | | IA, NE, SD, MN | IA, NE, MN |
| N32 | San Juan Basin | San Juan Basin | | |
| N33 | EPNG/TW | | W. NM | W. NM |
| N34 | Atlantic Offshore | Atlantic Offshore | | |
| N35 | Arizona, South Nevada | AZ, S. NV | AZ, S. NV | |
| N36 | Southern California | S. CA | S. CA | S. CA |
| N37 | EOR Region | | EOR Region | EOR Region |
| N38 | PGE | N. CA | N. CA | N. CA |
| N39 | Michigan | MI | MI | MI |
| N40 | Quebec | | Quebec | Quebec |
| N41 | British Columbia (N) | British Columbia | | British Columbia |
| N42 | British Columbia (S) | | British Columbia | |
| N43 | Boundary Lake | | | |
| N44 | Caroline | Alberta | Alberta | Alberta |
| N45 | Empress | | | |
| N46 | Saskatchewan | Saskatch. | Saskatch. | Saskatch. |
| N47 | Manitoba | Manitoba | Manitoba | |
| N48 | Eastern Canada | E. Canada | Atlantic | Quebec |
| N49 | Ontario | Ontario | Ontario | Ontario |
| N50 | Reynosa Imports/Exports | | | |
| N51 | Juarez Exports | | | |
| N52 | Naco Exports | | | |
| N53 | North Alabama | N. AL | N. AL | |
| N54 | Alabama Offshore | Norphlet and Viosca Knoll | | |
| N55 | Mississippi and Alabama | MS, S. AL | MS, S. AL | MS |
| N56 | East Louisiana Offshore (Peninsula) | Grand Isle, South Pass, Desoto Canyon, & MS Canyon | | |
| N57 | Louisiana Peninsula | Louisiana Peninsula area | SE. LA | SE. LA |
| N58 | Eastern Hub | | | |
| N59 | East Louisiana Offshore | West Delta, Ewing Bank, Timbalier, & Green Canyon | | |
| N60 | Central Louisiana Hub (Henry Hub) | S. LA Onshore, Lake Charles LNG | S. LA (except SE. LA) | S. LA (except SE. LA) |
| N61 | Northern Louisiana Hub | N. LA, AR | N. LA, AR | N. LA, AR |
| N62 | Central Louisiana Offshore | Ship Shoal, Eugene Is., S. Marsh, Vermilion, Garden Banks, & E. Cameron | | |
| N63 | West Louisiana & East Texas Offshore | West Cameron & HIOS area | | |
| N64 | Northeast TX (Carthage Area) | NE. TX | NE. TX (Dallas) | NE. TX |
| N65 | East Texas (Katy Hub & Houston Ship Channel) | E. TX | E. TX (Houston) | E. TX (except NE. Texas) |
| N66 | South Texas | S. TX | S. TX | S. TX |
| N67 | Houston/Galveston Offshore | Galveston Offshore | | |
| N68 | South Texas Offshore | S. TX Offshore | | |
| N69 | Northwest Texas | So. Anadarko Basin | NW. TX | NW. TX |

## Exhibit 3-4 Pipeline Cost Of Service Calculation

( For Illustrative Purposes Only )

1998$

**ASSUMPTIONS:**

Total Capital Costs (millions) . . . . . . . . . . . = $1,000
Ratio Of Equity To Total Capital . . . . . . . . . = 0.50
A.T. Nominal Return On Equity . . . . . . . . . = 13.0%
B.T. Nominal Cost Of Debt . . . . . . . . . . . . = 7.5%
Useful Life For Rate Making . . . . . . . . . . . = 30
Inflation Rate . . . . . . . . . . . . . . . . . . . . . = 2.5%

Federal And State Income Tax Rate . . . . . = 37.0%
Annual O&M, Insur., Property Tax (millions) = $25
Annual Throughput (bcf) . . . . . . . . . . . . . = 300

**CALCULATED:**

Average B.T. Nominal Return . . . . . . . . . . = 14.07%
Average B.T. Real Return . . . . . . . . . . . . . = 11.29%

**Annual Revenue Requirement In Nominal Million Dollars**

| Year Of Operation | Annual Deprec. | Net Plant | Cum. Deferred Taxes | Rate Base | Interest On Debt | Return On Equity | Tax On Equity Return | Oper. & Maint. Costs | Total Revenue Requir. | Revenue Requir. | Inflation Index | Real Revenue Requir. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($) | ($) | ($) | ($) | ($) | ($) | ($) | ($) | ($) | ($/MCF) | | ($/MCF) |
| 1 | 33 | 1,000 | 0 | 1,000 | 38 | 65 | 38 | 25 | 199 | 0.66 | 1.00 | 0.66 |
| 2 | 33 | 967 | 6 | 961 | 36 | 62 | 37 | 26 | 194 | 0.65 | 1.03 | 0.63 |
| 3 | 33 | 933 | 29 | 904 | 34 | 59 | 35 | 26 | 187 | 0.62 | 1.05 | 0.59 |
| 4 | 33 | 900 | 48 | 852 | 32 | 55 | 33 | 27 | 180 | 0.60 | 1.08 | 0.56 |
| 5 | 33 | 867 | 64 | 802 | 30 | 52 | 31 | 28 | 174 | 0.58 | 1.10 | 0.52 |
| 6 | 33 | 833 | 78 | 756 | 28 | 49 | 29 | 28 | 168 | 0.56 | 1.13 | 0.49 |
| 7 | 33 | 800 | 88 | 712 | 27 | 46 | 27 | 29 | 162 | 0.54 | 1.16 | 0.47 |
| 8 | 33 | 767 | 98 | 669 | 25 | 43 | 26 | 30 | 157 | 0.52 | 1.19 | 0.44 |
| 9 | 33 | 733 | 107 | 626 | 23 | 41 | 24 | 30 | 152 | 0.51 | 1.22 | 0.42 |
| 10 | 33 | 700 | 117 | 583 | 22 | 38 | 22 | 31 | 147 | 0.49 | 1.25 | 0.39 |
| 11 | 33 | 667 | 126 | 540 | 20 | 35 | 21 | 32 | 141 | 0.47 | 1.28 | 0.37 |
| 12 | 33 | 633 | 136 | 497 | 19 | 32 | 19 | 33 | 136 | 0.45 | 1.31 | 0.35 |
| 13 | 33 | 600 | 146 | 454 | 17 | 30 | 17 | 34 | 131 | 0.44 | 1.34 | 0.32 |
| 14 | 33 | 567 | 155 | 412 | 15 | 27 | 16 | 34 | 126 | 0.42 | 1.38 | 0.30 |
| 15 | 33 | 533 | 165 | 369 | 14 | 24 | 14 | 35 | 121 | 0.40 | 1.41 | 0.28 |
| 16 | 33 | 500 | 174 | 326 | 12 | 21 | 12 | 36 | 115 | 0.38 | 1.45 | 0.27 |
| 17 | 33 | 467 | 173 | 294 | 11 | 19 | 11 | 37 | 112 | 0.37 | 1.48 | 0.25 |
| 18 | 33 | 433 | 160 | 273 | 10 | 18 | 10 | 38 | 110 | 0.37 | 1.52 | 0.24 |
| 19 | 33 | 400 | 148 | 252 | 9 | 16 | 10 | 39 | 108 | 0.36 | 1.56 | 0.23 |
| 20 | 33 | 367 | 136 | 231 | 9 | 15 | 9 | 40 | 106 | 0.35 | 1.60 | 0.22 |
| 21 | 33 | 333 | 123 | 210 | 8 | 14 | 8 | 41 | 104 | 0.35 | 1.64 | 0.21 |
| 22 | 33 | 300 | 111 | 189 | 7 | 12 | 7 | 42 | 102 | 0.34 | 1.68 | 0.20 |
| 23 | 33 | 267 | 99 | 168 | 6 | 11 | 6 | 43 | 100 | 0.33 | 1.72 | 0.19 |
| 24 | 33 | 233 | 86 | 147 | 6 | 10 | 6 | 44 | 98 | 0.33 | 1.76 | 0.19 |
| 25 | 33 | 200 | 74 | 126 | 5 | 8 | 5 | 45 | 96 | 0.32 | 1.81 | 0.18 |
| 26 | 33 | 167 | 62 | 105 | 4 | 7 | 4 | 46 | 94 | 0.31 | 1.85 | 0.17 |
| 27 | 33 | 133 | 49 | 84 | 3 | 5 | 3 | 48 | 93 | 0.31 | 1.90 | 0.16 |
| 28 | 33 | 100 | 37 | 63 | 2 | 4 | 2 | 49 | 91 | 0.30 | 1.95 | 0.16 |
| 29 | 33 | 67 | 25 | 42 | 2 | 3 | 2 | 50 | 89 | 0.30 | 2.00 | 0.15 |
| 30 | 33 | 33 | 12 | 21 | 1 | 1 | 1 | 51 | 87 | 0.29 | 2.05 | 0.14 |

| | Total Revenue Requir. ($) | Revenue Requir. ($/MCF) | Real Revenue Requir. ($/MCF) |
|---|---|---|---|
| **5 Year Levelized Value =** | **188** | **0.63** | **0.60** |
| **10 Year Levelized Value =** | **178** | **0.59** | **0.54** |
| **20 Year Levelized Value =** | **167** | **0.56** | **0.48** |
| **30 Year Levelized Value =** | **163** | **0.54** | **0.46** |

# 4. Demand Scenarios

## Introduction

There are several drivers to natural gas demand. The most important are the pace of economic activity, the price and availability of alternative fuels, the quantity of power generation from nuclear powerplants, and environmental and other regulations that might affect fuel competition. This section presents the key assumptions chosen to construct the two 30 Tcf demand scenarios and introduces the basic U.S., Canadian and Mexican gas demand levels used in the cases.

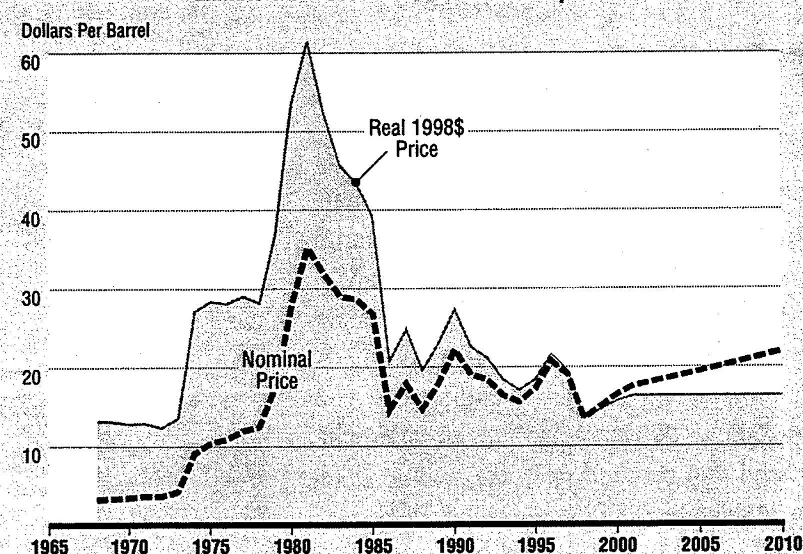
## Oil And Coal Prices

Oil prices are important to gas markets in two respects. First, gas competes against residual and distillate fuel oils for certain end-use markets. To the extent oil prices are low, end users are more likely to switch away from gas when gas prices rise. Second, the price of oil affects the exploration and development of natural gas resources. Gas often is found along with oil so the incentive to look for one often leads to greater discoveries of both. Also, about 15 percent of the heat content of raw nonassociated gas production is in the form of natural gas liquids (ethane, propane, butanes and pentanes plus), with prices which closely track crude oil. This means that the incentive to develop gas is in some measure tied to oil prices.

Exhibit 4-1 shows the refiners' average cost of crude (RACC) assumed for all cases presented here. In nominal terms, the oil price scenario has prices recovering from about $13.00 per barrel in 1998 in the next two years and then growing with inflation (at 2.5 percent per year) to $22.00 per barrel in nominal dollars by 2010. In real dollars, the projected RACC price in 2010 is about $16.40 per barrel in 1998 dollars.

Coal prices for all cases are assumed to rise one percent per year in nominal dollars. This means that real coal prices are declining at more than one percent per year.

**Exhibit 4-1 U.S. RACC Price Assumptions**




## Economic Growth

The rate of economic activity affects the pace at which new factories are built and industrial equipment is installed, the rate at which new commercial floor space is added and the number of new housing units that are built. These activities affect gas demand directly through the installation of new gas burning equipment and appliances and indirectly by increasing electricity demand, which, in turn leads to a greater need for new gas-fired power generating equipment.

Mexican gas demand is expected to grow at a rate of about 5.6 percent per year. More than half of the growth will take place in the power generation sector, which is being restructured in Mexico to allow private investment in new power plants. As in the United States, most of these power plants are expected to be gas-fired. Mexico also plans to convert much of its oil-fired capacity to gas.

**Exhibit 4-7 North American Gas Demand**
BCF/YEAR

| | | Cases #1, #3 | | Cases #2, #4 | |
|---|---|---|---|---|---|
| | 1997 | 2010 | Growth% | 2010 | Growth% |
| U.S. | 22,397 | 30,383 | 2.4% | 30,272 | 2.3% |
| Canada | 2,592 | 3,595 | 2.6% | 3,482 | 2.3% |
| Mexico | 1,213 | 2,464 | 5.6% | 2,464 | 5.6% |
| **Total** | **26,201** | **36,442** | **2.6%** | **36,217** | **2.5%** |

## The North American Gas Market

The year 2010 gas market in the U.S., Canada and Mexico is summarized in Exhibit 4-7. In an environment in which the U.S. market grows to 30 Tcf by 2010, gas demand is expected to grow in these countries at a combined rate of about 2.5 percent per year. The total North American gas market in 2010 would be 36.2 to 36.4 Tcf in size. The U.S. represents about 83 percent of that market.

