American Gas Foundation

# Natural Gas Outlook To 2020

## The U.S. Natural Gas Market — Outlook and Options for the Future

**February 2005**

**American Gas Foundation**
400 North Capitol St., NW
Washington, DC 20001
202-824-7270
www.gasfoundation.org

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**February 2005**

Prepared for the American Gas Foundation by:

Paul Wilkinson and Chris McGill
American Gas Association

and

Kevin Petak and Bruce Henning
Energy and Environmental Analysis, Inc.

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**American Gas Foundation**

Founded in 1989, the American Gas Foundation is a 501(c)(3) organization that focuses on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas. For more information, please visit the website at www.gasfoundation.org or contact Gary Gardner, Executive Director, at 202.824-7270 or ggardner@gasfoundation.org.

American Gas Association

The American Gas Association represents 192 local energy utility companies that deliver natural gas to more than 53 million homes, businesses and industries throughout the United States. AGA member companies account for roughly 83 percent of all natural gas delivered by the nation's local natural gas distribution companies. AGA is an advocate for local natural gas utility companies and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international gas companies and industry associates.

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Energy and Environmental Analysis (EEA), located in metropolitan Washington, D.C., is a nationally recognized consulting firm offering technical, analytical and management consulting services to a diverse clientele. Founded in 1974 to perform economic, engineering and policy analysis in the energy and environmental fields, EEA has exhibited leadership and innovation in investigating energy and environmental issues.

# FOREWORD

Natural gas is a clean, efficient, safe and reliable source of energy that provides one-fourth of the total energy consumed in the U.S. Further, most natural gas consumed in the United States is derived primarily from North American sources. For these reasons natural gas is highly valued by residential, commercial and industrial customers as well as by electricity generators. Also for these reasons, policy makers have generally promoted the use of natural gas. However, natural gas markets have been strained since late in the year 2000 with both tight supplies and higher and more volatile prices than was the case historically. Questions have arisen with respect to the likely role that natural gas will play in terms of meeting future U.S. energy needs and in terms of the outlook for future supply sources and prices of natural gas. Further, what types of actions and energy policies may result in either an improvement or deterioration in the outlook for natural gas? The purpose of this document is to address these questions.

This report analyzes the outlook for natural gas under three alternative policy scenarios. Under none of these scenarios does the natural gas market return to the conditions that prevailed in most of the 1980s and 1990s – surplus supply and relatively low, stable prices. However, it is clear that a number of critical issues currently face both public policy makers and private industry decision makers that will have significant impacts on the availability and price of natural gas for decades to come. Failure to act swiftly, decisively and positively on issues such as the constructing of liquefied natural gas receiving terminals and an Alaskan gas pipeline, diversifying our electricity generating mix and increasing access to domestic supplies of natural gas would prolong and exacerbate problems affecting natural gas markets and all consumers of natural gas.

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# I. EXECUTIVE SUMMARY

The American Gas Foundation study "Natural Gas Outlook to 2020" (February 2005) analyzes the U.S. natural gas market to the year 2020 under three alternative public policy scenarios: "Expected", "Expanded", and "Existing". These scenarios, outlined below, were used to describe potential market conditions and to emphasize the key policy variables that will have an impact on markets through 2020. They were not constructed in an attempt to present the "best" and "worst" possible cases.

| Expected | Expanded | Existing |
|---|---|---|
| The moratoria on exploration & production in the eastern Gulf of Mexico and off the East and West Coasts continues and drilling in the Intermountain West remains partially restricted. Also assumes that an Alaskan natural gas pipeline is operational by 2014 and that liquefied natural gas (LNG) import capacity will be 18 billion cubic feet per day (Bcfd) by 2020. Natural gas fuels 40% of new electricity generation. | Assumes a lifting of the drilling moratoria in the eastern Gulf of Mexico and off the East Coast, but not the West Coast. Under this scenario, access in the Intermountain West is less restricted but it is not unlimited. Also assumes the Alaskan pipeline will be operational by 2014 and LNG import capability is 23 Bcfd by 2020. New electricity generation capacity fueled by natural gas falls to 20% of the total fuel mix. | This "status quo" public policy scenario has the same exploration & production moratoria assumptions as in the Expected scenario. Also assumes that an Alaskan gas pipeline is NOT operational by 2020 and although the four currently operational LNG terminals are assumed to expand, no new terminals are completed. The LNG import capacity is 5.3 Bcfd by 2020. Natural gas fuels 40% of new electricity generation. |

## SUMMARY OF FINDINGS

The results of the study point to the need for public policy makers and industry decision makers to immediately address critical issues that will have a significant impact on the availability and price of natural gas for decades to come. Under none of these scenarios does the natural gas market return to the conditions that prevailed in most of the 1980s and 1990s – surplus supply and relatively low, stable prices. Therefore, failure to act swiftly, decisively and positively on issues such as constructing liquefied natural gas receiving terminals and an Alaskan gas pipeline, diversifying our electricity generating mix and increasing access to domestic supplies of natural gas would prolong and exacerbate problems affecting natural gas markets and all consumers of natural gas.

### *Natural Gas Prices*

*Expected:* Natural gas prices remain in the $5 to $6 per MMBtu range for most of the study period with a 2020 nominal forecast price of $8.15.

*Expanded:* Prices average $5.50 over the entire study period with a 2020 forecast price of $5.47. ***This price is 33% lower than the Expected scenario and results in a savings of roughly $80 billion dollars for consumers in 2020.***

*Existing*: The supply constraints of this scenario push the 2020 nominal forecast price to $13.76 with an average price of $9.43 over the study period. Average natural gas prices are nearly 70% higher in 2020 under the Existing scenario. ***This represents over $120 billion dollars in additional natural gas costs to the U.S. consumer in 2020 versus the Expected scenario and $200 billion versus the Expanded scenario.***

### *Natural Gas Supply*

*Expected:* Natural gas supply will become more diverse, in contrast to the traditional 85% Lower-48 and 15% Canadian supply mix that we have come to expect. This scenario projects much greater supply diversity in the future, including major contributions in the form of Alaskan natural gas and LNG. Delays or denials of these sources will shift supply to more expensive marginal sources of domestic natural gas.

*Expanded:* Despite the measures incorporated under this scenario to increase access to gas supply in the U.S. and Canada, both Lower-48 production and Canadian imports are lower relative to the Expected scenario. The higher level of LNG imports under this scenario acts to reduce exploration for higher cost traditional sources of gas in a lower price environment.

*Existing:* The lower demand level in this scenario is met primarily by a greater dependence on traditional Lower-48 sources of gas and increased Canadian imports. No Alaskan gas is shipped to the Lower-48 and LNG imports do not reach 2 quads per year.

### *Natural Gas Demand*

*Expected*: In spite of higher prices, annual natural gas consumption is projected to exceed 30 quads by 2020. This growth is attributable primarily to continued rising demand for gas to power electricity generation, while residential and commercial demand increase at a modest rate, just over 1% per year. Electricity generation accounts for two-thirds of the natural gas demand growth over the period.

*Expanded:* Total overall consumption is very similar to the Expected scenario, but industrial consumption is higher in response to lower prices while consumption for electricity generation is lower.

*Existing*: Higher prices in this scenario reduce consumption in total and for each of the consuming sectors. Consumption is somewhat lower in the residential and commercial sectors, but two quads lower for electricity generation and one quad lower for industrial customers.

### *Critical Study Implications*

- The extreme prices of the Existing scenario are the result of not expanding the natural gas infrastructure much beyond that which is in place today. Operating under the Expected or Expanded scenario would require a significant increase in the natural gas infrastructure, including LNG terminals and the Alaskan gas pipeline.

- Increased unemployment, plant closings and the movement of industrial operations overseas have occurred over the past four years, in part in response to higher natural gas prices. The industrial sector will remain the most sensitive sector to tight supplies and high prices.

- Due to expectations of continued access restrictions and declining deliverability, both Lower-48 and Canadian sources will struggle to keep production stable at the current levels.

- Expectations for persistent tight market conditions are not a negative reflection on the natural gas resource base – domestic or worldwide. Ample resources of natural gas exist to meet demand for generations to come. However, the U.S. industry is severely restricted in terms of exploring for, producing and delivering natural gas, and severe restrictions are likely to remain.

- The outlook for significant natural gas-fired demand growth by electricity generators is unlikely to be altered, particularly prior to 2015, due to increasing use of the vast number of gas units completed over the past five years and the difficulty in siting and constructing coal or nuclear generating units in less than 10 years.

- Natural gas demand will become less predictable as the relative share of total demand attributable to electricity generators increases, while the relative share attributable to the industrial sector declines.

- The lack of a contribution in the Existing scenario from new LNG operations and Alaskan gas most likely would occur as a result of environmental opposition to the siting and construction of new facilities. However, failure to construct these new facilities would result in a far greater reliance on Lower-48 sources of supply, increasing the need to drill in both onshore and offshore areas, which also will be subject to environmental concerns.

## II. SCENARIOS AND IMPLICATIONS

This study analyzes U.S. natural gas markets through the year 2020 under three alternative scenarios. The focal point of the study is the "Expected Policies" scenario. This scenario assumes that U.S. energy policy decisions over the next 16 years are relatively consistent with those that are being made today or that have been made in the recent past. The "Expanded Policies" scenario employs a number of modifications to both natural gas supply- and demand-related assumptions that act to ease pressure in the gas market and that, by doing so, ultimately reduce the cost of gas to the consumer. The third scenario is the "Existing Policies" scenario. This scenario was constructed under the assumption that most projects to expand gas supply would be impeded, and that major modifications in terms of gas demand would not be undertaken.

These scenarios were not constructed in an attempt to present the "best" and "worst" possible cases. For example, it is possible that drilling restrictions in the Intermountain West could be even more severe than they are today, but that possibility was considered remote and it was not incorporated in the Existing Policies scenario. Conversely, it is possible that all offshore areas currently subject to a drilling moratorium could be opened, but the possibility of drilling off the West Coast is considered so remote that it was not included in the Expanded Policies scenario. Changes expected to have only a modest impact over the forecast period, such as changes to appliance efficiency standards, also were not included. (Some potential variables were considered but ruled out after preliminary model runs found their impacts to be minimal or inconclusive.) This study attempts to present plausible scenarios with an emphasis on the key policy variables that will have an impact on natural gas markets through 2020. Each of the scenarios is described below.

**Expected Policies**

Under the Expected Policies scenario it is assumed that domestic drilling opportunities will change little throughout the forecast. The moratoria on exploration and production in the eastern Gulf of Mexico and off the East and West Coasts will continue, and drilling activity in the Intermountain West will remain partially restricted. It is assumed that an Alaskan natural gas pipeline will be operational by 2014, and that liquefied natural gas (LNG) import capacity will be 18 billion cubic feet per day (Bcfd) by 2020. This LNG capability is based on an expansion of the four currently operational receiving terminals to 5.3 Bcfd and the construction of nearly 13 Bcfd of new capacity. In this case, LNG meets 22 percent of total gas demand in 2020. Electricity generating capacity under the Expected Policies scenario expands by roughly 150 gigawatts (GW), including 60 GW of gas-fired capacity, 50 GW of coal-fired capacity, and 40 GW of renewable capacity.

**Expanded Policies**

The Expanded Policies scenario assumes a lifting of the drilling moratoria in the eastern Gulf of Mexico and off the East Coast, but not the West Coast. Access in the Intermountain West is less restricted under this scenario than is currently the case, but it is not unlimited. The Alaskan pipeline assumption is the same as under the Expected Policies scenario – operational by 2014. LNG import capability is 23 Bcfd by 2020, 28 percent greater than under the Expected Policies scenario. LNG under this scenario ultimately provides 28 percent of U.S. gas supply. Natural gas-based electricity generating capacity increases by 30 GW under this scenario, half as much as under the Expected Policies scenario. Coal, nuclear and renewable capacity are each roughly 10 GW greater in this case – the nuclear increment results primarily from a greater utilization of existing plants, although 2.5 GW of new nuclear capability is also added.