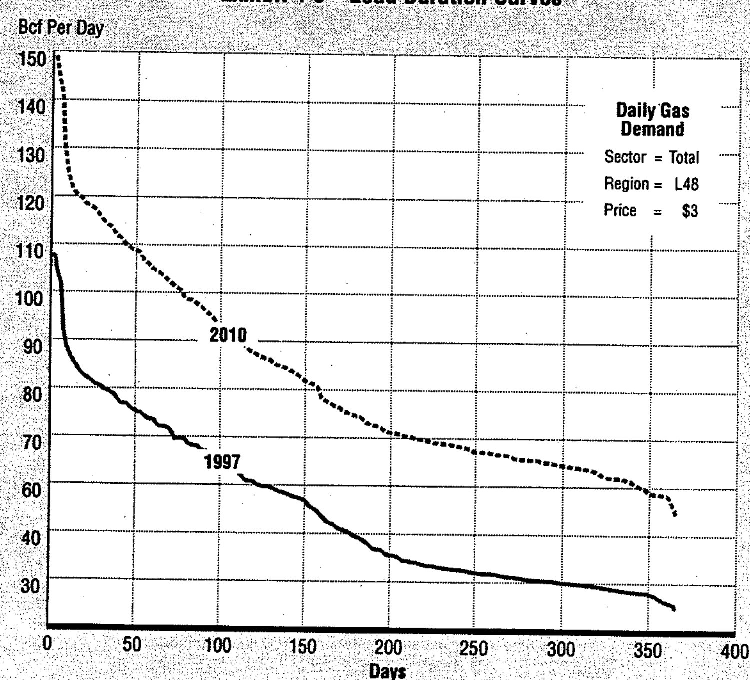
## U.S. Peak Gas Demand

In addition to forecasting monthly gas demand and prices, the STM can be used to analyze daily gas demand in future years. The daily gas demand estimates can be analyzed to determine peak-day demands and gas demand "load duration curves."

Exhibit 4-8 shows the coincident load duration curve for the Lower 48 U.S. for the year 1997 and the how that same curve would look in the year 2010 under the "high economic growth" assumptions *if 1997 weather patterns were repeated exactly.* The growth in peak demand is important because supply capacity (pipeline, storage or peakshaving) must be built to accommodate peak-day requirements.

The coincident daily peak U.S. demand would grow from about 110 bcfd to about 150 bcfd in 2010 — a gain of 40 bcfd excluding the effects of potential fuel switching. If fuel switching is considered, the gain in peak-day demand would be as little as 20 bcfd. By comparison, a 7,500 bcf per year gain in end-use consumption would result in an increase in average daily demand of 20.5 bcfd. The non-switchable peak grows less than the average consumption because new combined cycle powerplants, which make up a large part of the demand growth, are assumed to be capable of burning distillate fuel oil and, thus could be switched off gas in the coldest winter days.

**Exhibit 4-8 Load Duration Curves**



# 5. Supply Assumptions

## Introduction

Much of the current debate about the feasibility of reaching a 30 Tcf gas market in the United States centers on whether adequate gas supplies will be available at acceptable prices. At various times and from various sources concerns have been raised about the size of the underlying natural gas resource base, the cost of getting the gas, the desire of the domestic oil and gas industry to invest in the United States *vs.* overseas and the potential upstream infrastructure constraints on drilling rigs, other E&P services and trained personnel. The purpose of this chapter is to review — but not try to resolve — some elements of the debate and to present a set of reasonable assumptions to be used in this study's forecasts of pipeline and storage infrastructure needs.

## Historical Natural Gas Production And Reserves

Exhibit 5-1 shows U.S. natural gas production and reserves from 1960 to 1997. U.S. gas reserves peaked at 293 Tcf in 1967, after which they declined until 1988. Since then gas reserves have remained in the range of 162 to 168 Tcf.

U.S. gas production peaked in 1973. Production then trended downward because:

- Price controls restricted supplies and led to moratoria on new gas hookups;
- Economic slowdowns and conservation efforts brought on by the first oil crisis in 1974 reduced total energy markets;
- The "rust belt" emerged in the Midwest reducing industrial energy markets for gas; and
- The market share of gas in power generation was squeezed by the growth of nuclear power and mandated restrictions on gas use.

After these effects worked through the system, gas demand and production reversed course after 1986 and except for the impact of weather, have grown steadily since then.

**Exhibit 5-1 U.S. Gas Production And Reserves**

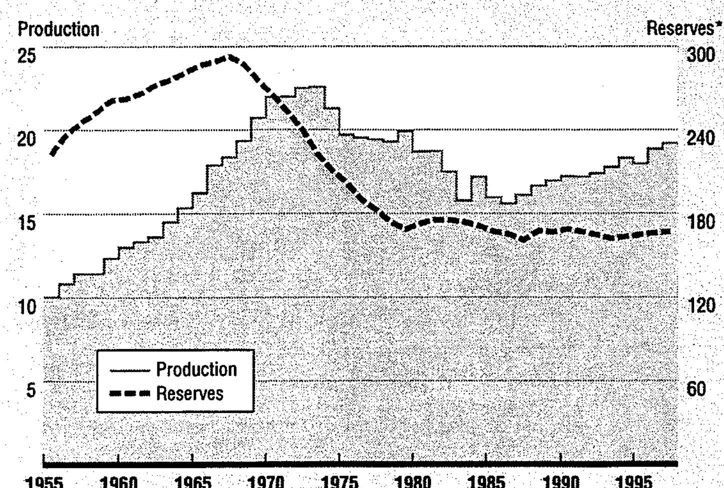



**Exhibit 5-2 Lower-48 Gas Resource Comparisons**
TOTAL GAS — TCF

| | NPC Study | GRI Baseline | USGS | PGC |
|---|---|---|---|---|
| | 1992 | 1998 | 1995 | 1997 |
| New Fields | 493 | 880 | 332 | 441 |
| Growth In Old Fields | 236 | 434 | 327 | 158 |
| Coalbed Methane | 97 | 110 | 50 | 75 |
| Tight Gas | 234 | 234 | 227 | n/a |
| Shale | 57 | 138 | 84 | n/a |
| **Total** | **1,117** | **1,796** | **1,020** | **674** |

* Prudhoe Bay, Alaska gas reserves which were booked in 1971 then removed in 1987 have been removed from all years of the chart to prevent their distortion of trends in the data.

## Resource Base Assessments Of Undiscovered Natural Gas

Exhibit 5-2 shows estimates of undiscovered remaining Lower 48 natural gas resources as determined by the National Petroleum Council in 1992, the U.S. Geological Survey in 1995, the U.S. Potential Gas Agency in 1997 and the Gas Research Institute in 1998. The resources are shown separately for growth in existing fields, new fields and the nonconventional sources of coal bed methane, tight gas and shales. Proven reserves of about 160 Tcf are not in the table. The smallest estimate for which all components are included is the USGS assessment of 1,020 Tcf. The largest estimate is GRI's assessment of 1,796 Tcf. At current rates of production, these estimates of undiscovered gas represent from 55 to 96 years of production.

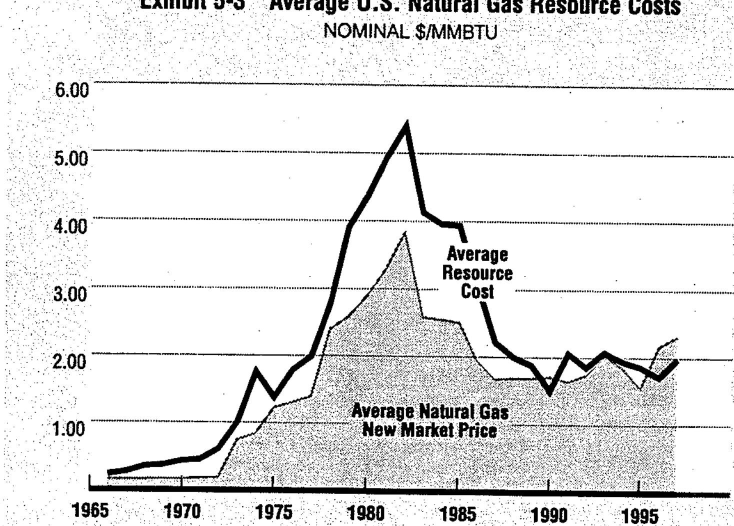
It is important to note that such assessments only include resources that are of a type and location that either is now being exploited or whose exploitation can reasonably be imagined with known technology. The history of resource assessments has shown that as time goes on and more is learned about resources and how to exploit them, the total size of the ultimate resource base (cumulative production, reserves plus undiscovered resources) increases. As an example of how new resources are added over time, Appendix A of this report describes recent supply developments in the Canadian Atlantic, a region that has only recently become part of the North America's natural gas supply outlook.

## Historical Finding Costs And Role Of Technology

Producers will drill new oil and gas wells, recomplete existing wells and enhance production through restimulation or the addition of compression only when expected oil and gas prices are high enough to justify the necessary investments. Expenditures are made for drilling wells, lease acreage, geologic and geophysical services, offshore platforms, lease equipment, well operation and maintenance, financing and taxes. Other important factors influencing upstream economics are the expected success rate of the drilling program, anticipated size of new discoveries, recoveries per well, the time profile of production and the future prices for crude oil, natural gas and natural gas liquids.

These economic factors can be translated into natural gas or crude oil "resource costs," or the minimum price needed to make an investment worthwhile. Exhibit 5-3 shows the estimated nominal-dollar resource cost of gas for average new gas wells drilled in the United States from 1966 to 1997. Resource costs are calculated using actual historical costs and engineering parameters (e.g., success rate, recovery per well) and assume a minimum rate of return of five percentage points above an average AAA corporate bond issued in each year. After reaching a high of $5.40 per MMBtu in 1982, the resource cost of new nonassociated gas fell through 1990 and since then has ranged between $1.75 and $2.05. It should be noted that the costs shown in Exhibit 5-3 are aver-

**Exhibit 5-3 Average U.S. Natural Gas Resource Costs**



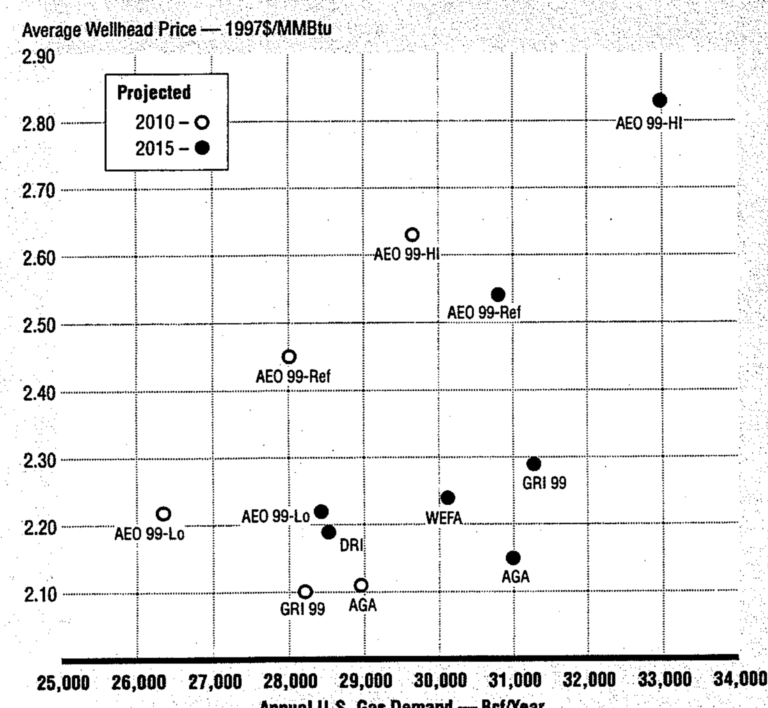
ages and include both low cost reserve additions (such as additions to existing fields) and the higher cost additions (such as from new field exploration).

Exhibit 5-3 also shows the average gas price received each year for production from new wells. These prices reflect regulated pricing through 1982 and, thereafter, market prices. As the exhibit shows, resource costs tend to move in the same direction as prices. This occurs both because producers concentrate on low-cost gas when prices are low but make incremental investments for more expensive gas when prices are high and because the factor costs to producers (e.g., lease acreage, wells) go up and down with oil and gas prices.

In the early years shown in Exhibit 5-3, the prevailing market prices were below the resource costs, indicating that producers were making investments on the expectation of higher prices in the future. In more recent years, prevailing gas prices have been slightly higher than estimated resource costs. This means that the producers' average realized rates of return for marginal gas investments have been close to the rate (five percentage point over AAA corporate bonds) used in the resource cost calculation.

The total decline in resource costs from the 1982 peak to the $1.91 average value for the last five years of data was $3.49 per MMBtu. This was a result of factors that reduced costs by $3.66 and factors that increased costs by $0.17. Fifty-nine percent of the $3.66 reduction was due to increased recovery per well — itself a result of improved technologies and better management practices. Other factors include reduced well and equipment costs (20 percent), lower interest rates (17 percent) and improved drilling success rates (four percent). Reduced value of natural gas liquids was the primary factor that increased costs by $0.17.

**Exhibit 5-4 Projected U.S. Gas Price And Demand**




## Forecasts Of Gas Prices

Exhibit 5-4 shows the projected wellhead prices from the forecasters whose demand estimates were presented earlier. The exhibit shows the size of the projected gas market on the x-axis and the average projected U.S. wellhead gas price in real 1997 dollars per MMBtu on the y-axis. The real-dollar prices consistent with a 30 Tcf market are in the range of $2.10 to about $2.70 per MMBtu. Most of the forecasts fall at the lower end of that range. The significance of this exhibit is that all of the major forecasters envision gas supplies sufficient to satisfy markets near 30 Tcf in size at real wellhead prices that are similar to or slightly above prices seen in recent years.

## Alternative Gas Production Scenarios

To evaluate pipeline and storage infrastructure needs, EEA developed a forecast of lower-48 gas production by region. This was done by creating a "base" deliverability trend for each region that was keyed to certain resource base, technology and cost assumptions. The goal was to construct regional gas production patterns similar to published forecasts such as the GRI baseline and to create a price forecast that fell into the upper end of the range of published forecasts. The upper end of the range was targeted to address concerns that large increases in U.S. gas production would require real price increases over recent levels and to illustrate that the 30 Tcf market could be achieved even under relatively high-cost wellhead supplies. Throughout the simulation of future years, the drilling activity algorithms in the STM modified these base trends to reflect regional price and take results. The results from the model included revised completion activity, deliverability and production trends that reflected the model's regional price forecast.

There were two sets of "base" deliverability trends put into the STM. The first reflected a relatively optimistic view of Gulf of Mexico (GOM) offshore and Gulf Coast onshore production potential. This scenario was used for Cases #1 and #2. A second set of base trends was created with a somewhat more pessimistic view of Gulf of Mexico offshore and Gulf Coast onshore production potential. This scenario, which had more Rocky Mountain production, was used for Cases #3 and #4.

Exhibit 5-5 shows approximate regional production levels achieved in the four cases. The regions shown on the exhibit are aggregations of the 38 regions characterized in the STM. Average U.S. production grows about 2.2 percent per year, with the highest rates of growth expected in the GOM offshore and West regions. As shown in Exhibit 5-5, Canada and Mexico are also assumed to have substantial increases in gas production.

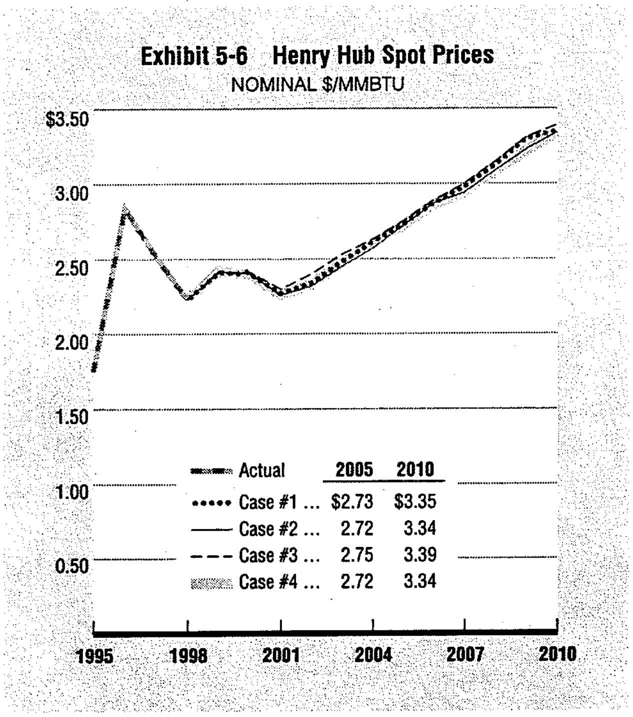
As was shown in Section 4, U.S. gas consumption in 2010 ranges from 30.3 to 30.4 Tcf per year in the four cases. The STM results yield net imports from Canada in 2010 ranging from 4.8 to 4.9 Tcf. In all cases, net exports to Mexico are set at 0.4 Tcf and LNG exports from Alaska to Japan are assumed to be less than 0.1 Tcf. Therefore, net gas imports average about 4.4 Tcf across all of the cases, or about 14 percent of projected 2010 U.S. consumption.

**Exhibit 5-5 Gas Production By Region**
BCF/YEAR

| | | Cases #1, #2 | | Cases #3, #4 | |
|---|---|---|---|---|---|
| | 1997 | 2010 | Growth% | 2010 | Growth% |
| U.S. East | 575 | 673 | 1.2% | 674 | 1.2% |
| U.S. Midwest | 264 | 356 | 2.3% | 356 | 2.3% |
| U.S. Southwest | | | | | |
| Onshore | 9,970 | 11,839 | 1.3% | 11,606 | 1.2% |
| Offshore | 5,432 | 8,599 | 3.6% | 8,274 | 3.3% |
| U.S. West & AK | 3,421 | 4,766 | 2.6% | 5,394 | 3.6% |
| **U.S. Subtotal** | **19,662** | **26,232** | **2.2%** | **26,303** | **2.3%** |
| Canada | 5,328 | 8,419 | 3.6% | 8,381 | 3.5% |
| Mexico | 1,187 | 2,145 | 4.7% | 2,145 | 4.7% |
| **North American Total** | **26,177** | **36,796** | **2.7%** | **36,829** | **2.7%** |

## U.S. Gas Prices

Exhibit 5-6 shows the annual average spot gas prices at Henry Hub resulting from the four cases. The prices are very similar because the total gas demand trajectory is nearly the same for all cases, although the regional and sectoral mixes are different. In nominal dollars, Henry Hub prices are expected to average a 3.3 percent per year increase to about $3.35-




$3.40 per MMBtu in 2010. In real 1998 dollars, this is about $2.50 per MMBtu.

## Implied U.S. Gas Drilling Activity

The forecasted increase in U.S. production to more than 26 Tcf will require an increase in annual gas well completions[2] from an average of about 11,600 in 1995 and 1996 and 14,000 in 1997 to about 18,000 in 2010. This level of activity will lead to an increase in annual nominal-dollar investment in non-associated gas drilling from about $12.8 billion in 1995/96 to about $26 billion by 2010.

2. Completions refers to both new gas wells and new gas completions in existing or sidetracked boreholes (recompletes).

# 6. Transmission and Storage Infrastructure

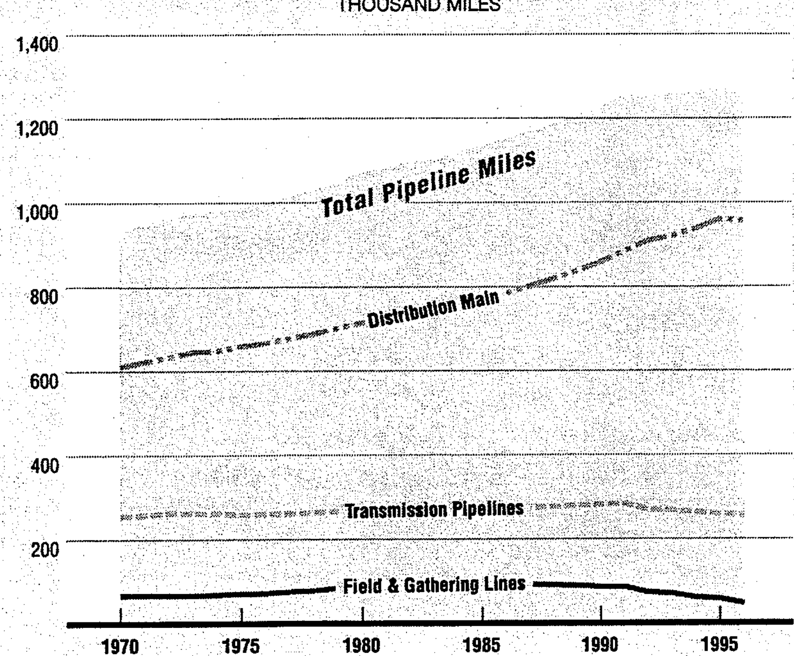
## Existing Gas Pipeline Infrastructure

The U.S. contains approximately 260,000 miles of natural gas transmission pipeline, 185,000 miles of which are owned by interstate pipelines. As is shown in Exhibit 6-1, there are another 50,000 miles of gas gathering line and some 955,000 miles of distribution line owned by the gas utility industry. In total, gas utility gathering, transmission and distribution represent approximately 1.26 million miles of pipe in the United States. The recent reductions in gas gathering line shown in Exhibit 6-1 reflect the spin-off or sale of gathering facilities to non-utility entities.

The U.S. gas transmission infrastructure contains approximately 14 million horsepower of compression. Most of this transmission compression is fueled directly by gas (either with reciprocating engine or turbine prime movers) and the remainder is powered by electricity. As reported by EIA, in 1997 gas use by transmission compressors totaled 712 bcf or 3.2 percent of the 21,979 bcf U.S. gas consumption.

There is no easy way of summarizing into a single statistic the "capacity" of the entire U.S. gas pipeline infrastructure since the ability of the pipeline system to flow gas on any given day depends on where the gas is being produced or withdrawn from storage and where the gas is being consumed. Instead, gas pipeline capacity must be analyzed from the perspective of specific interregional capacities and flows and how they might change in the future. Exhibit 6-2 shows some of the major gas pipeline corridors and their estimated capacity in million cubic feet per day (MMcfd). These corridors are represented in EEA's Gas Market Data and Forecasting System and are each made up of one or more pipelines. The corridors with the largest capacities tend to be those moving gas from the Southwest U.S. (primarily Texas and Louisiana production) to the East and North and corridors moving gas from the Mid-continent (primarily Kansas and Oklahoma production) to the Midwest.

**Exhibit 6-1 Gas Utility Pipeline And Main**
THOUSAND MILES



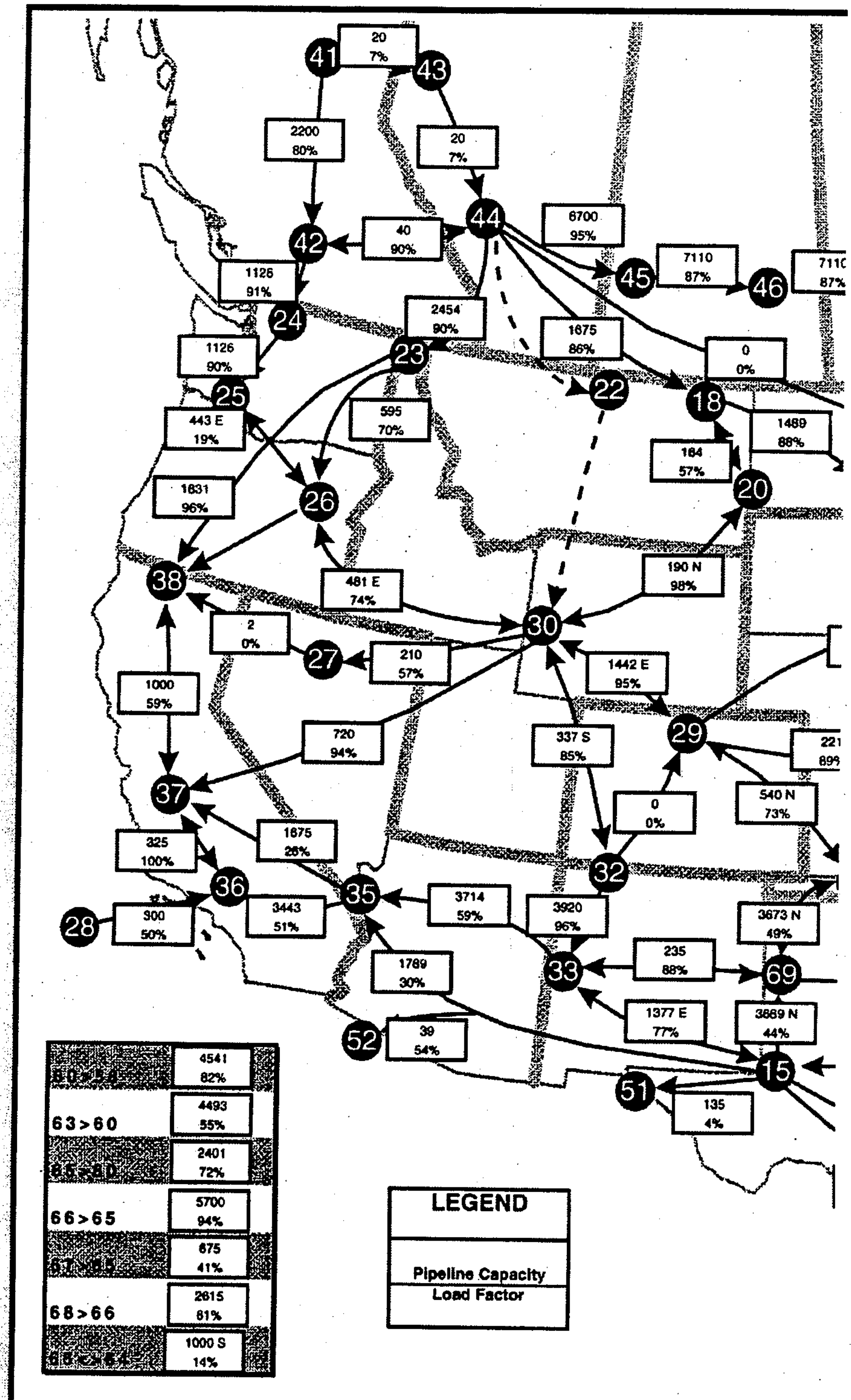

The map on Exhibit 6-2 also shows the estimated average annual load factor for 1997. Weighted by capacity and miles, the major interregional U.S. gas transmission corridors were used at an average 73 percent load factor in 1997. This average is as low as it is because gas pipeline systems traditionally have been designed to supply peak-period gas demand and thus are operated well below capacity for much of the year. Because of the recent growth in U.S. gas demand, the recent trend in pipeline utilization rates has been upward. According to the Energy Information Administration average (unweighted) gas pipeline utilization rates have grown from 68 percent in 1990 to 72 percent in 1997.[3]

## The Economics Of New Gas Pipeline

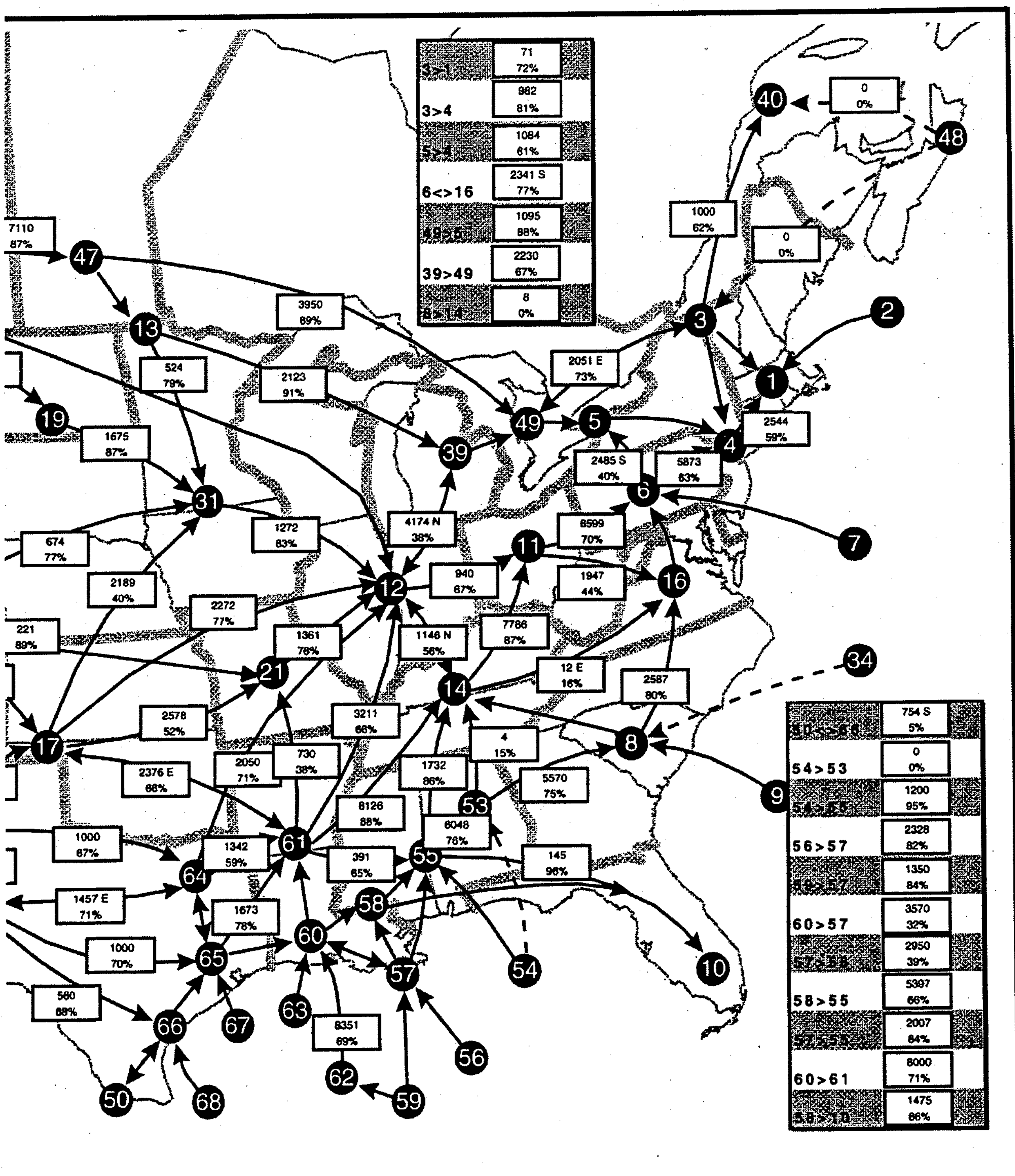
Exhibit 6-3 shows the cost of new gas pipeline as a function of inside pipe diameter. The symbols on the diagram represent the annual average cost for U.S. pipeline projects reported in the *Oil and Gas Journal* for the years 1993 to 1996. The line through the symbols is a regression line that best fits those data and represents an "expected" or average cost for each diameter. For example, 16-inch pipe has an expected cost of $550,000 per mile, while 36-inch pipe would be expected to cost $1.3 million per mile.