**Existing Policies**

Under the Existing Policies scenario no changes were assumed with respect to the in-place offshore moratoria, nor were any changes assumed with respect to access in the Intermountain West. It was assumed that an Alaskan gas pipeline would not be operational by 2020, and although the four currently operational LNG terminals were assumed to expand, no new terminals would be completed. The LNG capacity of 5.3 Bcfd could supply roughly 7 percent of this case's (lower) total demand in 2020. The electricity generating addition assumptions are the same as in the Expected Policies scenario, including 60 GW of new gas-fired capacity.

**Common Assumptions**

A number of key variables were assumed to be the same in all three cases, including:

**Annual GDP growth rate:** 2.8% per year
**Industrial production growth rate:** 2.3% per year after 2003
**Coal prices:** increase at 1% per year
**Oil prices:** RACC declines to $28/bbl by 2010, and increases 2% annually thereafter
**Electricity generating capacity additions:** short-term additions based on existing development plans, long-term assumes 1.9% annual growth rate in electricity output
**Capacity utilization of coal generating units:** 70% today, 73% in 2010, and 78% in 2020
**Nuclear generation:** capacity utilization continues at current level, no major retirements

## A. EXPECTED POLICIES SCENARIO

**In spite of a higher price environment, annual natural gas consumption is projected to exceed 30 quads by 2020.** Total U.S. consumption of natural gas is projected to increase nearly 40 percent by 2020, from 22.1 quads in 2003 to 30.5 quads in 2020. (See Exhibit II-1.) This growth is attributable primarily to continued rising demand for gas to power electricity generation, while residential and commercial demand will increase at a modest rate, just over 1 percent per year. Gas consumption by electricity generators is projected to increase by 6.0 quads by 2020 as compared with growth of 1.1 quads and 0.7 quads for residential and commercial customers, respectively. Industrial gas consumption is expected to rebound, after falling sharply between 2000 and 2003. The increase in industrial consumption from 7.4 quads in 2003 to 7.7 quads in 2020, however, is relatively modest.

Natural gas supply will become more diverse, in contrast to the traditional 85 percent Lower-48 and 15 percent Canadian supply mix that we have come to expect. The projected supply in 2020 is 61 percent Lower-48, 22 percent LNG, 9 percent Alaskan and 8 percent Canadian. Lower-48 gas will remain the primary source of supply, but even with higher prices production will struggle to stay between 18 and 19 quads per year. Canadian production will be similarly affected, and Canadian gas also will be used to satisfy growing Canadian demand, resulting in a decrease in exports to the U.S. from 3.3 quads in 2003 to 2.3 quads in 2020. LNG will be the

# Exhibit II - 1

## Comparison of Long-Term Scenarios
## 2003 – 2020

| | | FORECAST - 2020 | | |
|---|---|---|---|---|
| **CONSUMPTION (TBtu)** | Actual 2003 | Expected Policies | Expanded Policies | Existing Policies |
| Res | 5,188 | 6,326 | 6,417 | 6,076 |
| Com | 3,287 | 3,944 | 4,074 | 3,610 |
| Ind | 7,412 | 7,739 | 8,268 | 6,718 |
| EG [1] | 4,230 | 10,203 | 9,526 | 8,226 |
| Pipe [2] | 777 | 993 | 976 | 930 |
| L&P [3] | 1,247 | 1,254 | 1,211 | 1,336 |
| Total | 22,141 | 30,459 | 30,472 | 26,896 |
| **SUPPLY (TBtu)** | | | | |
| L-48 | 18,655 | 18,966 | 18,325 | 20,671 |
| Alaska [4] | 362 | 2,724 | 2,700 | 406 |
| Canada | 3,300 | 2,326 | 1,266 | 3,944 |
| Mexico | -350 | -177 | -177 | -177 |
| LNG | 478 | 6,835 | 8,569 | 1,931 |
| Total | 22,445 | 30,674 | 30,683 | 26,775 |
| **PRICE ($/MMBtu, Henry Hub)** | | | | |
| Nominal | $ 5.49 | $8.15 | $5.47 | $13.76 |
| Nom. Avg (2004-2020) | | $6.72 | $5.50 | $9.43 |

[1] Electricity generation.
[2] Pipeline compressor fuel.
[3] Lease and plant fuel.
[4] Includes gas consumed in Alaska and the Lower-48, but excludes LNG exports.

relief valve, increasing nearly 15-fold by 2020. LNG is projected to supply 2.9 quads to U.S markets by 2010 and 6.8 quads by 2020.

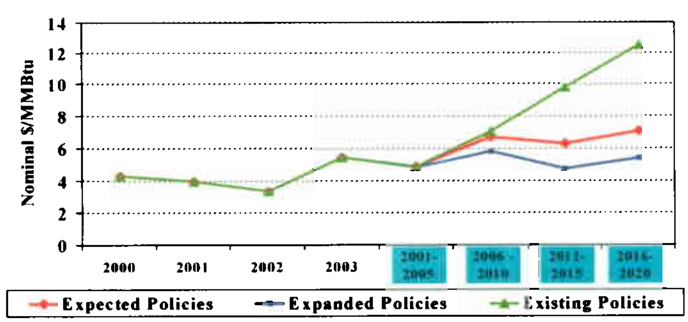
Natural gas prices are expected to remain in the $5 to $6 range for most of the forecast period, falling modestly in the 2010 to 2015 timeframe as new sources of LNG and Alaskan gas enter the market, but rising again between 2015 and 2020 as Lower-48 production is strained. (See Exhibit II-2.) Appreciably lower gas prices over the next several years – or prior to the construction of one or two new LNG terminals – is not considered likely under any of the scenarios examined. Although LNG would be competitive at significantly lower prices, lower prices would render some Lower-48 production uneconomic. It should be noted that, when adjusted for inflation, real natural gas prices actually fall – from $5.49 per MMBtu in 2003 to an average of $4.93 from 2011 through 2020 ($2003 per MMBtu at the Henry Hub).

Some of the key findings of the Expected Policies scenario are highlighted below.

**Electricity generation will account for two-thirds of the natural gas demand growth over the forecast period.** Gas consumption for electricity generation is projected to increase from 4.2 quads in 2003 to 6.8 quads in 2010 and to 10.2 quads in 2020. Sales of electricity are projected to increase by over 38 percent over the forecast period and gas is expected to account for 26 percent of the electricity generated in 2020 versus 15 percent today. Gas is not expected to capture as much of the new generation market in the future – down to 40 percent of the new market as opposed to the more than 90 percent it has realized in recent years. However, much of the generating capacity required in 2020 is already on line or under construction. There are 410 gigawatts of gas-fired capacity on line today with a projected total of 466 gigawatts by 2020.

**Exhibit II-2**

**Actual and Projected Natural Gas Prices (Henry Hub)**




Forecasted prices are in 5 year averages.

Environmental issues and lengthy lead times will limit the contribution of new coal-fired capacity prior to 2015, and the contribution of coal to the overall generation mix is projected to decline modestly, from 55 percent today to 50 percent in 2020. Despite a five-fold increase projected for renewable sources of electricity (solar, wind and biomass) over the forecast period, these sources will account for only 1 percent of the electricity generated in 2020. No new nuclear or hydroelectric capacity is anticipated.

**Industrial natural gas demand will rebound and grow, but growth will be sluggish – at about one-third the rate experienced in the 1990s.** Natural gas consumption by the industrial sector was 7.4 quads in 2003, about 15 percent below the 2000 consumption level. Higher prices over the past three years are in part responsible for this load loss, particularly in feedstock applications (ammonia, methanol and hydrogen). A further decline is projected in the gas feedstock industries, but this decline is expected to be offset by increases in boiler and "other" applications as the economy expands. A growth rate of 0.3 percent annually is projected for the industrial sector in total, with an overall consumption of 7.7 quads in 2020. Higher gas consumption growth rates are forecast for the stone-clay-glass, chemical and food industries – 1.0, 0.6 and 0.4 percent annually, respectively. Declines of 1.0 percent and 0.5 percent annually are projected for the steel and paper industries, in addition to an annual decline rate of 0.6 percent for petroleum refining. Growth is expected to be stronger in those industries that are less susceptible to foreign competition and in industries that benefit significantly from market proximity, such as the food and building products industries.

**Modest growth is projected for the residential and commercial sectors, with continued efficiency improvements partially offsetting new customer hookups.** Residential natural gas consumption is projected to increase from 5.2 quads in 2003 to 6.3 quads in 2020. The trend in declining gas usage per residential customer, attributable primarily to tighter homes and more efficient appliances, is expected to continue but at a rate roughly half that experienced from 1980 through 2001. An annual growth rate in residential consumption of 1.2 percent nationally is projected, but rates near or above 2 percent are projected for parts of the West and Northwest. Conversely, rates near or below 1 percent annually are projected in most of the Northeast, Middle Atlantic and Midwestern states. Competition for market share relative to electricity is expected to be intense, particularly in the warmer South Atlantic states.

The projected growth rate for commercial gas consumption (1.1 percent per year) is almost identical to that projected for the residential sector. Increasing consumption in the commercial sector faces the same obstacle as in the residential market. The average consumption per commercial customer fell by 18 percent from 1979 through 1999, limiting growth in commercial consumption to 20 percent despite a 46 percent increase in the number of commercial customers.

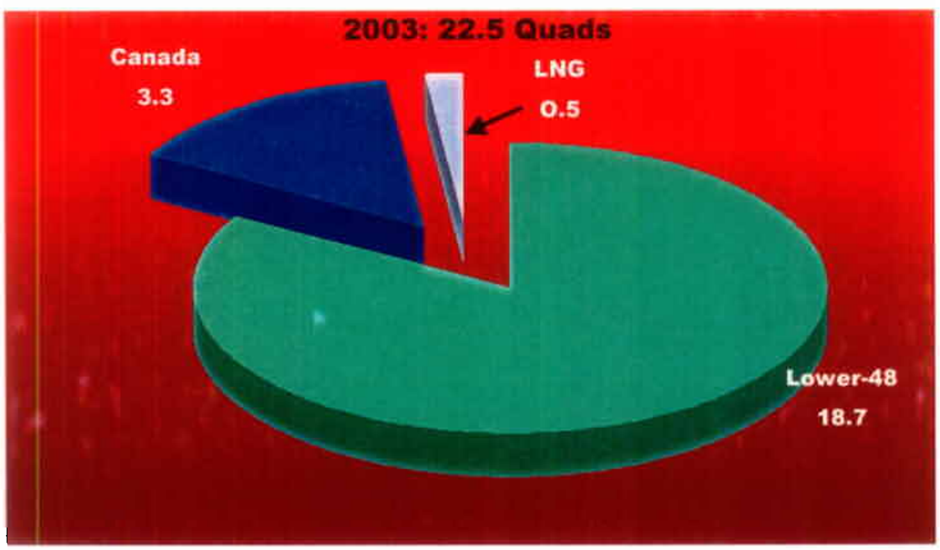
**Lower-48 production will remain the largest component of U.S. gas supply, but producers will struggle to keep production between 18 and 19 quads per year.** Projected Lower-48 production shows little movement in this outlook, staying mostly within a range of 18 to 19 quads per year. The percentage of the total supply mix accounted for by the Lower-48 therefore declines from 83 percent in 2003 to 61 percent in 2020. Although this scenario does not project significant growth in Lower-48 production, it does not forecast a dramatic decline either, as some analysts suggest.

Despite the fact that the U.S. is in the midst of a drilling boom, with 20,000 wells being completed annually, the supply response to this drilling has been modest, at best. In fact, discoveries per well drilled have flattened or decreased in recent years. A dramatic reversal in this trend is not anticipated. Relatively high gas prices have pushed producers toward marginal wells where gas is known to exist. These wells offer low risk and rapid potential depletion, but less volume recovered per well. Additionally, unconventional gas sources, including tight gas sands, coalbed methane and gas shales have become a significant portion of our total supply – almost 30 percent of the total. These sources are attractive in that they tend to produce for 10, 20 or even 30 years. However, unconventional resources usually come from low permeability reservoirs that require a relatively high number of modest production wells.