For any given period there will be a wide range of costs reported for various pipeline projects of a similar pipe diameter. For example, the typical range in costs for 36-inch pipeline has been about $700,000 to $2.5 million per mile. The range in

**Exhibit 6-2 Capacity Of Major Gas Pipeline Corridors – 1997**

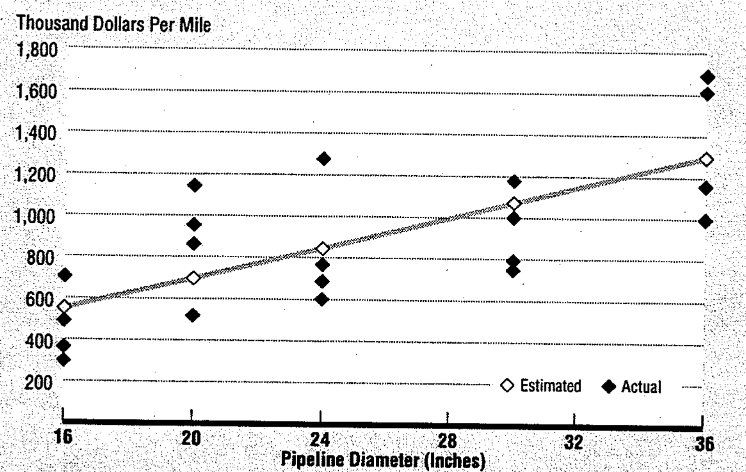



3. EIA, Natural Gas 1998: Issues and Trends.



71
72%
3>4
982
81%
1084
61%
6<>16
2341 S
77%
1095
88%
39>49
2230
67%
8
0%
0
0%
1000
62%
0
0%
7110
87%
3950
89%
2051 E
73%
524
79%
2123
91%
2544
59%
1675
87%
2485 S
40%
5873
63%
674
77%
1272
83%
4174 N
38%
8599
70%
940
87%
1947
44%
2189
40%
2272
77%
221
89%
1361
78%
1146 N
56%
7786
87%
12 E
16%
2587
80%
754 S
5%
2578
52%
3211
66%
4
15%
54>53
0
0%
2376 E
66%
2050
71%
730
38%
1732
86%
5570
75%
1200
95%
8126
88%
6048
78%
56>57
2328
82%
1000
67%
1342
59%
391
65%
145
96%
1350
84%
1457 E
71%
1673
78%
60>57
3570
32%
1000
70%
2950
39%
560
68%
58>55
5397
66%
8351
69%
2007
84%
60>61
8000
71%
1475
86%

**Exhibit 6-3 Gas Pipeline Costs**




Source: Oil and Gas Journal, EEA.

costs can be explained to a large degree by where the pipelines are built. A pipeline path through mountainous terrain or across many rivers adds to costs. Capital expenses also may rise when the pipeline goes through developed areas because the cost of rights of way usually increase, regulatory delays can mount due to more public intervention, and the pipe design may have to be upgraded for safety with, for example, additional wall thickness.

**Exhibit 6-4 Breakdown Of Pipeline Construction Costs**

| | Land | Offshore |
|---|---|---|
| Material | 39.0% | 48.2% |
| Labor | 40.5% | 35.3% |
| R.O.W. & Damages | 2.9% | NA |
| Miscellaneous | 17.5% | 16.5% |
| | **100.0%** | **100.0%** |

Source: Oil and Gas Journal.

Exhibit 6-4 shows how the cost of new pipeline is broken down among material, labor, rights of way and damages, and other components (surveying, engineering, supervision, administration and overhead, interest, regulatory filing fees and contingencies). For onshore pipe, materials and labor each contribute about 40 percent with the miscellaneous components adding about 18 percent. For offshore pipelines, materials make up a larger share of total costs: 48 percent versus 35 percent for labor.

The capacity of a gas pipeline to carry gas depends primarily on its operating pressures. A higher operating pressure and a greater pressure drop between compressor stations increase a pipeline's carrying capacity. However, there is an economic tradeoff between higher pressure and the extra pipeline wall thickness needed to safely confine those pressures. Similarly, a pipeline designed for large pressure drops requires higher initial costs for compressors and greater fuel use. For a typical pipeline built in the U.S. these tradeoffs are resolved by designs that yield maximum operating pressures of about 1,000 psig and pressure drops of about 340 psig (that is, gas enters compressor stations at about 760 psig). Such a design means that compressor stations will be spaced about 65 miles apart and that there will be approximately 15 horsepower of compression per million cubic feet of daily capacity (based on a compression ratio of 1.31).

Exhibit 6-5 summarizes the costs and capacities of different size pipeline using the typical design and cost parameters described above. The costs for a typical 36-inch line would be $1.3 million per mile or $1.20 per Mcfd of capacity per mile. In 1996 the cost of gas pipeline compressors installed on land averaged $1,390 per horsepower. At this cost, compression on a 36-inch pipeline will add $350,000 per mile of pipeline or $0.32 per Mcfd of capacity per mile of pipe, bringing the total cost of the pipeline including compressors to $1.52 per Mcfd/mile. The exhibit demonstrates the economies of scale in pipeline construction. A 24-inch gas pipeline would have expected capital costs of about $2.50/Mcfd/ mile while a 48-inch line would have expected capital cost of only $1.10/Mcfd/mile.

**Exhibit 6-5 Typical U.S. Gas Pipeline Costs**

| Pipe Diameter | Pipeline Cost | Capacity | Pipeline Cost | Pipeline & Compression Cost |
|---|---|---|---|---|
| Inches | $mm/ mile | MMcfd | $/Mcfd/ mile | $/Mcfd/ mile |
| 16 | 0.55 | 139 | 3.96 | 4.28 |
| 20 | 0.70 | 245 | 2.85 | 3.17 |
| 24 | 0.85 | 389 | 2.18 | 2.50 |
| 28 | 1.00 | 574 | 1.73 | 2.06 |
| 32 | 1.15 | 805 | 1.42 | 1.75 |
| 36 | 1.30 | 1,084 | 1.20 | 1.52 |
| 42 | 1.53 | 1,601 | 0.95 | 1.28 |
| 48 | 1.76 | 2,245 | 0.78 | 1.10 |

## Expansion Of Existing Pipeline Systems

Sometimes when a pipeline is built, not all of the planned compression is installed. For example, compressor stations could be built every 130 miles instead of every 65 miles. Building only half of the planned compression would reduce the capacity of the pipeline about 30 percent below the values shown in Exhibit 6-5. When the demand for pipeline service grows to the point justifying it, additional compression is added to bring the pipeline up to its initial full-design capacity. This is called a "compression only" expansion.

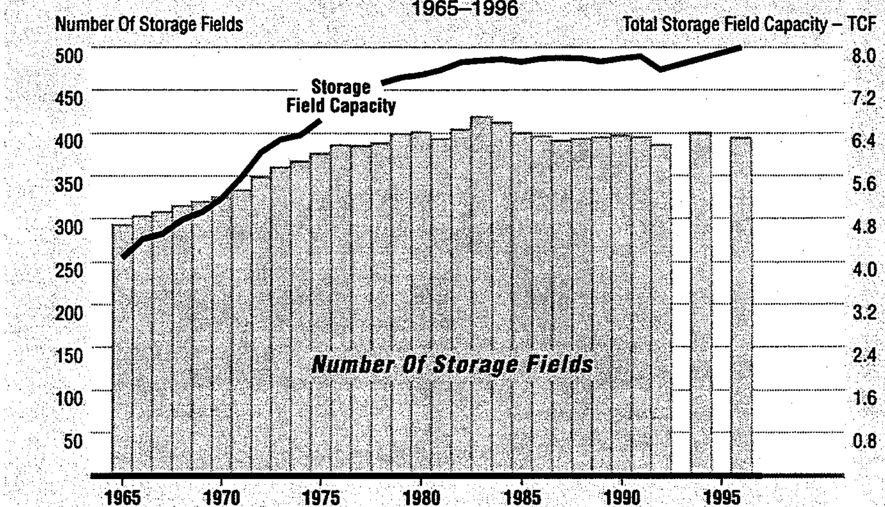
Capacity also can be added to any existing pipeline system by "looping" — adding parallel pipe along part or all of the existing pipeline's length. Expansions also take place by "looping and compression" whereby some parallel pipe and some additional compression are added. Looping and compression expansions can add small or large amounts of new capacity depending on how much pipe and compression are built. Capacity added by looping and compression tends to be less expensive than greenfield pipeline projects because some costs such as surveys and purchase of land and rights-of-way are not incurred.

## Existing Regional Storage Capacity

According to the American Gas Association (AGA), total underground storage field capacity, including base gas, has grown from 4.1 Tcf in 1965 to 8.0 Tcf in 1996. The total number of storage facilities increased from 293 in 1965 to 419 in 1983 before falling off to 394 in 1996. Exhibit 6-6 illustrates the growth in storage capacity over this time period.

Gas storage is used for a variety of purposes by different types of customers. Pipelines and local gas distribution companies use storage to maintain desired gas pressure throughout their pipeline systems, and to optimize the performance of their systems in delivering gas to customers when needed. Also, storage is used as an emergency backup source of gas in event of a production failure, producer non-delivery, or other system failure. Storage capacity in the producing regions can replace additional production ca-

**Exhibit 6-6 Total U.S. Underground Storage Field Capacity**
**1965–1996**




Source: AGA Gas Facts

pacity while market area storage reduces the need for pipeline capacity between gas production and market areas. Seasonal storage requires long-term, large capacity storage that can be drawn on throughout the heating season. Short-term, high deliverability, peaking storage can be used to meet peak demands on a limited number of days with the highest demand during the winter. Peaking storage also can be used during other seasons to make up for supply disruptions or to meet increases in demand for electric generation in the summer.

The potential to develop storage capacity differs by region. As a result, there is significant regional variation in the type and quantities of storage capacity available. Exhibit 6-7 illustrates the regional distribution in storage capacity.

**Exhibit 6-7 Underground Natural Gas Storage**
— Capacity By Region —

| Region | Facilities | Working Gas Capacity | Deliverability | Days Of Capacity |
|---|---|---|---|---|
| | # Of | Bcf | Bcf/d | # Of |
| Northeast | 121 | 670 | 11.7 | 57 |
| Midwest | 33 | 1,131 | 24.0 | 47 |
| Southeast | 128 | 174 | 5.2 | 33 |
| Central | 49 | 566 | 6.0 | 94 |
| Southwest | 67 | 983 | 20.5 | 48 |
| West | 12 | 244 | 7.1 | 34 |
| **Total U.S.** | **410** | **3,767** | **74.6** | **51** |

Source: Energy Information Administration

There are four main types of gas storage facilities: depleted fields, aquifers, salt caverns and Liquefied Natural Gas (LNG). Each of these storage types has distinctive characteristics and can be used to satisfy different storage needs.

Depleted Fields:

Most underground natural gas storage capacity is created from depleted oil and gas fields that have been converted to storage use. Typically, depleted fields have a large working gas capacity relative to deliverability and are used primarily for seasonal storage. However, depleted fields with high deliverability are used for peaking storage.

Aquifers:

In areas that lack suitable depleted fields, natural aquifers have been used for natural gas storage. Aquifer storage often requires greater observation and care when injecting and withdrawing gas than depleted fields. Aquifer storage facilities are heavily concentrated in the Midwest market area in Illinois, Indiana and Iowa.

Salt Caverns:

Salt caverns have very high deliverability relative to storage volumes and can be cycled several times a year. Salt caverns often can be drawn down in as few as 10 days and be refilled in as few as 20 days. This makes salt caverns ideal for meeting peak demand swings and system load balancing, hence salt cavern storage is particularly valuable to electric generators for meeting summer peak cooling demand. Salt caverns are concentrated along the Gulf Coast, although sites have been developed in the Northeast and Mid-continent and potential sites exist in the Western U.S.

LNG:

Liquefied natural gas storage facilities generally are used for peaking purposes in market areas without less expensive alternatives. During times of peak demand, LNG is regasified or vaporized and fed into the pipeline network. Typically, LNG storage facilities only have about five to 10 days of capacity. Liquefaction capacity is very costly and most full-cycle plants (plants with liquefaction, storage and vaporization capacity) only have sufficient liquefaction capacity to fill the storage tanks once a season. Satellite LNG facilities do not have liquefaction capability and have LNG transported to the site by truck or rail. LNG storage is highly concentrated in the Midwest, Northeast and Southeast. More than half of the total U.S. LNG storage capacity is located in just five states: Georgia, Indiana, Massachusetts, New Jersey and North Carolina.

Exhibit 6-8 illustrates the distribution of underground storage capacity and deliverability by type of storage.

**Exhibit 6-8 Natural Gas Storage**
— By Type Of Capacity —

| Type Of Storage Owner | Facilities | Working Gas Capacity | Deliver-ability | Days Of Capacity |
|---|---|---|---|---|
| | # Of | Bcf | Bcf/d | # Of |
| Depleted Field | 343 | 3,299 | 55.2 | 60 |
| Aquifer | 40 | 351 | 8.3 | 42 |
| Salt Cavern | 27 | 116 | 11.1 | 10 |
| **Total U.S.** | **410** | **3,767** | **74.6** | **51** |

Source: Energy Information Administration

## Cost Of New Natural Gas Storage Capacity

Exhibit 6-9 illustrates the average costs of expanding U.S. natural gas storage facilities. The values in this table reflect the average costs from a total of 57 recently completed and proposed new field development and existing field expansion projects.

Storage field development costs vary substantially by the type of storage field. The key issues impacting the development of for each type of storage are summarized below:

### Depleted Fields:

Depleted fields tend to be relatively inexpensive to develop since the existing production wells and gathering lines often can be converted for use in the storage field. Also, the native gas left in the reservoir before conversion can be used as base gas, minimizing the cost of injecting additional base gas. However, field deliverability is limited by the number of withdrawal wells and the geological characteristics of the field. The cost per unit of deliverability can vary widely between projects. The cost of recently

**Exhibit 6-9 Average Cost Of Recently Completed And Proposed U.S. Storage Projects**

| | | Aquifers | | Depleted Fields | | Salt Caverns | | LNG | | All Projects | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Working Gas Capacity | Deliver-ability | Working Gas Capacity | Deliver-ability | Working Gas Capacity | Deliver-ability | Working Gas Capacity | Deliver-ability | Working Gas Capacity | Deliver-ability |
| | | $/MCF | $/MCFD | $/MCF | $/MCFD | $/MCF | $/MCFD | $/MCF | $/MCFD | $/MCF | $/MCFD |
| **Northeast** | New | | | 7.24 | 865.69 | 40.00 | 200.00 | 33.33 | 303.03 | 12.60 | 364.22 |
| | Expansion | | | 6.67 | 165.45 | 12.00 | 60.00 | NA | 59.54 | 8.84 | 102.32 |
| **Midwest** | New | 3.31 | 331.25 | 3.67 | 361.55 | | | | | 3.62 | 357.26 |
| | Expansion | | | 2.32 | 227.45 | | | | | 2.32 | 227.45 |
| **Central** | New | | | | | 5.38 | 118.14 | | | 5.38 | 118.14 |
| | Expansion | | | NA | 116.67 | 6.58 | 79.96 | | | 9.04 | 87.44 |
| **Southeast** | New | | | 2.88 | 284.01 | | | 30.48 | 283.00 | 8.31 | 283.28 |
| | Expansion | | | | | 1.13 | 12.86 | | | 1.13 | 12.86 |
| **Southwest** | New | | | 2.03 | 168.57 | 4.20 | 21.00 | | | 2.07 | 135.78 |
| | Expansion | | | NA | 85.84 | 8.32 | 195.00 | | | 10.76 | 151.37 |
| **West** | New | | | 2.58 | 103.13 | | | | | 2.58 | 103.13 |
| | Expansion | 9.44 | 100.67 | | | | | | | 9.44 | 100.67 |
| **Total U.S.** | New | 3.31 | 331.25 | 3.22 | 218.34 | 10.15 | 134.00 | 31.38 | 289.42 | 4.76 | 212.73 |
| | Expansion | 9.44 | 100.67 | 6.54 | 147.69 | 7.11 | 87.15 | NA | 59.54 | 7.52 | 103.84 |
| | **All** | **5.06** | **149.21** | **3.55** | **200.87** | **8.56** | **108.65** | **34.11** | **221.16** | **5.18** | **172.12** |

Sources: Energy Information Administration and FERC filings.

completed and proposed new depleted fields has averaged $3.22 per Mcf of working gas and $218.34 per Mcfd of deliverability. The cost of depleted field expansion projects has averaged $6.54 per Mcf of working gas and $147.69 per Mcfd of deliverability.

### Aquifers:

Aquifer storage fields tend to be more expensive than depleted fields since all of the injection/withdrawal wells must be newly drilled and new field pipelines must be installed. Also, all of the required base gas must be injected. There are only two new aquifer projects and one expansion project with published costs of construction. The cost of the new aquifer storage projects averages $3.31 per Mcf of working gas capacity and $331.25 per Mcfd of deliverability.

### Salt Caverns:

Salt cavern facilities tend to cost more to construct per unit of total capacity than depleted fields but are cheaper per unit of deliverability. Salt cavern expansions tend to be cheaper than building new capacity, since much of the existing aboveground infrastructure (compressor station, dehydration equipment, etc.) can be shared with the expansion. The cost of recently completed and proposed new salt cavern facilities average $10.15 per Mcf of working gas and $134.00 per Mcfd of deliverability. The cost to expand salt cavern facilities averages $7.11 per Mcf of working gas and $87.15 per Mcfd of deliverability.

### LNG

Liquefied natural gas storage facilities are the most expensive storage medium to build and operate. The cost of constructing recently planned new full-cycle LNG storage facilities averages $34.11 per Mcf of gas storage capacity.

The cost of storage capacity varies by region. Recently completed and proposed storage capacity has been cheaper in the Southeast, Southwest and West, and more expensive in the Midwest. Storage capacity in Northeast is the most expensive. For example, the average cost for new depleted fields in the Southwest has been $2.03 per Mcf of storage capacity and $168.57 per Mcfd of deliverability as compared to $7.24 per Mcf of storage capacity and $865.69 per Mcfd of deliverability in the Northeast. The difference in construction costs is due, in part, to a greater number of suitable depleted fields in the Southwest production region. Also, since storage capacity is more valuable in consuming regions, developers are willing to spend more to develop storage fields in the consuming regions than in the production regions.

# 7. The Market Environment

Gas production and transmission facilities require large capital investments and significant planning and regulatory approval lead times. As a result, individual projects are significantly influenced by a range of regulatory and market factors including:

- Market competition with other fuels,
- Rate and nature of market restructuring, and
- Allocation of market risks.

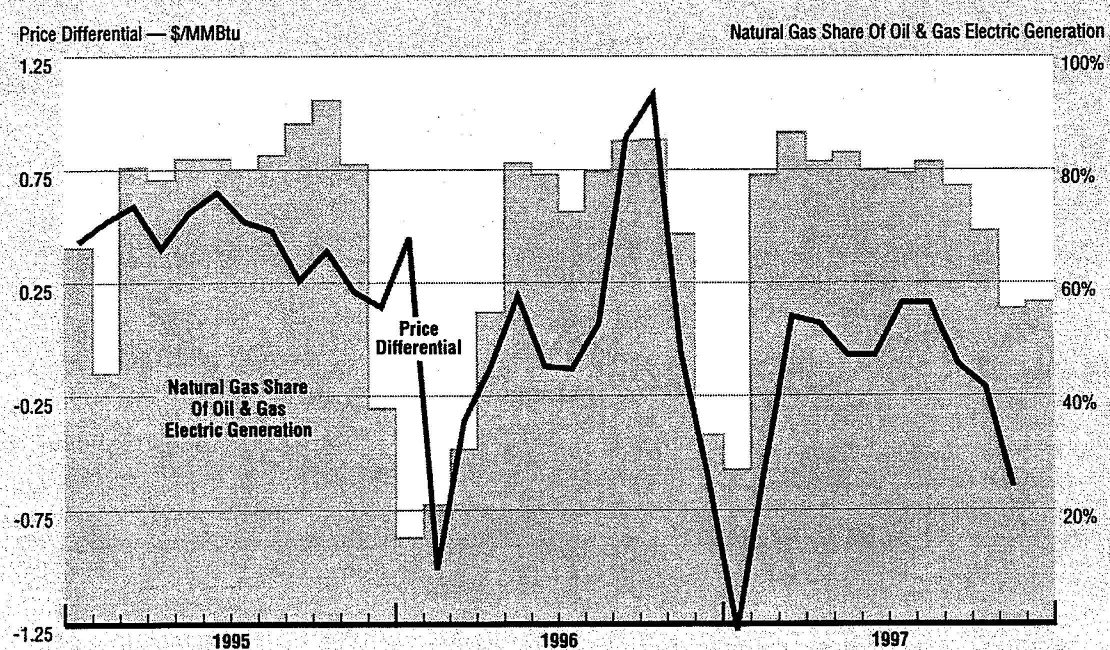
Each of these topics is discussed below.

## Constraints On Gas Prices Due To Competition With Oil And Coal

An important part of the market environment is competition with other fuels, most importantly fuel oil and coal. To the extent gas is priced above residual fuel oil it will lose that portion of the gas load that can use that fuel, chiefly large electric utility steam generators along the Atlantic Coast. Switching to fuel oil is generally a short-term phenomenon that occurs in winter months. Exhibit 7-1 shows how the market shares of gas and fuel oil in utility steam boilers vary in New York as a function of gas and oil prices.

Residual fuel oil sold to large users is typically priced at 80 to 95 percent of RACC on a Btu basis. This means that under the \$16.50/bbl nominal oil price assumed for the year 2000 in the cases examined here, gas would lose market share when it is priced at \$2.30-\$2.70/MMBtu delivered. Distillate fuel oil generally is priced at about 140 percent of RACC to large end-users. Switching to distillate, therefore, would be expected at gas prices starting at \$3.90/MMBtu. Nearly all of the electric utility load

**Exhibit 7-1 Impact Of Gas Price On Gas Consumption By Electric Utilities**
— New York —



that is not switchable to residual fuel oil (including nearly all of the expected new combined cycle gas turbines) could switch to distillate fuel oil. A substantial portion of industrial gas load also can switch to distillate.

In addition to short-term fuel switching to fuel oils, the market for natural gas is constrained by competition with coal in power generation markets. While there is some short-term competition between the dispatch of coal-fired versus gas-fired units when gas prices are low, the greater long run concern is competition in new units. Exhibit 7-2 illustrates how much the low initial costs and high efficiency of gas-fired combined cycle units favor gas over coal in new electric generating units. Even at a very high capacity utilization rate of 80 percent, the delivered price of gas could be as high as $5.14/MMBtu and gas still would be economic. When the project capacity utilization rate falls to 60 percent, the break even price for gas rises to $6.20. This means that as long as gas prices delivered to power generators stay below the $5.14 to $6.20 range, gas will continue to be favored for new generating units.

**Exhibit 7-2 Busbar Cost Example**

Annual Capital Recovery Factor....... 0.15
Capacity Utilization Rate.................. 80%

| | | New Gas-Fired Combined Cycle | New Coal-Fired Unit |
|---|---|---|---|
| Capital............... | $/kW...... | 580 | 1,450 |
| Fixed O&M......... | $/yr....... | 27.75 | 53.52 |
| Variable O&M... | $/kWh..... | 0.0005 | 0.0025 |
| Heat Rate........ | Btu/kWh.... | 7,000 | 9,000 |
| Fuel Price........ | $/MMBtu.... | 5.14 | 1.30 |
| Annual Fixed..... | $/kW...... | 114.75 | 271.02 |
| Annual Fixed.... | $/kWh..... | 0.0164 | 0.0387 |
| Total Variable.... | $/kWh..... | 0.0005 | 0.0025 |
| Fuel.................. | $/kWh..... | 0.0360 | 0.0117 |
| | **Total $/kWh** | **0.0529** | **0.0529** |

## Facilities Planning In A Restructured World

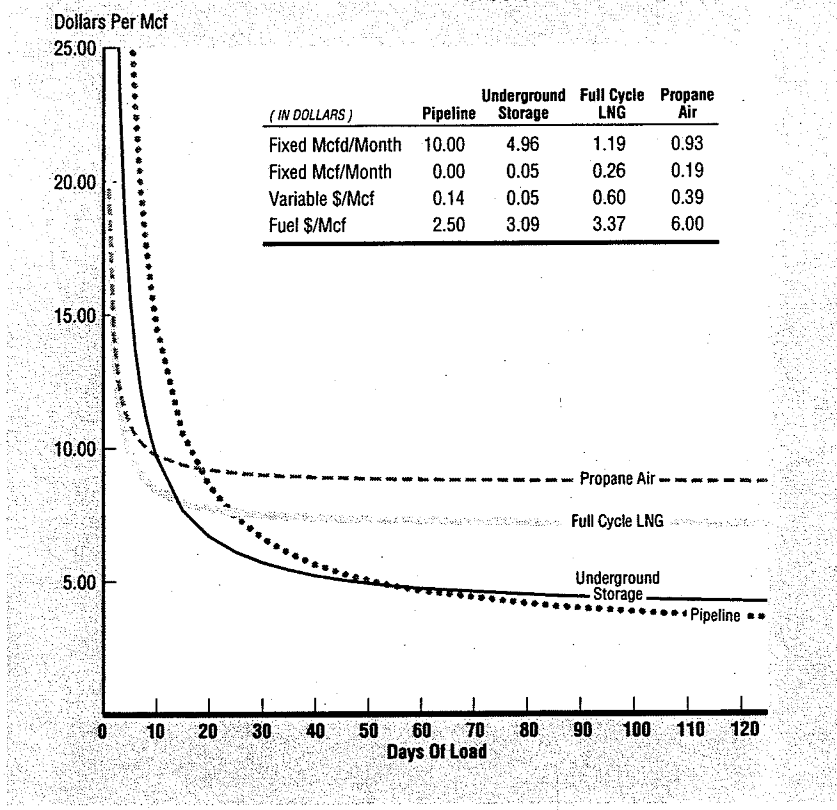
Because gas loads vary greatly by season and day and gas production and transmission facilities require large capital investments, customers rely on a range of options for their gas supply. These options include mainline transmission capacity, underground storage, full cycle LNG plants and gas peakshaving plants. The objective of gas supply planning, traditionally the responsibility of local gas distribution companies, was to match the gas loads within the year to the appropriate gas supply option so as to reduce the overall costs of the gas supply portfolio. This meant building and contracting for facilities to supply all contractually firm customers for "design day" conditions, that is, the coldest day that could be reasonably expected given the region's climatic history.

The specific decisions made by supply planners at the distribution company primarily depended on the types of supply resources available in the service area, costs of each potential resource and the gas demand load profile. In general, the economic decision balanced the fixed and variable costs of each potential supply option against its expected usage during the year. These economic considerations are illustrated in Exhibit 7-3, which shows the cost of various options (pipeline, underground storage, full cycle LNG and propane air) for supplying gas where the duration of the gas load varies from one day to 130 days. The costs include a wellhead cost component of $2.50 per MMBtu where appropriate but ignore the effects of seasonal variations in wellhead gas prices.

Exhibit 7-3 illustrates that a relatively low fixed-cost option with high variable costs, such as propane-air peakshaving, would tend to be economic for only the shortest duration loads while pipeline capacity, characterized by high fixed-costs and low variable costs, would be used for baseload demands. Underground storage, where available, would be selected to meet the intermediate loads lasting at least about 10 days at the higher end down to loads lasting from 90 to 120 days at the lower end. Note that the marginal cost of supplying loads lasting 30 days or fewer ranges from about $5.00 to more than $20.00 per MMBtu.