In this scenario domestic production is expected to remain constrained, both onshore and offshore, by access restrictions. These restrictions, including off the East and West Coasts, in the eastern Gulf of Mexico and the Intermountain West, affect areas believed to have significant production potential. There is no way to precisely quantify the size or quality of gas reserves to be found in restricted areas without exploratory drilling. Thus most analyses, including this one, may actually understate the actual gas resource.

**Exhibit II-3**

**SOURCES OF CURRENT U.S. NATURAL GAS SUPPLY**



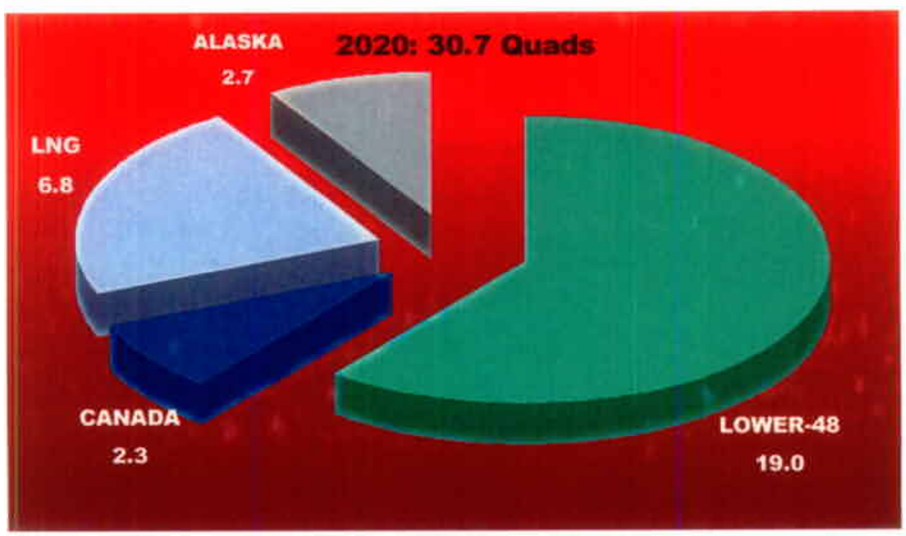

**Canadian imports are expected to fall from 3.3 Quads annually to 2.3 Quads in 2020.** Canadian imports provided 15 percent of total U.S. supply in 2003, but a decline to 8 percent of the total is projected by 2020. This decline is, in part, attributable to increasing gas demand within Canada. Canadian demand projections reflect normal economic and population growth, but they also reflect a significant increase in the use of gas to fuel electricity generation, to combat various forms of pollution and to enhance the production of oil from huge Canadian tar sands deposits.

On the supply side, Canadian producers are facing many of the same problems as U.S. producers. Virtually all Canadian gas production occurs in the Western Canadian Sedimentary Basin, which is reaching maturity. Canadian governmental estimates forecast overall production declines beginning as early as 2005. Efforts have begun to migrate production northward and eastward from traditional producing areas.

A potential offset to pending declines in production from traditional sources is production of coalbed methane (CBM). The Canadian CBM resource is vast, with estimates ranging from 500 Tcf to 2,700 Tcf. However, much of the CBM resource in Canada is unlike that in the U.S. and recovery will be difficult without significant technological advances. It is assumed in this analysis that 95 Tcf of the CBM resource in Canada is technically recoverable.

**Exhibit II-4**

**SOURCES OF PROJECTED U.S. NATURAL GAS SUPPLY**




**LNG imports of 6.8 quads are projected in 2020, accounting for 22 percent of the total U.S. gas supply.** A significant and rapid expansion in U.S. LNG imports is anticipated in this outlook. Imports increase from 0.5 quads in 2003 to 2.9 quads in 2010, to 5.3 quads in 2015 and to 6.8 quads in 2020. Expansions at the existing receiving terminals are assumed, as is the completion of new terminals as early as 2008 when imports account for over 7 percent of the total U.S. supply.

Approximately 93 percent of the world's natural gas resource base is outside of North America, and much of this gas is stranded and seeking a market. The U.S. is one of the most attractive markets for this gas. Additionally, LNG can be economically landed in the U.S. at a price in the \$3.50 to \$4.50 range – today and in the foreseeable future. The Expected Policies scenario assumes that LNG imports will, and in fact must, grow significantly in the very near future.

**Huge quantities of gas at the North Slope are only the tip of the iceberg in terms of Alaska's total natural gas resource, but little progress in developing a transportation system for Alaskan gas has been made over the past 30 years.** The total gas resource potential in Alaska, including the North Slope, Cook Inlet, coal seams and other onshore and offshore areas, is estimated at 251 Tcf. There is no doubt about the size of the Alaskan gas resource, yet this resource will remain stranded until an overland or LNG transportation system is put in place. Little progress has been made on a transportation option over the past three decades, primarily because of the scope of the project. For example, the estimate for the Alaskan natural gas pipeline system is roughly \$20 billion, with a 10-year construction schedule. Volatile natural gas markets and prospects for significant imports of competing LNG cloud the outlook for any Alaskan gas transportation project.

The Expected Policies scenario assumes 4 Bcfd of flowing gas from an Alaskan pipeline by 2014 and an expansion to 6 Bcfd by 2017. Alaska is projected to account for 9 percent of the total U.S. gas supply by 2020. Failure to have a transportation system in place to move Alaskan gas by this date would put further pressure on other sources of supply and prices would be pushed upwards.

### B. EXPANDED POLICIES SCENARIO

**Overall consumption under the Expanded Policies scenario is very similar to the Expected Policies scenario, but average natural gas prices are up to 33 percent lower.** The combination of supply and demand measures taken in the Expanded Policies scenario has a significant impact on gas prices (although the impact is relatively modest prior to 2008-2010). Gas prices in this scenario are 33 percent lower in 2020 than under the Expected Policies scenario - \$5.47 per MMBtu versus \$8.15 per MMBtu. Prices averaged over the entire projection period - \$5.50 per MMBtu - are 18 percent lower in this scenario.

Total consumption of 30.5 quads in 2020 under this scenario is almost identical to the consumption in the Expected Policies scenario, although the breakout by consuming sector shows some key differences. Consumption in the Expanded Policies scenario is only marginally higher in the residential and commercial sectors, but in response to lower prices it is 0.5 quads higher in the industrial sector. Conversely, gas consumption for electricity generation is 0.7 quads lower in the Expanded Policies scenario, the result of an assumed more diverse generating mix.

Despite the measures incorporated under this scenario to increase access to gas supplies in the U.S. and Canada, both Lower-48 production and Canadian imports are lower relative to the Expected Policies scenario. Lower-48 production falls from 19.0 quads in the Expected Policies scenario to 18.3 quads in 2020, while Canadian imports fall from 2.3 quads to 1.3 quads. The higher level of LNG imports under this scenario – 8.6 quads or 28 percent of the supply mix – acts to reduce exploration for higher cost traditional sources of gas in a lower price environment.

## C. EXISTING POLICIES SCENARIO

**Average natural gas prices are nearly 70 percent higher in 2020 under the Existing Policies scenario.** The supply constraints of the Existing Policies scenario push prices to $13.76 in 2020, with an average price of $9.43 over the forecast period. These higher prices, combined with a failure to construct new LNG terminals and the Alaskan pipeline, spur higher production from (higher cost) domestic sources. Lower-48 production reaches 20.7 quads in this scenario, 1.7 quads more than under the Expected Policies scenario. Canadian imports also are higher under this scenario, by 1.6 quads – responding in a similar manner to Lower-48 production.

Not surprisingly, higher prices in the Existing Policies scenario reduce consumption in total, and for each of the consuming sectors. Total consumption falls to 26.9 quads, with declines of 2.0 quads for electricity generators, 1.0 quads for industrial customers and 0.3 quads for both residential and commercial customers, relative to the Expected Policies scenario.

## D. CRITICAL STUDY IMPLICATIONS

- Natural gas price projections are similar under all scenarios until roughly 2008. Some price relief is achievable at that point relative to the Existing Policies scenario due to the availability of LNG, supplemented in 2014 by Alaskan natural gas.

- Due to expectations of continued access restrictions and declining deliverability, both Lower-48 and Canadian sources will struggle to keep production stable at the current levels.

- Expectations for persistent tight market conditions are not a negative reflection on the natural gas resource base – domestically or worldwide. Ample resources of natural gas exist to meet demand for generations to come. However, the U.S. industry is severely restricted in terms of exploring for, producing and delivering natural gas, and severe restrictions are likely to remain.

- The Expected Supply scenario projects much greater supply diversity in the future, including major contributions in the form of Alaskan natural gas and LNG. Delays or denials of these sources will shift supply to more expensive marginal sources of domestic natural gas.

- The lack of a contribution in the Existing Policies scenario from new LNG operations and Alaskan gas most likely would occur as a result of environmental opposition to the siting and construction of new facilities. However, failure to construct these new facilities would result in a far greater reliance on Lower-48 sources of supply, increasing the need to drill in both onshore and offshore areas, which also will be subject to environmental concerns.

- The extreme prices of the Existing Policies scenario are the result of not expanding the natural gas infrastructure much beyond that which is in place <u>today</u>. Moving to the Expected Supply (or Expanded Supply) scenarios would require a significant increase in the natural gas infrastructure, including LNG terminals and the Alaskan gas pipeline.

- The outlook for significant natural gas-fired demand growth by electricity generators is unlikely to be altered, particularly prior to 2015, due to increasing use of the vast number of gas units completed over the past five years and the difficulty in siting and constructing coal or nuclear generating units in less than 10 years.

- Natural gas demand will become less predictable as the relative share of total demand attributable to electricity generators increases, while the relative share attributable to the industrial sector declines.

- Increased unemployment, plant closings and the movement of industrial operations overseas have occurred over the past four years, in part in response to higher natural gas prices. The industrial sector will remain the most sensitive sector to tight supplies and high prices.

# III. Natural Gas Demand Overview

Exhibit III-1 depicts future consumption levels of natural gas in 2010, 2015 and 2020 for each of the three scenarios analyzed. Total consumption, which was 22.1 quads in 2003, is projected to reach 25.0 quads in 2010 under the Expected Policies assumptions and 30.5 quads in 2020. Nearly 72 percent of the total growth is attributable to the increasing demand for gas by electricity generators. Despite projected higher natural gas prices, generators continue to use gas because coal and nuclear units run at full capacity and significant additional coal capacity is not available until nearly 2015.

The alternative scenario consumption levels are not dramatically different than the Expected Policies scenario in 2010. However, total consumption in the Existing Policies scenario is 2.7 quads lower than in the Expected Policies scenario in 2015 and 3.6 quads lower in 2020. Consumption levels fall significantly in all consuming sectors in response to far higher prices, including declines of 1.9 quads by electricity generators and 1.0 quads by industrial customers.

Total consumption levels under the Expanded Policies scenario are quite similar in total to the Expected Policies scenario totals throughout the forecast period. However, there is a significant shift in the composition of the total. Consumption by residential, commercial and industrial consumers all increase – by over one-half quad for industrial consumers in 2020 – in response to lower prices. Additionally, more generating options are available to electricity generators as a result of a more diverse generating mix and, as a result, gas consumption by electricity generators falls by nearly 0.7 quads relative to the Expected Policies scenario.

## Exhibit III-1
## PROJECTED NATURAL GAS CONSUMPTION
## QUADS

## IV. ELECTRICITY GENERATORS WILL DRIVE OVERALL GAS DEMAND

**The demand for electricity is projected to increase at a rate slightly less than 2 percent per year.** The overall demand for electricity is driven primarily by the level of economic activity. In recent years, every 1 percent increase in GDP has resulted in a 0.72 percent increase in electricity sales. This GDP elasticity has declined in each decade over the past 50 years and a continued modest decline is projected - to 0.64 percent by 2020. As a result, a modest decline in the rate of growth for electricity sales is projected, falling from the current rate of 2.0 percent per year to 1.8 percent per year throughout the forecast period. Despite this falling growth rate, annual electricity sales of 3,482 billion kWh in 2003 are projected to reach 4,820 billion kWh by 2020, an increase of over 38 percent.

**Electricity generators are expected to account for one-third of U.S. natural gas consumption in 2020 versus less than 20 percent today.** Roughly 4.2 quads of gas were consumed to generate electricity in 2003, 19 percent of total U.S. gas consumption. This market share is projected to increase to 27 percent by 2010 (6.8 quads) and to 33 percent (10.2 quads) by 2020. Thus, by 2020 electricity generators are expected to be the dominant sector in terms of gas demand, with consumption 32 percent greater than that of the industrial sector and 61 percent greater than that of the residential sector.

Today gas is the source of about 15 percent of all electricity generated but this number is projected to increase to 26 percent by 2020. Conversely, 55 percent of all electricity generated today is coal-based but this percentage is projected to fall to 50 percent by the end of the forecast period.

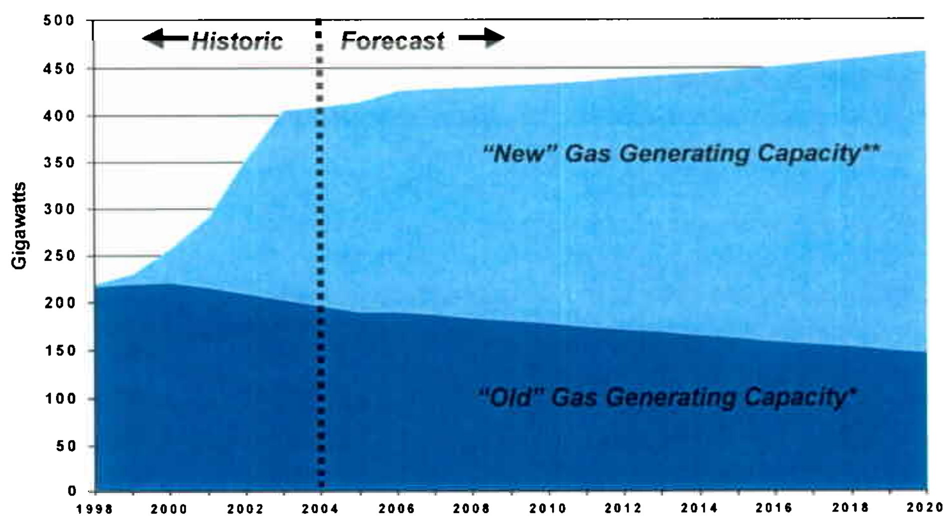
Gas consumption by electricity generators is lower in both the Expanded Policies and Existing Policies scenarios. The reduction in 2020 is 0.7 quads in the Expanded Policies scenario relative to the Expected Policies scenario due to more diversity in the construction of new generating capacity. It is 2.0 quads lower in the Existing Policies scenario in response to dramatically higher gas prices.

**Growth in gas demand for electricity generation will be particularly strong in the Southeast, Intermountain West, Texas and along the West Coast while moderate to weak in the Midwest**. The total projected increase in gas consumption for electricity generation from 2003 to 2020 is 6.0 quads. Of this amount, nearly 75 percent is attributable to the Southeast (1.8 quads), Florida (0.4 quads), Texas (0.8 quads), California/Nevada (0.8 quads), the Pacific Northwest (0.3 quads) and the Intermountain West (0.3 quads). Significant growth is also projected for the Middle Atlantic states, New York and New England, while little or no growth is expected the Midwest (ECAR, MAIN, MAPP and SPP NERC regions). The projected annual growth rates in gas consumption in a number of regions range from 10 to 20 percent for the 1999-2010 timeframe. In addition to the obvious gas supply issues that will be faced in these regions, infrastructure concerns will be critical, particularly for increased pipeline and storage capacity to accommodate more dramatic demand swings.

**Most of the gas-fired generating capacity that will be required in 2020 is already on-line or under construction.** Natural gas clearly has been the fuel of choice for new generating capacity in recent years. In fact, over 90 percent of the capacity added since the mid 1990s has been gas-based. However, somewhat greater diversity is anticipated for new generating capacity in the coming years, including anticipated contributions from both coal and renewable sources. It is projected that 40 percent of the electricity generating capacity added over the forecast period will be natural gas-based. Additionally, there is currently a generating surplus in most regions of the country, and new plant construction has slowed noticeably. Whereas roughly 200 GW of gas capacity was added over the past 5 years, only about half of that amount will be added over the next 15 years. Total gas-fired generating capacity in 2020 is estimated at 466 GW as compared with the roughly 410 GW that is operational today. That is, the gas-based capacity available today is nearly 88 percent of that expected to be operating in 2020.

**Exhibit IV-1**

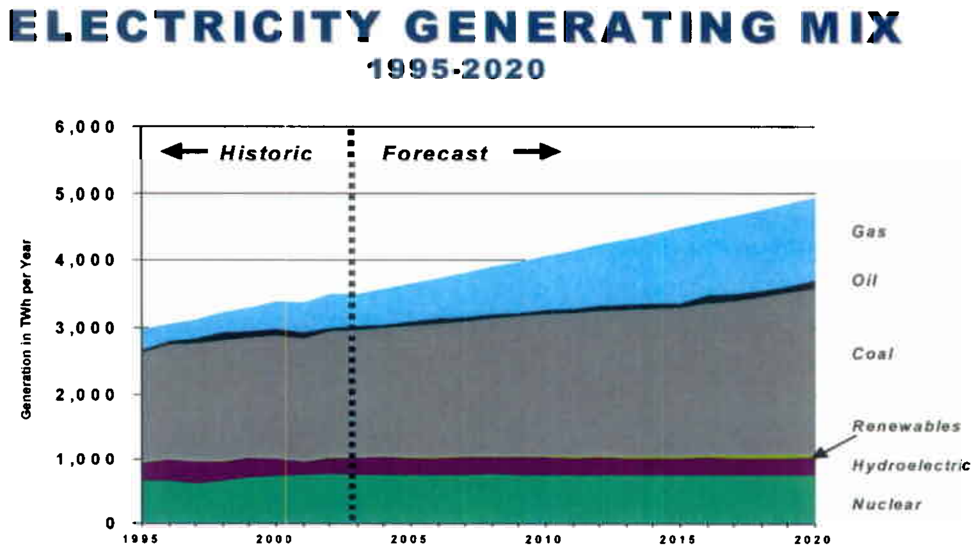
**NATURAL GAS – BASED GENERATING CAPACITY 1998-2020**




* Constructed prior to 1998; primarily boilers, but some combustion turbines and combined cycle units included, operated primarily on natural gas but includes some oil switching capability
**Constructed after 1998;operate almost exclusively on natural gas

This study does not assume significant changes in a number of environmental issues that could have an impact on the composition of electricity generation capacity. For example, the adoption of standards to control mercury (beyond those currently being considered) or $CO_2$ could significantly shift capacity away from coal and toward gas. On the other hand, a proliferation of aggressive renewable portfolio standards could reduce capacity additions for all conventional generating sources. These kinds of policies tend to have major economic and political consequences, and therefore their adoption is considered unlikely. Similarly, obstacles to the re-licensing of nuclear and/or hydro units – which combine to provide 30 percent of our current electricity supply – could have a dramatic impact on gas demand. Based on current trends, denials of a significant number of re-licensing applications were not considered likely.

Exhibit IV-2




**The ability of other fuels to substitute for natural gas in periods of high gas demand continues to decline.** In the mid-1970s there was a fairly high degree of substitutability between gas and oil in the electricity generation sector. Many generating units, particularly boilers, could operate on either gas or oil and it was common to switch from one fuel to the other as their relative economics changed. Additionally, oil and gas boilers tended to operate in an intermediate mode basis with annual capacity factors in the 20 to 40 percent per year range. Thus, if an individual boiler was not capable of switching from one fuel to another that boiler could be shut down and an available boiler could be started up on the competing fuel. The ratio of gas to oil consumed for electricity generation in the mid-1970s was about 50:50.

Changes in equipment and environmental regulations have combined to significantly reduce gas and oil substitutability. Combined cycle units have replaced boilers and although these units may be set up to operate on both gas and oil, most combined cycle units were installed in a gas-only mode to optimize environmental and operating performance. Additionally, oil backup requires the siting and installation of storage tanks. According to the National Petroleum Council, less than 20 percent of the generating capacity installed between 1998 and 2005 will have alternate fuel capability.[1] Further, ozone and other environmental standards preclude the use of oil in many parts of the country at some or all times. The combination of the evolution in equipment coupled with environmental restrictions has reduced gas/oil substitutability. Today, eight times more gas than oil is consumed for electricity generation.

**While the construction of some new coal-fired generating units is anticipated, a modest decline in the contribution of coal to total electricity generation is projected.** Coal-fired generating capacity is projected to increase from the current level of 314 GW to 364 GW in 2020. Based on this projection, coal will maintain just over one-third of total generating capacity over the forecast period. The rate of growth for coal-based capacity accelerates somewhat from 2010 to 2020 relative to the 1999 to 2010 growth rate – 1.0 percent per year versus 0.7 percent per year. Further, capacity additions of roughly 2.0 percent per year are expected after 2015. Coal consumption also is expected to increase over the forecast period, moving from 19.7 quads in 2003 to 24.1 quads in 2020. Despite this growth in both coal capacity and coal consumption, the share of coal in the generation mix is expected to fall somewhat – from 55 percent today to 50 percent in 2020.

Building new coal-fired capacity becomes economic when gas prices exceed roughly $4.50 per MMBtu. However, the lead-time for coal plants is 8 to 10 years. Thus, 33 of the 50 GW of new coal capacity is projected to come on-line after 2015. Additionally, environmental opposition and concerns over controlling $CO_2$ and mercury will continue to deter new construction. The utilization of available coal-capacity will be maximized, and an increase in capacity utilization from 70 percent to 78 percent is projected.

**No new nuclear units are anticipated by 2020 and the contribution to total generation from nuclear sources is projected to fall from 22 percent to 16 percent.** Nuclear power currently provides 22 percent of the U.S. electricity supply. However, under the Expected Policies scenario it is assumed that new nuclear plant construction remains infeasible and therefore no plants will be constructed. As a result, the contribution from nuclear sources is projected to fall to 16 percent by 2020. Nuclear units, similar to coal units, will be run in a full-out baseload mode, with capacity factors in excess of 90 percent. Under the Expanded Policies scenario 2.5 GW of nuclear capacity is constructed toward the end of the forecast period and all plants are run at a slightly higher capacity. As a result of these actions the nuclear share falls to 18 percent rather than 16 percent as in the Expected Policies scenario.

**Despite a five-fold increase in renewable generating capacity, renewable sources are projected to account for only 1 percent of the electricity generated in 2020.** Renewable sources, including wind, solar, biomass and geothermal, provide only 0.3 percent of U.S. electricity today. Renewable generating capacity, driven largely by wind projects, is projected to jump from about 10 GW today to 50 GW by 2020. Based on this forecast, renewable sources will represent 4 percent of the generation capacity in 2020 and 1 percent of the electricity generated. These sources tend to have a much lower utilization factor than do traditional generating modes – typically in the 10 to 20 percent range.

**Additional hydroelectric capacity is not likely.** Hydro capacity is expected to remain flat at 99 GW throughout the forecast period. Hydro provides 8 percent of the total electricity generated today, but this share is projected to fall to 6 percent by 2020. However, the availability of hydro will continue to have important implications for natural gas, particularly on the West Coast where hydro output is a function of snow and rainfall levels and where a lack of hydro translates directly into increased gas demand for electricity generation.

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[1]National Petroleum Council, *Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy,* Volume II, September 2003, p. 90.