Although economic considerations were very important in traditional distribution company supply planning, other factors such as the attitudes of the company and local regulators regarding risk, reliability and desirability of designing the system to allow more room for interruptible loads were also important. Furthermore, after gas prices became deregulated and began to show monthly variability, seasonal gas price differences entered into the calculations of what should be the optimal mix of gas supply sources.

**Exhibit 7-3 Illustration Of Supply Alternatives**




| (IN DOLLARS) | Pipeline | Underground Storage | Full Cycle LNG | Propane Air |
|---|---|---|---|---|
| Fixed Mcfd/Month | 10.00 | 4.96 | 1.19 | 0.93 |
| Fixed Mcf/Month | 0.00 | 0.05 | 0.26 | 0.19 |
| Variable $/Mcf | 0.14 | 0.05 | 0.60 | 0.39 |
| Fuel $/Mcf | 2.50 | 3.09 | 3.37 | 6.00 |

Today local distribution companies continue to supply the residential sector and most (71 percent) of the commercial sector under sales service. Only about 17 percent of the industrial sector loads is supplied by local distribution company sales — the remainder being transportation service through a local distribution company (41 percent) or direct deliveries from intrastate and interstate pipelines (42 percent). As more states restructure their gas markets and local distribution companies unbundle their services, the fraction of each sector's gas consumption that will be supplied by local distribution company sales will fall and the portion made up by other shippers, such as gas marketers, will increase. These gas marketers will take on many of the local distribution company's traditional supply planning responsibilities as they contract for wellhead supplies, pipeline capacity, storage and peakshaving services.

Although the regulatory structure under which unbundling will take place is uncertain and will vary substantially from state to state, market prices are expected to become increasingly important in determining what new facilities are built and how they will be operated. The implied costs shown in Exhibit 7-3 for short-duration (that is, coldest weather) demand will be increasingly reflected in monthly and daily gas market prices and facility investors will use those prices to determine when new facilities are needed. Likewise, end-users (or marketers acting on their behalf) will look at market price signals to determine how to contract for alternative gas supply services.

## Who Will Bear The Risk Of New Construction?

Many gas industry observers have expressed concern that needed facilities may not be built because the interested parties will not be willing to agree on an appropriate allocation of risk or because the regulatory structure does not allow agreements into which the parties would like to enter. Some of the sources for these concerns are listed below:

- The most common source of concern is the demise of the regulated markets that allowed the franchise holders (local distribution companies) that signed long-term gas commodity and transportation contracts to be confident that they would have a resale market and would recover their costs. This environment also made it easier for the local distribution companies to build for anticipated storage and peakshaving needs.

- Regulatory oversight often tends to penalize gas procurement practices by local gas distribution companies or regulated electric utilities that result in purchased gas prices above the spot market, but gives little reward for purchase prices below spot indexes. This tends to push parties away from long-term contracts and toward spot market purchases.

- The traditional form of ratemaking calls for a uniform annual rate with a fixed cost component and a commodity cost component, while the restructured markets exhibit values that vary substantially by month, day or even hour. This can lead to mismatches between what the market is willing to pay and what can be charged. The most notable examples of this problem are rate caps that prevent pipelines and shippers who sell capacity in the secondary market from charging rates in peak periods that are high enough to offset steep discounts during the off-peak periods. Capacity can be allocated inefficiently because neither buyer or seller can see the real value of capacity.

- The largest growth sector for natural gas will be in power generation, which is going through a major restructuring and whose future economics of fuel supplies and generating assets are uncertain. Because new power generators will be competing fiercely against each other and will be concerned about their fuel price, and they may be reluctant to enter into long-term wellhead and transportation service contracts that call for any substantial guaranteed payments.

- In today's market, pipeline shippers attach little value to holding contracts with a duration of more than three or five years. In the face of changing market conditions, shippers view a long-term obligation to pay demand charges as unnecessarily risky in the light of the shippers' "right of first refusal" that accompanies all contracts of one year or longer. As a result, there is a mismatch of risk between a pipeline's desire for long-term contract commitments to minimize investment risk and the desire of shippers to limit exposure.

Many of these concerns are the natural result of substituting market forces for regulation. The greater efficiency and faster innovation provided by market forces should make all parties willing to work out solutions to these concerns, although the allocation of risk will fall on the various parties differently than in the past.

# 8. Infrastructure Results For the Four Cases

## Pipeline Construction

Exhibit 8-1 shows historical and projected annual U.S. capital expenditures for natural gas transmission. The historical data were obtained from the *A.G.A. Gas Facts* and are presented in nominal dollars. In the 1970s annual expenditures were usually under $1.0 billion. This increased to more than $1.0 billion during the 1980s and exceeded $2.0 billion in the first part of the 1990s. This increase in expenditures from the mid-1980s to the mid-1990s tracked the rebound in natural gas consumption. Many of these expenditures were for projects (Great Lakes Expansion, Iroquois, Niagara, and the PGT expansion) to increase U.S. access to Canadian gas.

The total capital expenditures for U.S. gas transmission from 1998 to 2010 are projected to be between $30 and $32 billion in the four cases examined in this study. The projected annual average is $2.3 to $2.5 billion, which is somewhat higher than the historical average capital expenditures of $2.3 billion dollars per year over the last 15 years. The projected expenditures are based on either proposed pipeline projects

**Exhibit 8-1 U.S. Gas Transmission Expenditures**

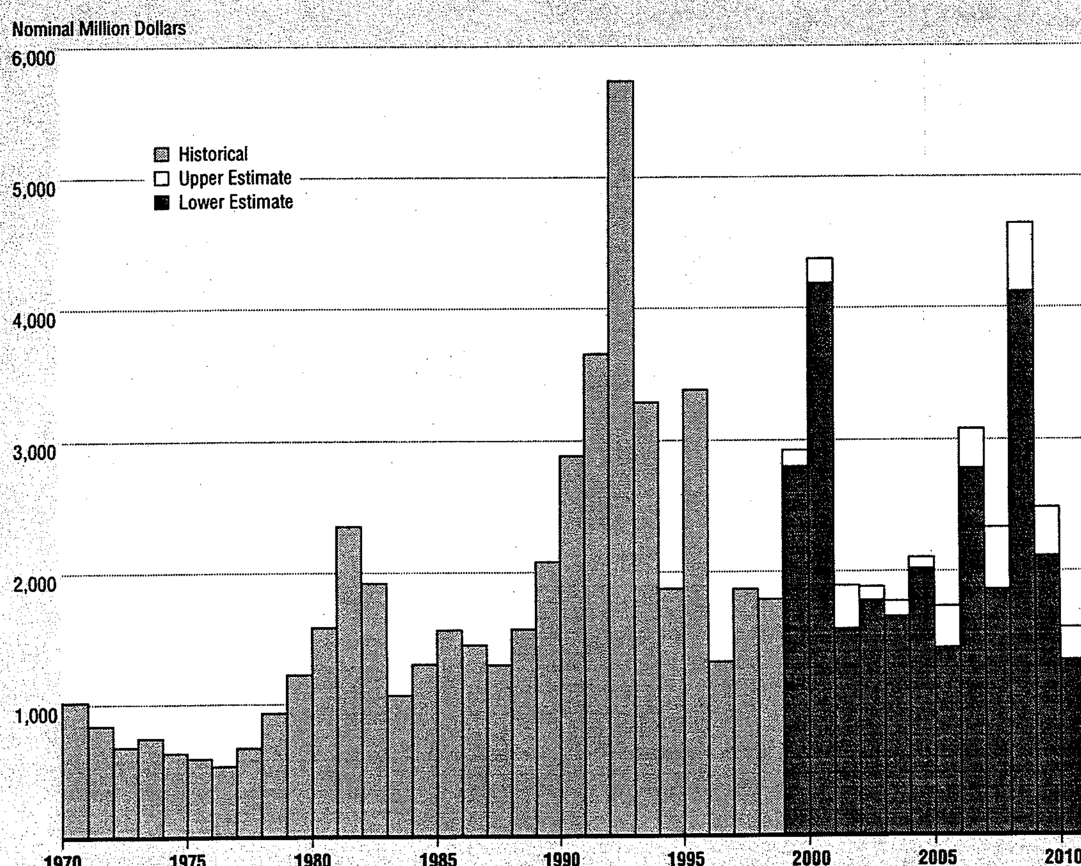


**Exhibit 8-2 Total U.S. Gas Pipeline Investment**
— By Region (1998-2010) —
BILLION DOLLARS

| | Case #1 High Growth | Case #2 Power Gen. | Case #3 High Growth | Case #4 Power Gen. |
|---|---|---|---|---|
| | GULF COAST | | ROCKIES | |
| Mid-Continent & Southwest | 11.8 | 12.3 | 12.0 | 11.8 |
| East & Midwest | 14.7 | 15.0 | 14.7 | 15.0 |
| West | 3.4 | 3.5 | 5.0 | 5.0 |
| **Total** | **29.9** | **30.8** | **31.7** | **31.9** |

**Exhibit 8-3 Total U.S. Gas Pipeline Investment By Type**
1998-2010 ( $BILLION )

| | Case #1 High Growth | Case #2 Power Gen. | Case #3 High Growth | Case #4 Power Gen. |
|---|---|---|---|---|
| | GULF COAST | | ROCKIES | |
| Inter-Regional | 14.7 | 15.0 | 16.5 | 16.0 |
| Area Links | | | | |
| Production | 2.7 | 2.7 | 2.8 | 2.8 |
| Demand | 4.1 | 4.7 | 4.1 | 4.7 |
| Replacement | 8.4 | 8.4 | 8.4 | 8.4 |
| **Total** | **29.9** | **30.8** | **31.7** | **31.9** |

**Exhibit 8-4 Miles Of New Gas Pipeline**

| | Case #1 High Growth | Case #2 Power Gen. | Case #3 High Growth | Case #4 Power Gen. |
|---|---|---|---|---|
| | GULF COAST | | ROCKIES | |
| 1998 | 1,848 | 1,848 | 1,848 | 1,848 |
| 1999 | 2,252 | 2,298 | 2,252 | 2,232 |
| 2000 | 4,988 | 5,034 | 4,988 | 3,126 |
| 2001 | 1,540 | 1,585 | 1,540 | 1,643 |
| 2002 | 1,648 | 1,693 | 1,648 | 1,499 |
| 2003 | 1,662 | 1,708 | 1,662 | 1,558 |
| 2004 | 1,858 | 1,904 | 1,858 | 1,570 |
| 2005 | 1,451 | 1,681 | 1,451 | 1,739 |
| 2006 | 1,592 | 1,687 | 1,592 | 2,537 |
| 2007 | 1,493 | 1,579 | 1,493 | 1,792 |
| 2008 | 2,881 | 2,952 | 2,881 | 3,483 |
| 2009 | 1,631 | 1,899 | 1,631 | 2,006 |
| 2010 | 1,359 | 1,541 | 1,359 | 2,064 |

or hypothetical projects whose cost and other characteristics are based on the "typical" factors described in Section 6. After accounting for projects now under way, it is assumed that additional projects are built only when they are justified economically.

Exhibit 8-2 presents the breakdown of construction expenditures over the entire forecast period among three large U.S. regions. The area with the greatest expenditures is expected to be the East and Midwest, where projects to transport Canadian gas will spur most of the activity. The Mid-continent and the Southwest also will experience substantial activity to supply new gas demand in Florida and other states in that region. Pipeline construction in the West will be comparatively modest as little new capacity into California is projected. The capacity added in the West will be used primarily to supply incremental demands in the Pacific Northwest and to move Rockies gas east. As would be expected, pipeline expenditures are greater in the West for those cases (#3 and #4) with higher Rockies production. It should be remembered that the capital costs and mileage reported in this study are for the U.S. only. There will also be substantial expenditures for facilities in Canada and Mexico to support international trade and to move incremental gas volumes within those countries.

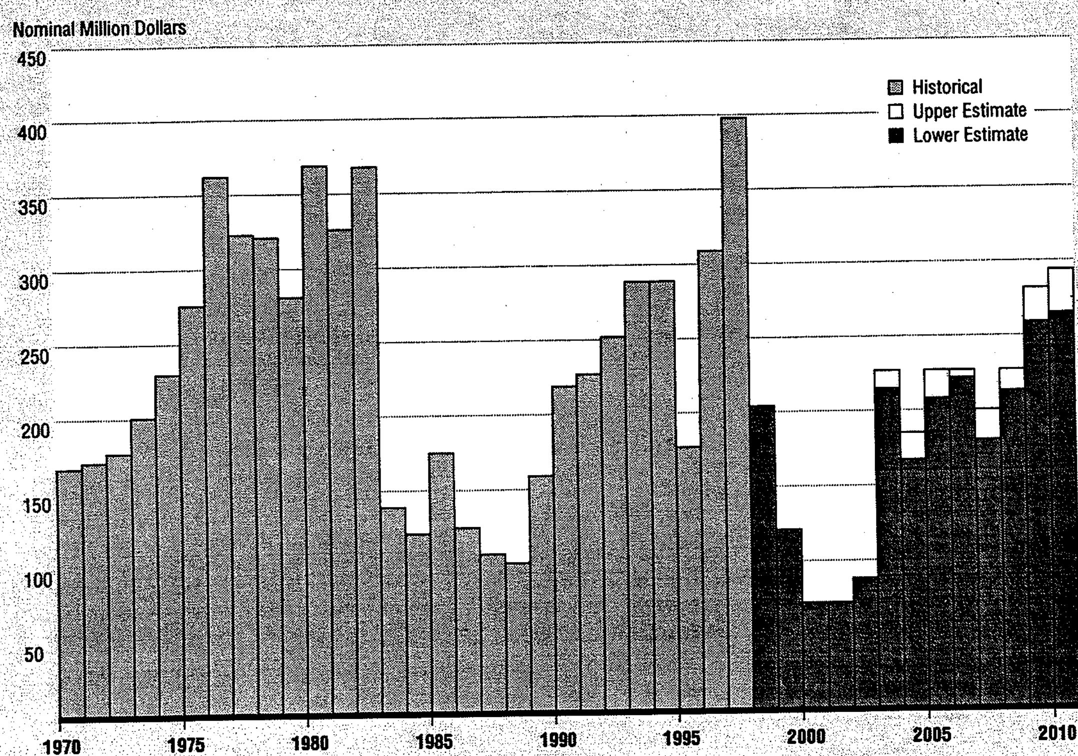
Exhibit 8-3 shows a breakdown of projected transmission expenditures by category. The largest portion of expenditures (about half) is categorized as "inter-regional." This means that the expenditures are for new transmission capacity to move gas between regions. This portion of the expenditures is taken directly from the STM forecast of pipeline capacity requirements. The next two categories, "production area links" and "demand area links," were estimated by EEA based on the production and demand changes in each region. As the labels would imply, "production area links" are projects needed to move gas within supply areas while the "demand area links" are projects to connect up new end users or to supply distribution companies with incremental volumes. Replacement expenditures reflect expenditures to replace existing pipe and compressors. Note that replacement expenditures do not vary among the scenarios. The amount of replacement was assumed to be remain at the levels experienced in recent years (about one half of one percent of operated mileage per year).

The miles of pipeline expected to be constructed each year is displayed in Exhibit 8-4. The average annual mileage, including replacement, is 2,000 to 2,100 among all the cases. According to the *AGA Gas Facts*, there were over 3,000 miles of new gas transmission line built in both 1991 and 1992. Therefore, the average mileage requirements projected in this study are well within the recently demonstrated capacity of pipeline manufactures and construction companies. This conclusion was verified through discussions with pipeline manufacturers and suppliers who saw no trouble in meeting the construction scenarios in this study.

## Storage Construction

Exhibit 8-5 displays annual expenditures for gas storage in the U.S. from 1970. The historical data are from *A.G.A. Gas Facts* and are presented in nominal dollars. The required expenditures for new U.S. gas storage capacity from 1998 to 2010 will total \$2.2 to \$2.4 billion or \$180 to \$190 million dollars per year. This is in line with the actual average expenditures of \$200 million per year over the last 15 years. In all of the examined cases, most of the additional storage capacity is needed in the Northeast U.S.

**Exhibit 8-5 U.S. Storage Expenditures**
NOMINAL DOLLARS — IN MILLIONS



# 9. Conclusions And Challenges

## Conclusions

Two factors will determine whether there will be a 30 Tcf natural gas market in the U.S. by 2010: economic growth and the rate of nuclear and coal power plant retirements. The power generation sector will provide the largest portion of that growth, closely followed by the industrial sector. The 30 Tcf U.S. gas market will take place within a North American market of more than 36 Tcf.

Beyond recognition of the potential for the natural gas industry to substantially increase its North American market, this study provides some answers to the issues identified in the introductory section of this report.

### 1 How Much Infrastructure Will be Needed, and What Will it Cost?

An average of approximately 2,000 to 2,100 miles of new gas transmission pipeline will be needed each year. The required capital expenditures for U.S. gas transmission and storage from 1998 to 2010 will be between $32.2 billion and $34.4 billion. A 30 Tcf market will require substantial new pipeline and storage infrastructure, but at levels that are not outside those of recent history. Therefore, pipe and compressor manufacturers and construction contractors will be able to meet the need for new capacity.

### 2 What Will New Gas Customers be Willing to Pay?

The study found that delivered gas prices must stay below the approximate range of $5 to $6 per MMBtu for gas to beat out coal in new power generation plants. In the industrial and power plant sectors, seasonal fuel switching to residual and distillate fuel oils will take place when delivered gas prices are in the range of 80 to 140 percent of crude oil on a Btu basis.

### 3 Will Wellhead Gas Supplies be Forthcoming at Reasonable Prices?

In recent years, producers have been able to use new technologies and improved business practices to reduce the cost of finding, developing and producing gas. All of the forecasts presented here from EIA, GRI and others suggest that those factors will continue into the future and that a market of around 30 Tcf will require only modest increases in real wellhead prices to a range between $2.10 and $2.70 per MMBtu.

Other issues, such as whether the risks of new infrastructure construction will be properly shared, and who will champion natural gas, depend on continuing regulatory and business developments. They can be addressed in this study only in terms of the challenges outlined below.

## Challenges To The Pipeline and Storage Sectors

While a 30 Tcf market is widely anticipated and economically possible, it will not be achieved easily. All segments of the natural gas industry will face challenges in growing the market to the 30 Tcf level. For the gas transmission and storage segments, the greatest challenges are:

### 1 Earning Adequate Returns To Attract Capital:

As the gas industry has been restructured to reduce the effects of regulation and to enhance the influence of market forces, the risks borne by pipeline and other market participants have increased. Assurances of a reasonable opportunity to earn an adequate return to new pipeline investments will be needed to bring forth the $32.2 to $34.4 billion of investments required to maintain and expand the gas transmission and storage infrastructure in the U.S.

### 2 Achieving A Balanced Environmental Permitting Process:

The required new gas pipeline and storage infrastructure will have to be built on existing and new rights of way and facility sites. Such construction on occasion may come into conflict with other land uses or with esthetics and land preservation. It is important that environmental permitting processes balance — without wasteful delays — the need for energy in a growing U.S. economy energy against other public interests.

### 3 Fostering International Infrastructure Integration:

Approximately 18 percent of the 36.2 to 36.4 Tcf North American gas market anticipated by this study in 2010 will cross an international border before being consumed. This means that the integration of business strategies, infrastructure and operations among Canadian, Mexican and U.S. companies will play an increasingly important role in the future.

## Challenges To The Supply Sector

In the four cases presented in this report, the production of natural gas in the United States grows from 19.7 Tcf in 1997 to between 26.2 and 26.3 Tcf in 2010. This is an increase of 2.2 or 2.3 percent per year. This will require an increase in annual gas completions from an average of about 11,600 in 1995 and 1996 to about 18,000 in 2010. This level of activity will lead to an increase in annual nominal-dollar investment in non-associated gas drilling from about $12.8 billion in 1995/96 to about $26 billion by 2010. The upstream portion of the gas industry faces several challenges in reaching these projected activity and production levels:

### 1 Realizing Returns That Will Support Adequate Production:

Just as with the gas pipeline and storage facilities, producers will not invest their money in oil and gas production without an anticipation of an adequate return on their investment. If oil and gas prices are too low or if the costs of doing business are too high, the upstream investments anticipated here will be delayed and the gas markets will grow more slowly.

### 2 Gaining Access To Public Land For Oil And Gas Supply Development:

Oil and gas production requires the use of onshore and offshore land. To the extent that potentially prospective land is not available to producers, the gas production anticipated here — particularly that in the eastern Gulf of Mexico and Rockies areas — may not materialize and gas markets might grow more slowly.

### 3 Achieving Rational Royalty Policies:

Landowners receive bonuses, rents and royalties from producers for the use of the land for drilling and production operations and as compensation for the oil and gas withdrawn. In the case of offshore regions and certain onshore areas, the landowner is the government. The leasing and royalty policies adopted by federal and state governments must properly balance the government's right to just compensation with the economic realities of oil and gas business. Required payments that are too high or unpredictable due to evolving interpretation of the rules will forestall needed investment.

### 4 Advancing E&P Technologies:

Although oil and gas production often is perceived as an old-line, mature industry, its adoption of a wide range of new technologies in recent years has kept the industry at the forefront of technology innovation and dramatically reduced the effects of resource depletion. The 30 Tcf market goal is not achievable by 2010 without continued development and adoption of new technologies to improve drilling success rates, reduce factor costs and improve production efficiencies.

## Challenges To Market Growth

Natural gas enjoys many advantages in nearly all energy market segments as a clean-burning, efficient, easily controlled and low-cost fuel. However, for natural gas to achieve its maximum market potential the industry must develop strategies to meet the following challenges in the competition for end use markets:

### 1 Supplying Gas At Favorable Prices:

Gas competes primarily with coal and fuel oil in power generation markets and with those primary fuels and electricity in many residential, commercial and industrial applications. Gas must continue to be priced favorably to end-users if gas consumption is to increase substantially.

### 2 Providing Improving End-Use Technologies:

Innovations in gas burning equipment and appliances must keep pace with customers' requirements for better convenience, efficiency, cleanliness and cost. A mixture of private investment, cooperative research and development, and targeted government spending on gas technologies should allow gas to maintain its competitive edge.

3 Promoting Fuel-Neutral Air Quality Policies:

The old regime for environmental regulations was to set emission limits by type and quantity of fuel input into powerplants and industrial fuel burning equipment. This tended to be economically inefficient and was biased against gas, which is inherently cleaner and, thus often received the most stringent emission limits. Fuel-neutral, output-based emission standards under which all fuels must meet similar limits will bolster the growth of gas demand.

4 Achieving Regulatory Processes That Foster Competition:

Market competition has reduced the cost of supplying gas to consumers and expanded gas markets. Further market growth to 30 Tcf must be based on continued reliance on markets made up of many players who compete to provide innovative and low cost products and services. This will require reforms to regulations that do not adequately incorporate market factors.

## The Price Of Failure

The gas industry and its suppliers face significant challenges to reach the 30 Tcf market, but these challenges should be manageable if the demand growth is steady and anticipated. Regulatory constraints in the transportation and distribution sectors could impede business solutions, unless all sectors of the gas industry work together. Not meeting the challenges could delay or halt the needed pipeline and storage construction and drilling activity. This would constrain gas supplies, raise gas prices and cause the market for natural gas to grow more slowly. Prospective users of gas will turn to other fuels. Because gas burning equipment typically lasts several decades, this means that potential sales will be lost for years to come.

# Appendix A: Gas Supplies From The Canadian Atlantic

## Introduction

The expansion of the North American gas markets to more than 36 Tcf will require that new sources of supply be found, developed and attached to the existing transmission infrastructure. To illustrate that the gas resource base is dynamic, this appendix focuses on supplies from a new area. This new source is the offshore Atlantic area of Canada. Exhibit A-1 is a regional map of Atlantic Canada showing the location of the Scotian Shelf, Newfoundland Offshore, and Labrador Offshore areas.

**Exhibit A-1 Regional Map Of Atlantic Canada**

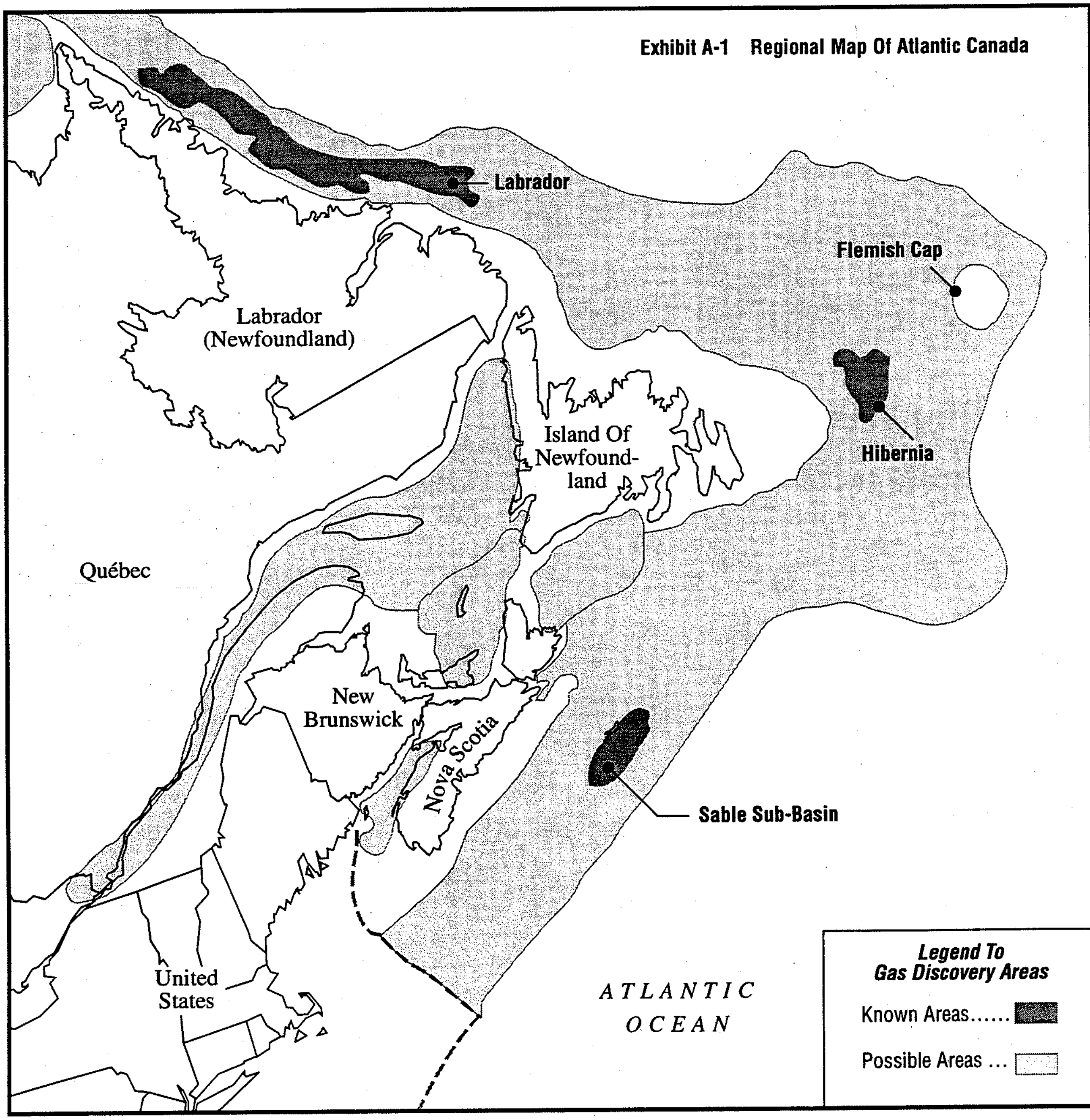


**Exhibit A-2: Summary Of Oil And Gas Discoveries In Offshore Atlantic Canada**

| | DISCOVERED FIELDS | | | DISCOVERED VOLUMES | | |
|---|---|---|---|---|---|---|
| | Oil | Gas | Total | Oil | Gas | NGL |
| | | | | MMB | Bcf | MMB |
| Nova Scotia Offshore | 5 | 19 | 24 | 94* | 5,754 | 93* |
| Newfoundland/ Grand Banks | 15 | 2 | 17 | 1,592 | 4,019 | 237 |
| Labrador Shelf | 0 | 5 | 5 | 0 | 4,224 | 123 |
| **Total** | **20** | **26** | **46** | **1,686** | **13,997** | **453** |

* Estimated from total liquids data and oil vs. gas field information

DISCOVERED FIELDS

## Offshore Nova Scotia

Discoveries found in Offshore Nova Scotia are primarily gas and NGLs. Initial development is under way and will include six gas fields discovered between 1972 and 1985. This development is called the Sable Offshore Energy Project (SOEP).

As shown in Exhibit A-2, there have been 24 discoveries: five oil fields and 19 gas fields. Total volumes discovered are 5,754 bcf of gas and 188 MMBbls of liquids. Gas reserves consist of 5,530 bcf of non-associated gas and 224 bcf of associated gas. The six SOEP fields contain 3,929 bcf of non-associated gas and 73 MMBbls of NGLs. The largest field is Venture, with 1,521 bcf of reserves.