## V. INDUSTRIAL NATURAL GAS DEMAND GROWTH WILL LAG SIGNIFICANTLY BEHIND GROWTH IN THE OTHER KEY DEMAND SECTORS

**Natural gas consumption in the industrial sector is projected to increase at an annual rate of 0.3 percent through 2020 – only one-fifth the rate of growth experienced in the 1990s.** Natural gas provides nearly 40 percent of the primary energy consumed in the industrial sector. In the decade of the 1990s, industrial gas consumption exceeded oil consumption in every year. However, oil consumption has exceeded gas consumption since 2001, with a difference of roughly 1 quad in 2003. Industrial coal consumption is about one-fourth that of natural gas or oil.

Gas consumption by industrial customers was 7.4 quads in 2003, a decline of roughly 15 percent from the levels experienced in the late 1990s. During the 1990s, industrial gas consumption increased at an annual rate of roughly 1.5 percent, but significant declines were realized in 2001 and 2003, with a modest rebound in 2002. The Expected Policies scenario projects an industrial gas consumption total of 7.7 quads in 2020, reflecting an annual growth rate of 0.3 percent per year.

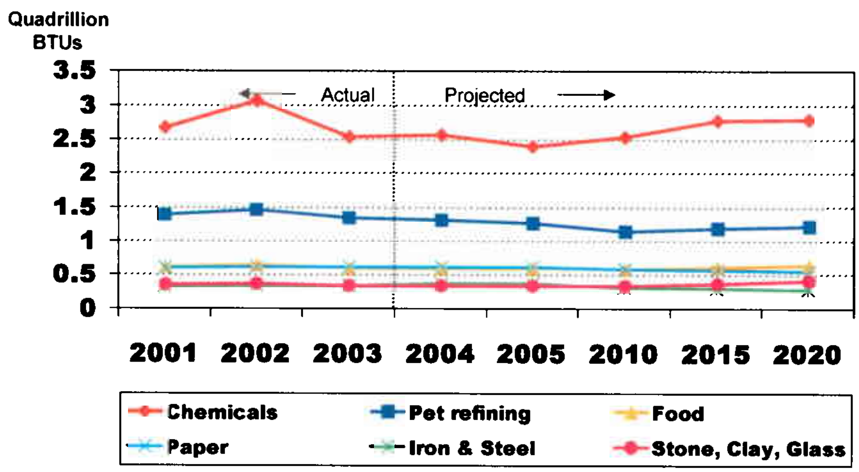
The 2020 projection of the Expanded Policies scenario is roughly a half a quad higher (8.3 quads) than the Expected Policies scenario, while the Existing Policies scenario is about 1.0 quads lower (6.7 quads). These estimates reflect the prices of natural gas in the alternative scenarios relative to those of the Expected Policies scenario.

**The declining market share projected for the industrial sector will result in a less steady national gas load.** The industrial sector accounts for one-third of U.S. gas consumption today, but a decline to 25 percent is forecast by 2020. The industrial sector has not only been the largest single sector in terms of U.S. gas demand, but also it has been the sector with the most stable demand profile. Whereas residential, commercial and electricity generation demand are driven primarily by weather and they therefore exhibit extreme peaks and valleys in demand, major industrial customers often operate 24 hours a day, 365 days a year on a fairly constant gas flow. The load balancing potential of industrial customers is often enhanced through the use of interruptible contracts. Additionally, industrial facilities have traditionally provided economic justification for extending gas mains to areas without gas service, opening the way for residential and commercial gas growth. Local gas utilities deliver over half of the gas consumed by industrial customers.

**Industrial natural gas demand growth will be constrained by limited growth in industrial production, increasing efficiency and global competition.** Although the U.S. gross domestic product is projected to increase at an annual rate of 2.8 percent throughout the forecast period, growth in industrial production is expected to lag behind GDP, increasing at a rate of 2.3 percent per year. The high energy consuming portion of the industrial sector will not grow as rapidly as other segments of the economy, in part because basic manufacturing operations will continue to face higher costs at home and growing competition from other parts of the world. Not only will industrial production lag behind overall economic growth, but also energy consumption in the industrial sector will not even keep pace with industrial growth. The higher energy prices experienced since 2000 will motivate firms to seek out additional energy efficiency measures to further decrease the energy input required per unit of production. To illustrate the magnitude of the improvement in industrial energy efficiency since the first Arab oil embargo, industrial output has doubled since 1973, but the level of industrial energy consumption is virtually identical to what it was 30 years ago.

**Exhibit V-1**

**ACTUAL AND PROJECTED INDUSTRIAL NATURAL GAS CONSUMPTION BY MAJOR INDUSTRIES**




**Although growth in industrial natural gas demand is expected to be lackluster, a continued dramatic decline in this market is not anticipated.** Industrial natural gas consumption dropped sharply from 2000 to 2003 – by over 15 percent. This decline was concurrent with, and in part attributable to, the rapid rise in gas prices. Some plant operators have shutdown their facilities or moved overseas, often citing high gas prices as the sole reason. Feedstock industries were particularly hard hit. Some have argued that only the old, marginally competitive facilities were affected, and that surplus worldwide production capacity, a sluggish worldwide economy and the value of the dollar were the real culprits. Certainly all of these factors contributed. The question is whether or not the downward spiral in industrial demand will continue or whether a rebound is to be expected.

The slow growth projection of the Expected Policies scenario is based on a detailed examination of the key gas consuming industries as summarized below. Hundreds of billions of dollars have been invested in the stock of U.S. gas consuming industrial facilities. For some of these industries, energy costs represent a relatively minor share of the total cost of production. Additionally, it is very difficult to compete from abroad for some industries, such as foods and building products. It is expected that as the national and worldwide economies rebound, so to will these industries and so too will their gas consumption. However, the move toward greater efficiency and/or fuel substitution will only intensify with gas prices in or above the $4 to $5 range, although few major additional efficiency improvements are available and all-time high oil prices limit fuel switching options. The outlook is bleaker for domestic feedstock industries such as ammonia and methanol, whose gas consumption is expected to plummet by about 60 percent between 2000 and 2020.

The major domestic gas-consuming industries tend not to be high growth industries, and energy consumption growth, in most cases, will lag behind industry growth. However, both industrial output and gas consumption will respond to a rebounding world economy.

**Exhibit V-2**

**INDUSTRIAL SECTOR GAS USE, 2002**

| Industry | Percent of Total Industrial Gas Use (%) | Gas Share of Value Added (%) [1] |
|---|---|---|
| Chemicals (all chemicals except ammonia production) | 32 | 13 |
| Ammonia Production | 5 | 80 |
| Refining | 18 | 8 |
| Pulp Paper Production | 7 | 6 |
| Food Processing and Manufacturing | 8 | 3 |
| Iron, Steel, Aluminum, Other Metals | 7 | 6 |
| Stone, Clay, and Glass | 5 | 2 |
| All Other Manufacturing and Non Manufacturing | 18 | 2 |
| All Industrial | 100 | 7 |

[1] The dollar value of natural gas purchased divided by the dollar value of manufactured product.

**The use of gas for boiler and "other" applications is projected to increase, while feedstock applications will experience declining gas usage.** Nearly 80 percent of the gas consumed in the industrial sector is concentrated in six industries – chemicals (2.5 quads), petroleum refining (1.3 quads), paper (0.6 quads), food processing (0.6 quads), iron and steel (0.3 quads) and stone, clay and glass (0.3 quads).

The primary functions of gas are as a boiler fuel (2.4 quads); for other process heating applications (2.5 quads); as a feedstock, particularly for ammonia, methanol and hydrogen (0.6 quads); and for various "other" applications (1.7 quads). The projection shows slow growth for boiler fuel and "other" applications, but declines for gas process heating and feedstock uses.

**Industrial growth in gas consumption is expected to be sluggish in all geographic regions.** Roughly 54 percent of all industrial gas consumption occurs in two geographic regions, the West South Central (2.8 quads in 2003) and the East North Central (1.3 quads). Gas consumption in the West South Central region is heavily concentrated in chemicals and petroleum refining, and this one region accounts for over half of all gas consumed nationally as a boiler fuel or as a feedstock. A growth rate of 0.3 percent annually is projected for gas consumption in the West South Central region through 2020.

Gas consumption in the East North Central region is less than half that of the West South Central and it is distributed primarily between the chemical, iron and steel, food, petroleum refining and paper industries. An annual growth rate of 0.2 percent is projected for this region.

Growth in industrial gas consumption in all other regions is projected to fall in a fairly narrow range from 0.2 to 0.8 percent per year.

**The demand for chemicals will continue to grow worldwide, and U.S. gas consumption will rise modestly in response.** The U.S. chemical industry accounts for about one-fourth of worldwide chemicals production. This industry is energy intensive and natural gas intensive. In fact, it accounts for 11 percent of all U.S. gas consumption – a total of 2,544 TBtu in 2003. Geographically, roughly 60 percent of the gas consumption for chemicals is accounted for by the West South Central region. One-fourth of the industry's gas consumption is as a feedstock, primarily for ammonia, methanol and hydrogen. The other three-quarters are attributable to boilers (32 percent), process heaters (23 percent) and a variety of other uses (22 percent). Similar to other energy intensive industries, energy consumption per unit of production has been reduced significantly in recent years. According to the American Chemistry Council, this reduction has been nearly 40 percent since the mid-1970s.[1]

Plant shutdowns and layoffs in the chemical industry have received much attention since the winter of 2000-2001, and certainly higher natural gas prices have been a contributing factor. Feedstock operations have been particularly hard hit. However, a worldwide economic slowdown and a weaker dollar have also played a part. Chemicals remains a growth industry, with new products and new markets fueling new demand. As a result of this industry growth, natural gas demand also is expected to increase, although slowly. Consumption in 2020 is projected to reach 2,813 TBtu for the industry, reflecting a growth rate of 0.6 percent per year. However, gas consumption for methanol and ammonia production is expected to be cut nearly in half.

**Petroleum refineries are expected to reduce natural gas consumption.** Petroleum refineries consumed 1,347 TBtu of natural gas in 2003, nearly 20 percent of total industrial gas consumption. The refining industry is highly competitive, and many less efficient refineries have been shut down over the past three decades, while no new units have been constructed. Some environmental factors favor increased gas usage at refineries, such as the production of cleaner gasoline that requires hydrogen, for which natural gas is the typical feedstock. However, refineries have multiple energy options for most of their processes and they will move from fuel to fuel depending on relative prices. In addition to readily available fuel switching, refineries will continue to invest in energy efficiency, thereby reducing total energy demand in general and natural gas demand in particular. However, most of the easy energy efficiency opportunities have already been captured and future gains will be less dramatic. An annual decline in gas consumption of roughly 0.6

percent per year is projected for petroleum refining, resulting in a consumption level of 1,218 TBtu in 2020.

**Natural gas consumption by the paper industry will decline as companies attempt to further increase energy efficiency.** Gas consumption by the paper industry is fairly dispersed nationally, but it is particularly strong in the East North Central, West North Central and West South Central regions. Energy is a significant component of total operating costs in the paper industry. Although on-site energy production (primarily cogeneration fueled by wood by-products) supplies about 60 percent of the industry's energy needs, purchased fuels cost the industry roughly $8 billion annually. The paper industry faces significant foreign pressure and it will continue to seek ways to reduce purchased energy costs. It is projected that gas consumption by the paper industry will fall by 0.5 percent per year over the forecast period, declining from 613 TBtu in 2003 to 563 TBtu in 2020.

**Modest growth is projected for natural gas consumption by the food industry.** Natural gas consumption in the food industry is projected to increase at an annual rate of 0.4 percent, moving from 604 TBtu in 2003 to 642 TBtu in 2020. Much of this industry's energy consumption takes place in the East North Central and West North Central regions. Energy costs in the food industry are less than 1.5 percent of the value of total shipments and the industry is therefore less sensitive to price movement than are some other industries. Natural gas is also considered a premium fuel due to its cleanliness – a primary concern in this industry. Moderate growth is predicted for the food industry as a result of increasing population and disposable income, and foreign competition is not as significant a concern as it is in many other industries.

**The growing demand for housing products and limited foreign competition will increase the natural gas demand of the stone, clay and glass industry.** Energy is consumed in the stone, clay and glass industry primarily for the manufacturing of housing construction products – brick, concrete, gypsum, lime – as well as for various container products. Nearly 40 percent of the gas consumption in this industry occurs in the East North Central and South Atlantic regions. Transportation costs are relatively high in this industry relative to the value of the product, and thus foreign competition tends to be a less significant issue, as production near the actual market served is critical. Gas consumption in the stone, clay and glass industry is projected to increase at a rate of 1.0 percent per year, higher than the growth rate projected for any of the other primary industrial gas consumers. National gas consumption is projected to reach 417 TBtu by 2020 as compared to 350 TBtu in 2003.

**Multiple factors will act to reduce natural gas consumption by the steel industry.** Gas consumption by the steel industry is projected to fall at a rate of 1 percent per year, from 348 TBtu in 2003 to 293 TBtu in 2020. A number of factors suggest declining gas consumption, including: high energy intensity resulting in significant price sensitivity; a move towards minimills that tend to use less energy and relatively more electricity; excess production capacity worldwide; and, aggressive foreign competition. Energy costs account for about 15 percent of the total cost of manufacturing steel.

[1]National Petroleum Council, *Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy*, Vol. II, September 2003, p. 54.

## VI. MODEST GROWTH AND STIFF COMPETITION ARE ANTICIPATED FOR RESIDENTIAL NATURAL GAS DEMAND

**Natural gas remains the primary energy source in the residential sector, although electricity has made significant inroads.** Natural gas accounts for 45 percent of the energy consumed in the residential sector versus 38 percent for electricity and 13 percent for heating oil. The natural gas share has fallen slightly over the past three decades, down from 49 percent in 1973, while the drop in the share of heating oil has been much more dramatic, falling from 28 percent to 13 percent. In contrast, the share of electricity doubled over the same timeframe, moving from 19 percent to 38 percent.

**Modest growth in natural gas demand is projected for the residential sector.** Residential natural gas consumption reached 5.2 quads in 2003 and an increase to 6.3 quads is projected by 2020. This increase reflects an annual growth rate of 1.2 percent – roughly four times the rate projected for industrial consumption (0.3 percent), but significantly less than that projected for electricity generation (5.0 percent). Residential gas consumption is driven primarily by the weather (assumed to be normal throughout the forecast period), population growth, the share of gas heated homes and gas prices.

In the Expanded Policies scenario residential gas consumption is 1.4 percent higher in 2020 (6.4 quads) than in the Expected Policies scenario. However, in the Existing Policies scenario it is 4 percent lower (6.1 quads), primarily in response to higher prices.

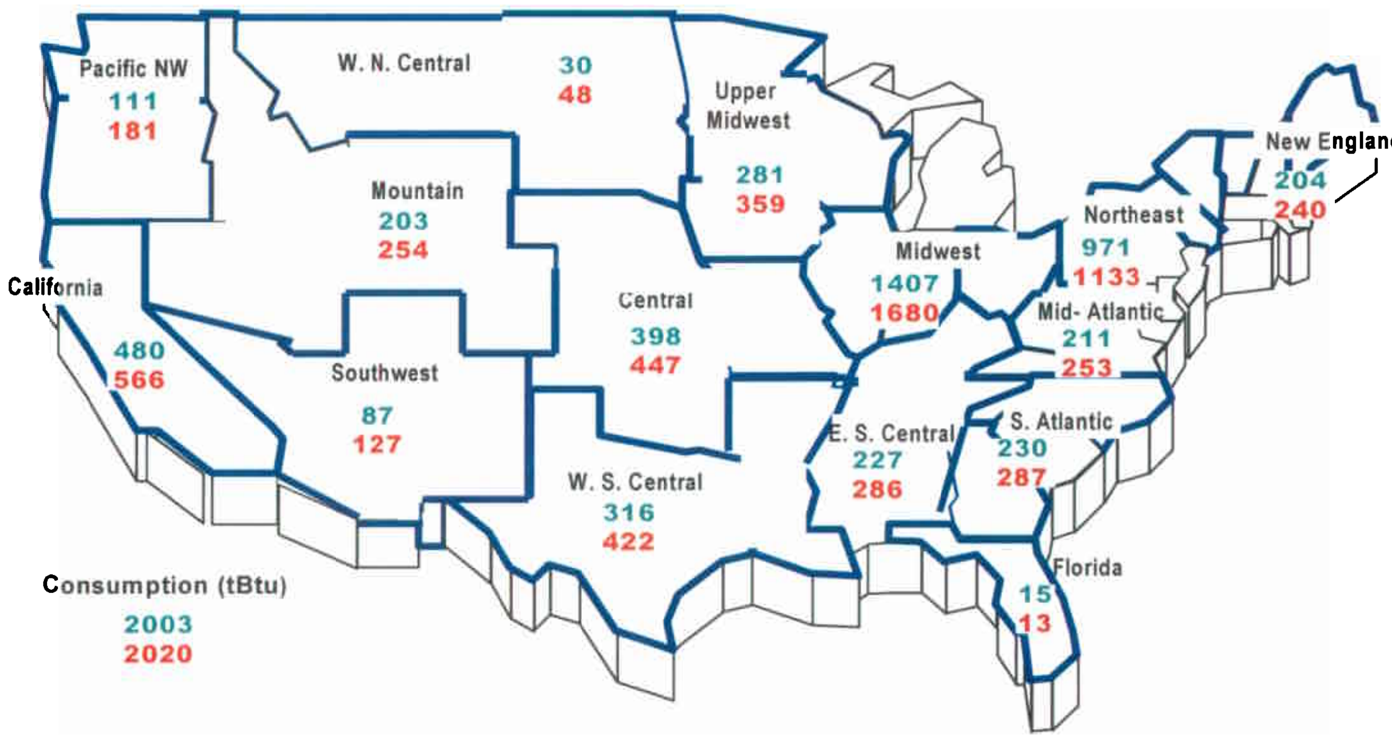
**Growth rates will be higher in the West than in the East and Midwest.** Residential gas demand growth is projected to be near or above 2 percent per year in parts of the West and Northwest, but near or below 1 percent annually in the Northeast, Middle Atlantic and Midwestern states. These projections reflect anticipated population shifts and new (larger) home construction.

**Natural gas consumption per customer will continue to fall, but at a decreasing rate.** Although the number of gas customers in the U.S. increased by nearly 33 percent between 1980 and 2001, overall consumption increased very little because of increased energy efficiency. The average use per residential gas customer (weather normalized) was 109 MMBtu per year in 1980, but only 85 MMBtu per year in 2001. Over half of this dramatic reduction is attributable to more efficient appliances and about one-quarter is due to tighter homes. The remainder is due to a variety of demographic and miscellaneous factors.[1]

It is expected that the average use per customer will continue to fall throughout the forecast period, but at a slower rate – roughly 0.5 percent per year versus the 1 percent annually experienced since 1980.[2] Two principal factors will tend to moderate the decline. First, the oldest and most inefficient appliances have already been replaced and potential improvements in new equipment are more modest. Second, consumers are demanding larger homes, thereby increasing the heating load. There is also a potential to reverse the use-per-customer trend as gas customers, similar to electricity customers, demand more and different energy related products - such as gas fireplaces and gas grills.

## Exhibit VI-1

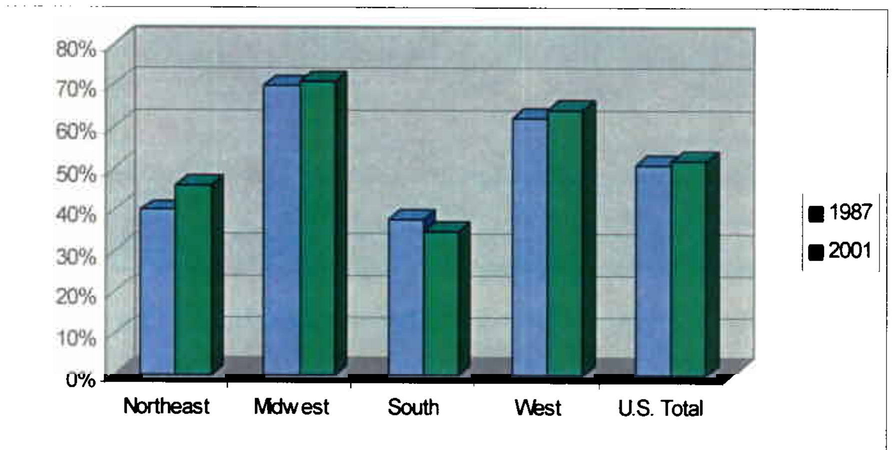
## ACTUAL AND PROJECTED RESIDENTIAL NATURAL GAS CONSUMPTION BY REGION, 2003-2020



**Competition for market share in the residential sector will be intense, particularly in warmer climatic areas, rural areas and in the smaller homes market.** While electricity competes with natural gas in traditional markets – space heating, cooking, water heating and clothes drying – much of the growth in the electricity share is attributable to the proliferation of devices that only operate on electricity, such as computers, televisions, VCRs, DVDs, stereos, and the like. Natural gas remains very successful in the traditional markets, with market shares just over 50 percent for both space and water heating, 35 percent for cooking and 22 percent for clothes drying.[3]

**Exhibit VI-2**

**RESIDENTIAL NATURAL GAS SPACE HEATING MARKET SHARES BY REGION, 1987-2001**

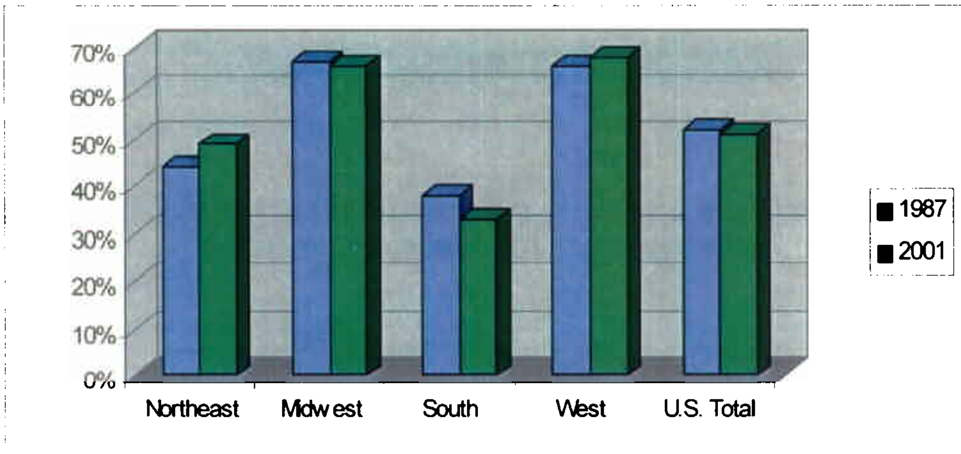



Source: American Gas Association, *Residential Natural Gas Market Survey*.

Market shares for the four primary energy applications have been quite steady on a national basis in recent years, although there has been variability among the geographic regions. Natural gas market shares in the Northeast increased from 1987 to 2001, from 40 percent to 46 percent for space heating and from 44 percent to 49 percent for water heating. In contrast, in the South the market share for gas fell: from 38 percent to 35 percent for space heating, from 38 percent to 33 percent for water heating, and from 26 percent to 22 percent for cooking. Gas market shares in the West have increased for all four applications – space heating (62 percent to 64 percent), water heating (66 percent to 68 percent), cooking (39 percent to 42 percent), and clothes drying (27 percent to 31 percent). Gas market shares in the Midwest have been high and increasing for space heating (70 percent to 71 percent), and high but slightly decreasing (by 1 or 2 percentage points) for each of the other three applications.