The SOEP project is under construction and initial gas production is scheduled for November 1999 from three fields. The anticipated sales gas rate is 400 MMcfd. Gas will be transported to markets in the northeastern U.S. and eastern Canada through the new Maritimes and Northeast Pipeline. Exhibit A-3 is a map showing the proposed route of the Maritimes and Northeast Pipeline. After the initial planned production rate is established, the other three fields will be developed as needed to maintain production for a project life of 20 to 25 years. Project cost for SOEP is approximately $2 billion, in addition to the $1 billion for the Maritimes and Northeast Pipeline.

UNDISCOVERED RESOURCES

## Offshore Nova Scotia

Exhibit A-4 summarizes published information on the discovered and undiscovered oil and gas resources of Offshore Nova Scotia. The most recent estimate of undiscovered potential was published by the National Energy Board (NEB) in 1998. The NEB estimates that 654 MMBbls of oil and 12,700 bcf of gas remains to be discovered on the Scotian Shelf. This assessment appears to have been based largely upon earlier assessments published by the Geological Survey of Canada (GSC).

The 1997 Canadian Gas Potential Committee report indicates the potential for 8,139 bcf of gas in the Sable Sub-Basin, which is the portion of the Scotian Shelf containing the Sable Island gas fields. The CGPC did not publish an assessment of the other areas of the shelf.

The 1983 GSC assessment indicated a new field gas potential of 23,227 bcf for both the Scotian Shelf and adjoining Georges Bank, which lies to the southwest.

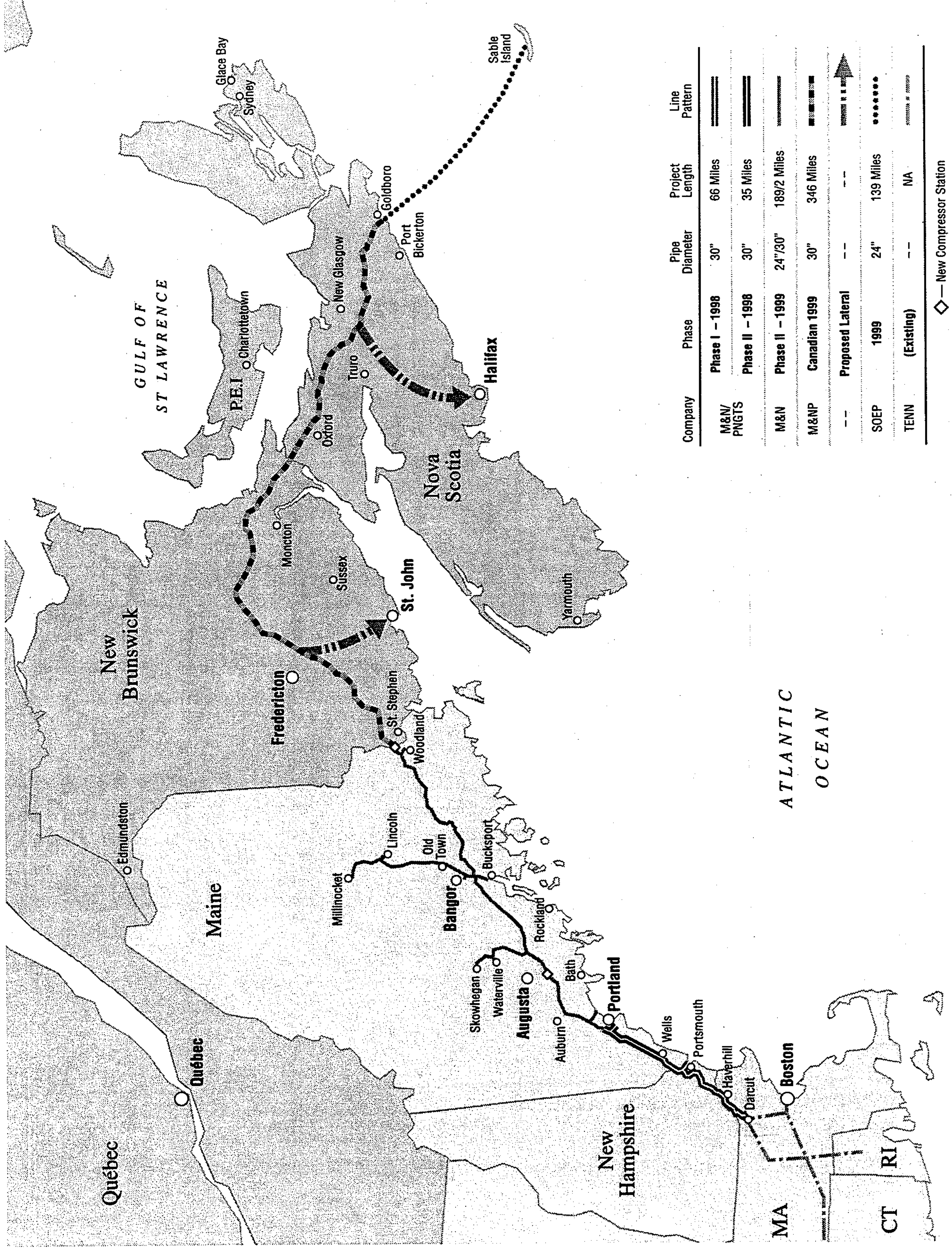
DISCOVERED FIELDS

## Offshore Newfoundland

Discoveries in the Offshore Newfoundland (Grand Banks) area have primarily been oil and associated gas. There have been 15 oil discoveries and two gas discoveries. Total volumes discovered are 1,592 MMBbls of oil, 4,019 bcf of gas, and 237 MMBbls of NGLs. Recoverable gas consists of 500 bcf of non-associated gas and 3,519 bcf of associated gas.

Hibernia Field is the only field whose oil and gas are classified as proven reserves. Oil production from this field began in November, 1997. The field was discovered in 1979 and has reserves of 666 million barrels of oil and 1,017 bcf of gas. Field production capacity is 135,000 BOPD. At year-end 1997,

## Exhibit A-3 Proposed Route Of Maritimes And Northeast Pipeline




| Company | Phase | Pipe Diameter | Project Length | Line Pattern |
|---|---|---|---|---|
| M&N/PNGTS | **Phase I – 1998** | 30" | 66 Miles | |
| | **Phase II – 1998** | 30" | 35 Miles | |
| M&N | **Phase II – 1999** | 24"/30" | 189/2 Miles | |
| M&NP | **Canadian 1999** | 30" | 346 Miles | |
| -- | **Proposed Lateral** | -- | -- | |
| SOEP | **1999** | 24" | 139 Miles | |
| TENN | **(Existing)** | -- | NA | |

◇ — New Compressor Station

**Exhibit A-4: Estimates Of Discovered And Undiscovered Oil And Gas**
— Nova Scotia Offshore —

| | | | Crude MMB | | | | | Gas MMB | | | | | NGL MMB | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Report | As Of | Area | Cumul. Prod. | Estab. Reserves | Other Discov. | Total Discov. | Undis-covered | Cumul. Prod. | Estab. Reserves | Other Discov. | Total Discov. | Undis-covered | Cumul. Prod. | Estab. Reserves | Other Discov. | Total Discov. | Undis-covered |
| 98 NEB | 1-1-97 | Scot. Shlf. | 31 | 13 | 19 | 63 | 654 | 0 | 0 | 5,400 | 5,400 | 12,700 | — | — | — | — | — |
| 98 NSOPB *(discovered only)* | | Scot. Shlf. | — | — | — | 188* | N/A | — | — | — | 5,755 | N/A | — | — | — | — | — |
| 97 CGPG | 1-1-94 | Sable only | N/A | N/A | N/A | N/A | N/A | — | — | — | 4,721 | 8,139 | — | — | — | — | — |
| 94 NEB | 1-1-93 | Scot. Shlf. | 6 | 31 | 19 | 56 | 654 | 0 | 0 | 5,400 | 5,400 | 12,800 | — | — | — | — | — |
| 89 GSC | | Scot. Shlf. | — | — | — | 10 | 699 | — | — | — | 4,110 | 13,930 | — | — | — | 81 | 286 |
| 83 GSC | | Scot. Shlf. | — | — | — | — | 453 | — | — | — | — | 17,932 | — | — | — | — | — |
| | | Geo. Bank | — | — | — | — | 1,057 | — | — | — | — | 5,295 | — | — | — | — | — |
| | | Total | — | — | — | — | 1,510 | — | — | — | — | 23,227 | — | — | — | — | — |

Abbreviations: NEB: National Energy Board • NSOPB: Nova Scotia Offshore Petroleum Board • CGPC: Canadian Gas Potential Committee • GSC: Geological Survey of Canada

Notes: The Georges Bank area is not included in any of the above assessments except the 83 GSC; The NEB includes it with "other frontier basins" and does not provide an estimate (although they presumably use GSC)

• Includes Condensate.

Hibernia was producing only 16,000 BOPD. Associated gas was being flared pending the completion of the gas injection system.

Associated gas from Hibernia is slated for re-injection and there are no announced plans to market it in the near future. However, once the gas no longer is needed for pressure maintenance, a pipeline may be built to bring it to market. Two other oil fields likely will be developed in the near future: Terra Nova and Whiterose. As with Hibernia, there are no plans to bring the associated gas to market. Combined oil production from the three fields is expected to be 350,000 to 400,000 BOPD by the year 2005.

DISCOVERED FIELDS

## Labrador Shelf

In the Labrador Shelf area, which is about 1,000 kilometers north of the Grand Banks, there have been five gas field discoveries. Discovered volumes are 4,224 bcf of gas and 123 MMBbls of NGLs. All of the gas is non-associated. There are no known plans to develop these fields, although the large quantity of gas discovered may eventually make the area economic.

UNDISCOVERED RESOURCES

## Offshore Newfoundland And The Labrador Shelf

Exhibit A-5 summarizes published information on the discovered and undiscovered oil and gas resources of Offshore Newfoundland and the Labrador Shelf. The most recent estimate of undiscovered potential was published by the NEB in 1998. The NEB estimates that 5,328 MMBbls of oil and 53,850 bcf of gas remain to be discovered. (These figures include an allocation of part of the NEB "other frontier basins" category, based upon the 1983 GSC assessment). The NEB assessment is largely based upon earlier assessments by the GSC.

The Newfoundland Offshore Industries Association (NOIA) recently published their basin level assess-

## Exhibit A-5: Estimates Of Discovered And Undiscovered Oil And Gas

— Offshore Newfoundland And The Labrador Shelf —

| | | | Crude MMB | | | | | Gas MMB | | | | | NGL MMB | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Report | As Of | Area | Cumul. Prod. | Estab. Reserves | Other Discov. | Total Discov. | Undis-covered | Cumul. Prod. | Estab. Reserves | Other Discov. | Total Discov. | Undis-covered | Cumul. Prod. | Estab. Reserves | Other Discov. | Total Discov. | Undis-covered |
| 98 NEB | 1-1-97 | Jd'Arc+Lab | 0 | 667 | 912 | 1,579 | 3,189 | 0 | 0 | 8,600 | 8,600 | 36,200 | — | — | — | — | — |
| | | Other* | — | — | — | — | 2,139 | — | — | — | — | 17,650 | — | — | — | — | — |
| | | Total | — | — | — | — | 5,328 | — | — | — | — | 53,850 | — | — | — | — | — |
| 98 NOPB (discovered only) | | Newfound. OS | 0 | 666 | 926 | 1,592 | N/A | 0 | 1,017 | 3,002 | 4,019 | N/A | 0 | 111 | 126 | 237 | N/A |
| | | Labrador Shelf | 0 | 0 | 0 | 0 | N/A | 0 | 0 | 4,224 | 4,224 | N/A | 0 | 0 | 123 | 123 | N/A |
| | | Total | 0 | 666 | 926 | 1,592 | N/A | 0 | 1,017 | 7,226 | 8,243 | N/A | 0 | 111 | 249 | 360 | N/A |
| 98 NOIA | | Newfound. OS | 0 | 666 | 910 | 1,576 | N/A | 0 | 1,017 | 3,002 | 4,019 | 47,700 | — | — | — | — | — |
| | | Labrador Shelf | 0 | 0 | 0 | 0 | N/A | 0 | 0 | 4,224 | 4,224 | 6,000 | — | — | — | — | — |
| | | Total | 0 | 666 | 910 | 1,576 | N/A | 0 | 1,017 | 7,226 | 8,243 | 53,700 | — | — | — | — | — |
| 97 CGPC | 1-1-94 | Jeanne d'Arc | N/A | N/A | N/A | 1,592 | N/A | — | — | — | 4,019 | N/A | — | — | — | 237 | — |
| | | Labrador Shelf | N/A | N/A | N/A | 0 | N/A | — | — | — | 4,554 | N/A | — | — | — | 141 | — |
| | | Total | N/A | N/A | N/A | N/A | N/A | — | — | — | 8,573 | N/A | — | — | — | 378 | — |
| 94 NEB | 1-1-93 | Jd'Arc+Lab | 0 | 616 | 912 | 1,528 | 3,189 | 0 | 0 | 8,700 | 8,700 | 36,400 | — | — | — | — | — |
| 92 GSC | | Jd'Arc | — | — | — | 1,506 | 2,985 | — | — | — | 3,597 | n/a | — | — | — | 109 | N/A |
| 83 GSC | | S. Grand Banks | | | | | 315 | | | | | 3,177 | | | | | |
| | | E. Newfoundland OS Shelf | | | | | 7,095 | | | | | 10,237 | | | | | |
| | | E. Newfoundland OS Basin | | | | | 1,698 | | | | | 13,061 | | | | | |
| | | Subtotal - Grand Banks | | | | | 9,108 | | | | | 26,475 | | | | | |
| | | Labrador Shelf | | | | | 843 | | | | | 26,298 | | | | | |
| | | Total | | | | | 9,951 | | | | | 52,773 | | | | | |

Abbreviations: NEB: National Energy Board • NOPB: Newfoundland Offshore Petroleum Board • NOIA: Newfoundland Offshore Industries Association • CGPC: Canadian Gas Potential Committee • GSC: Geological Survey of Canada • Lab: Labrador Shelf • Newfound. OS: Newfoundland Offshore • Jd'Arc: Jeanne d'Arc Basin (portion of Newfoundland offshore)

Notes: Established or proven reserves represent Hibernia Field only

* Other includes E Newfoundland Basin, S Grand Banks, and Maritimes Basins

ments of undiscovered gas resources. NOIA estimates a remaining undiscovered potential of 53,700 bcf. Much of this assessment also was based upon the earlier GSC studies, with exception of a 20 Tcf reduction for the Labrador Shelf.