**Exhibit VI-3**

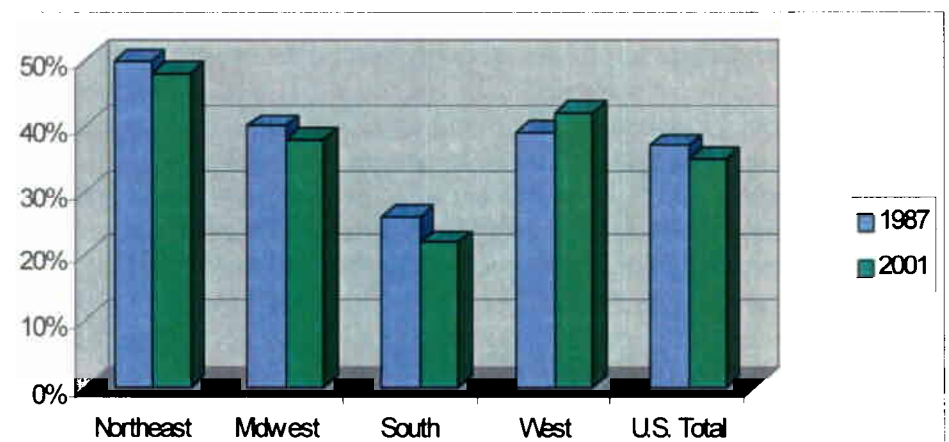
## RESIDENTIAL NATURAL GAS WATER HEATING MARKET SHARES BY REGION, 1987-2001




Source: American Gas Association, *Residential Natural Gas Market Survey*.

**Exhibit VI-4**

## RESIDENTIAL NATURAL GAS COOKING MARKET SHARES BY REGION, 1987-2001

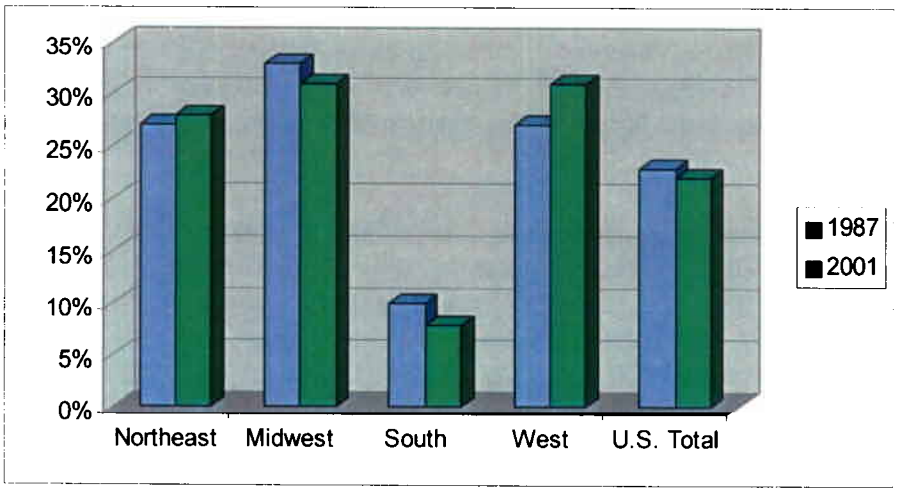



Source: American Gas Association, *Residential Natural Gas Market Survey*.

In the space heating market, the increased efficiency and reliability of the electric heat pump will continue to put pressure on natural gas in warmer climates. This has historically been the case, particularly in the South Atlantic states. However, advances in heat pump technology will

**Exhibit VI-5**

**RESIDENTIAL NATURAL GAS CLOTHES DRYING MARKET SHARES BY REGION, 1987-2001**




Source: American Gas Association, *Residential Natural Gas Market Survey.*

continue to expand the geographic areas where it is most competitive, both northward and westward. Electricity also will be very competitive in smaller, less expensive and space-constrained homes where gas presents incremental cost and space requirements relative to electricity. Gas has made significant inroads versus heating oil in the Northeast, and further gains are anticipated as gas pipeline and distribution systems expand. Gas will remain strongly preferred in colder climates where space heating is paramount.

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[1]American Gas Association, *Patterns in Residential Natural Gas Consumption, 1997-2001*, June 16, 2003, p. 2.

[2]American Gas Association, *Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020*, September 2004, p. 1.

[3]American Gas Association, *Residential Natural Gas Market Survey*, March 2004, pp. 13-14.

# VII. COMMERCIAL SECTOR GAS DEMAND GROWTH WILL MIRROR THE RESIDENTIAL SECTOR – STEADY BUT UNSPECTACULAR

**Natural gas accounts for 40 percent of the energy consumed in the commercial sector.** The natural gas share of commercial sector energy consumption has fallen somewhat since 1973 – from 45 percent to roughly 40 percent today. On the other hand, the electricity share rose from 26 percent of the total to 45 percent over the same timeframe. Oil has fallen off sharply, with a reduction in share from 27 percent to 8 percent.

Lighting is the largest single energy-related application in the commercial sector. Space and water heating energy consumption combined is approximately equal to the total required for lighting. Gas has a 2:1 advantage in market share relative to electricity for space heating and the two are roughly equal for water heating. Gas has a modest advantage in market share for cooking.

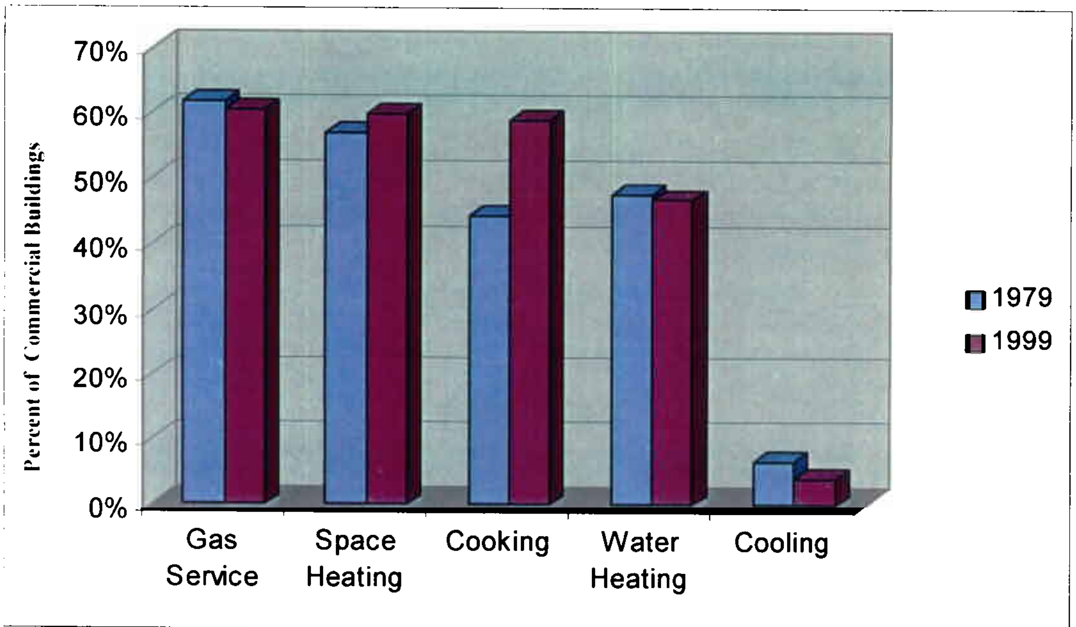
**Commercial sector natural gas consumption is projected to increase by less than 1 quad over the forecast period.** Commercial sector gas consumption is projected to increase by roughly 0.7 quads over the forecast period – moving from 3.3 quads in 2003 to 3.9 quads in 2020. This represents an annual growth rate of 1.1 percent, only marginally below the 1.2 percent rate forecast for the residential sector. The share of total gas consumption accounted for by commercial customers falls from 15 percent in 2003 to 13 percent in 2020.

Projected commercial sector consumption in the alternative scenarios responds in a fashion similar to the residential sector– driven primarily by gas prices – although the commercial response is about twice as great as the residential response. The commercial consumption level of 3.6 quads in the 2020 Existing Policies scenario is 8 percent lower than in the Expected Policies scenario. Conversely, the 4.1 quads projected in the Expanded Policies scenario are 3.3 percent higher than the Expected Policies projection.

**Similar to the residential sector, the commercial sector has exhibited a dramatic increase in energy efficiency.** Although the number of commercial gas customers jumped by 46 percent in the 1980s and 1990s, total consumption rose by only 20 percent. The average use per commercial customer fell by roughly 18 percent from 1979 through 1999.[1] Thus, consumption per customer, again similar to the residential sector, has been falling by about 1 percent annually. There has been significant variation in the use per customer trend on a regional basis. Use per customer in the Northeast increased by 47 percent due to increases in floor space and penetration by gas heating. However, in the Midwest and South respectively, declines of 27 percent and 30 percent were observed. The decline in the West was 18 percent, equal to the national average. A second measure of commercial energy efficiency is gas consumption per square foot of commercial space. This yardstick also indicates a dramatic decline over the past two decades, falling by 40 percent nationally.

**Exhibit VII-1**

**NATURAL GAS MARKET SHARE IN COMMERCIAL BUILDINGS 1979-1999**




Source: American Gas Association, *Trends in the Commercial Natural Gas Market.*

Newer and more efficient equipment, particularly for space and water heating, is responsible for over half of the reduction in use per customer. The remainder is largely attributable to more insulation, better windows and other building "envelope" improvements. A decline in the rate of reduction in consumption per customer is anticipated as these appliances approach their maximum efficiency.

**Natural gas will not compete for many of the growth applications in the commercial sector.** The strongest growth in terms of energy consumption for commercial sector applications is projected for various electrical devices – computers, copiers, imaging equipment and telecommunication devices. Annual growth rates for some of these applications are expected to be above 4 percent.[2] In contrast, the growth rate for many applications for which gas competes are projected in the 1 to 1.5 percent per year range. New applications, such as on-site electricity generation, offer some potential for greater gas growth.

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[1]American Gas Association, *Trends in the Commercial Natural Gas Market*, October 23, 2002, p.1.

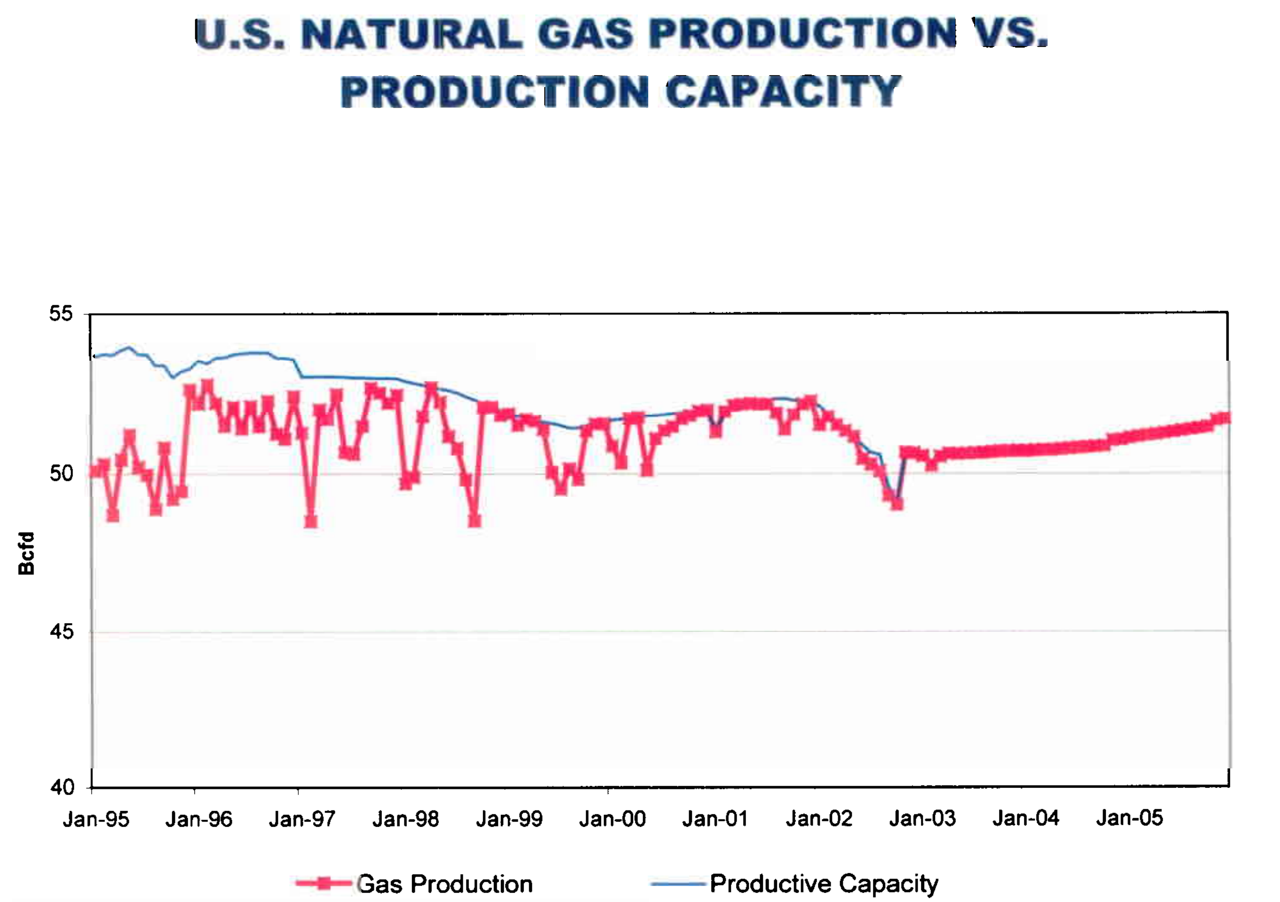
[2]U.S. Energy Information Administration, *Annual Energy Outlook, 2004*, January 2004, p. 5.

# VIII. NATURAL GAS SUPPLY OVERVIEW

For much of the 1990s, U.S. natural gas markets were said to have excess supply, often described as a "bubble." In both the United States and Canada, natural gas production capability exceeded the requirements for produced gas even during most periods of peak demand. For purchasers of natural gas, the result was stable acquisition prices that were relatively low. In addition to North American supplies, liquefied natural gas (traded internationally) provided one to two percent of the natural gas consumed in the U.S.

Quite demonstrably since 2000, the relationship between producible natural gas and requirements for gas supply changed. The market today is often characterized as "tight" (supply strains to meet demand) or as supply-constrained - that is, domestic gas production is at or near 100 percent of production capability.

Exhibit VIII-1




Source: Energy and Environmental Analysis.

The tight market for U.S. gas production compared to demand requirements is not likely to change in the near-term. Sustaining natural gas production in the U. S. or growing it modestly presents significant challenges to gas producers, as well as to policy makers who have a strategic role in the future development of domestic natural gas resources.

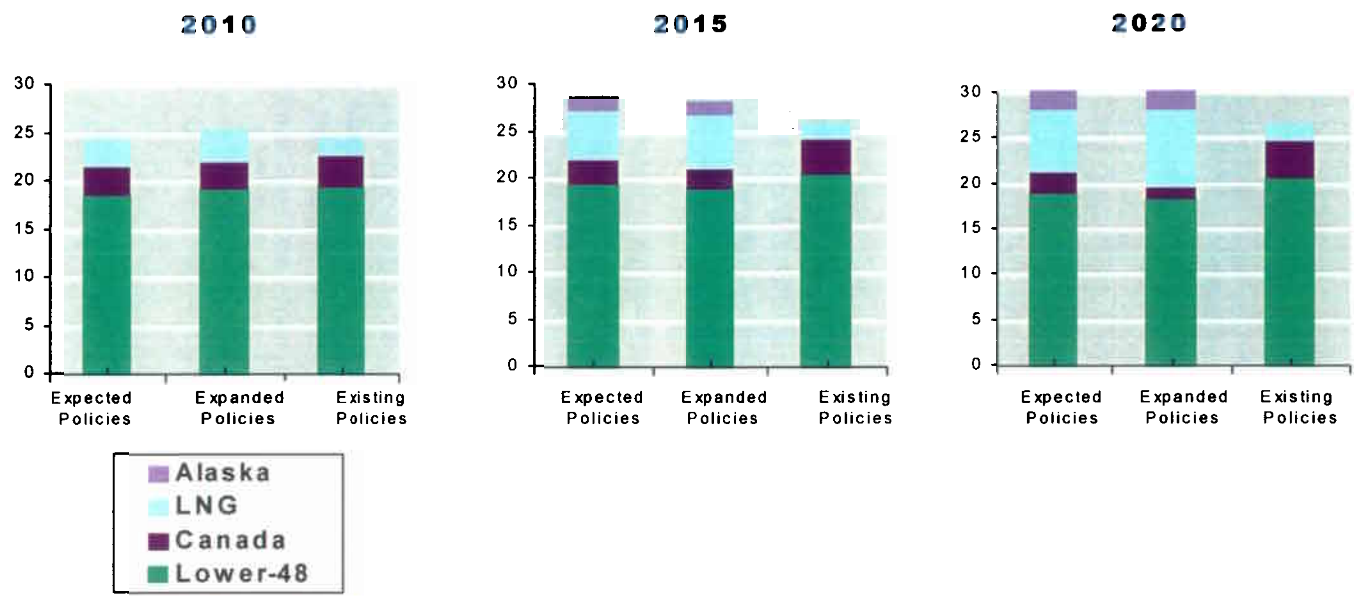
Exhibit VIII-2 shows key natural gas supply sources for the U.S., including Lower-48 states production, gas from Alaska, Canada and internationally traded LNG, and their estimated contribution to U.S. natural gas supply out to 2020. Each of the three scenarios - Expected Policies, Expanded Policies and Existing Policies - is shown in the exhibit. Each supply source is examined more closely in the following sections of this report.

In the Expected Policies scenario, Lower-48 production varies from 19.1 quads to 19.4 quads annually from 2010 to 2020. Offshore moratoria essentially stay in place and portions of federally owned land in the Intermountain West remain restricted. Nominal gas prices fluctuate between $5.30 and $8.15 per MMBtu and LNG followed by Alaskan gas (after 2013) meet incremental growth in demand. With a total market over 30 quads by 2020, Lower-48 supplies account first for about 81 percent of U.S. gas consumption in 2005, declining to 61 percent in 2020.

Under the Expanded Policies scenario, steps are taken to lift offshore moratoria and to open more areas of the Intermountain West to drilling. Roadblocks to LNG and Alaskan gas development also are overcome, resulting in the greatest estimate of these critical supplies among the three scenarios. With these sources of gas supply available, acquisition prices fall compared to the Expected Policies scenario to a nominal value of about $5.47 per MMBtu by 2020. This results in a slightly smaller contribution of Lower-48 gas to the whole (about 60 percent in 2020) because lower prices do not support some of the more expensive domestic sources of gas compared to LNG and reserves in Alaska, once the pipeline infrastructure is in place.

The Existing Policies scenario produces a different result. Under this scenario, neither new LNG terminals nor an Alaskan pipeline are constructed. Thus, domestic production is left to meet more of a smaller overall gas market (just under 27 quads annually). Prices rise to $13.76 per MMBtu in 2020, which supports Lower-48 production that still accounts for 77 percent of gas consumption. The irony is that, for reasons of environmental protection and security, less LNG is made available to the market, Alaskan gas is eliminated and, therefore, more drilling occurs in the Lower-48 states, particularly in tight sands and coal seams – activities that also raise environmental flags.

## Exhibit VIII-2
## PROJECTED NATURAL GAS SUPPLY QUADS



# IX. LOWER-48 SOURCES WILL ACCOUNT FOR A DECLINING SHARE OF OUR TOTAL NATURAL GAS SUPPLY

**Even with substantial natural gas resources in the ground, merely sustaining annual gas production will challenge domestic producers.** Estimates of annual Lower-48 gas production in this report (for all three scenarios) only vary 2.3 quads, from 18.3 to 20.7, for the period 2005-2020. Why? The Potential Gas Committee (Colorado School of Mines) estimates that over 1,200 Tcf of natural gas exists *in the ground* onshore and under the coastal waters of the United States (including Alaska). At current rates of production (approximately 19 Tcf annually) that is more than 60 years of natural gas resource development. In fact, even that number is not static and is likely to grow. However, very limited growth (or decline for that matter) in Lower-48 states production is forecast in this study.

The National Petroleum Council (NPC) report on natural gas released in 2003 noted that only 14 percent of its assessed North American resource base was proven, that another 17 percent could be attributed to field growth associated with known reserves and that a full 69 percent was still undiscovered. Admittedly, there is a great deal of uncertainty associated with our knowledge of the ultimate volume of natural gas to be recovered. That said, virtually all estimates of natural gas resources in North America are large. With all of this gas in the ground, why isn't future gas production expected to grow?

The answer lies primarily in the type of well being drilled today (and likely to be drilled in the future) and the locations available for gas and oil development. America is in the midst of a drilling boom. Rig activity in the U.S. has been sustained above 1,000 total rigs operating for more than a year. Operations in search of natural gas targets routinely account for 85 percent of all rig activity and as many as 20,000 wells are completed annually to be added to the current inventory of over 350,000 producing gas wells. All of those indicators are good. But a not-so-subtle change in quality and productivity of individual producing wells is also occurring.

Exhibit IX-1 shows some of the current trends. For example, rig counts have been rising with gas-directed operations growing from 55 percent of total activity to over 80 percent of total activity. Gas well completions have increased, particularly since 1999, but discoveries per well have flattened or decreased. This is typical when well completions increase dramatically, inasmuch as some marginal prospects are drilled along with better prospects during periods of price induced higher activity.

## Exhibit IX-1

## RIG COUNT, WELLS AND DISCOVERIES

| Year | Annual Avg. Rig Count | Annual Avg. Gas Rigs | Percent Gas Rigs | Gas Wells Completed | Total Discoveries (Bcf) | Additions per Well (Bcf) |
|---|---|---|---|---|---|---|
| 1994 | 775 | 427 | 55 | 9,538 | 12,315 | 1.291 |
| 1995 | 723 | 385 | 53 | 8,354 | 10,961 | 1.312 |
| 1996 | 779 | 464 | 60 | 9,302 | 12,318 | 1.324 |
| 1997 | 943 | 564 | 60 | 11,327 | 15,648 | 1.381 |
| 1998 | 827 | 560 | 68 | 11,144 | 11,433 | 1.026 |
| 1999 | 625 | 496 | 79 | 10,877 | 10,807 | 0.994 |
| 2000 | 918 | 720 | 78 | 16,455 | 19,138 | 1.163 |
| 2001 | 1,156 | 939 | 81 | 22,083 | 22,758 | 1.031 |
| 2002 | 830 | 691 | 83 | 16,155 | 17,795 | 1.102 |
| 2003 | 1,032 | 872 | 84 | 19,722 | 19,288 | 0.978 |

Source: Energy Information Administration, U.S. Department of Energy.

In addition, higher gas prices at the wellhead tend to support producer efforts to completely recover gas in areas where it is known to exist. Drilling in these mature areas presents less risk to producers but also leads to less volume recovered per well because the typical reservoir size declines. In addition, technology allows reservoirs to be drained more quickly and efficiently, which is an important factor in making these natural gas reservoirs economic to develop, but which also contributes to shorter reservoir life. This, in turn, requires producers to drill more to replace the decline in volume as reservoirs deplete. And so the cycle, or "treadmill" as it is often referenced, continues. This is happening in the mature areas of the Gulf of Mexico, onshore U.S. and Canada.

**Gulf of Mexico gas production will decline as a portion of all North American gas production, particularly after 2010.** Gulf of Mexico gas production, which was 30 percent of U.S. gas production in 1990, was only 23 percent of gas production in 2003. New frontier gas, primarily from deepwater, has to some extent offset declines in shallow water continental shelf production. However, even recent deeper drilling on mature shallow water leases (enhanced by royalty relief) coupled with deepwater gas will not compensate for the decline in traditional shelf production. During the period 2010 to 2020 this condition is expected to deteriorate further. Other gas sources will need to be more fully exploited in order to sustain overall Lower-48 production.

**An increasing dependence on unconventional gas sources will increase a drilling focus in the Intermountain West, with lower producing but longer-lived wells.** One activity offsetting the high decline rates and recovery factors of traditional sandstone and other reservoirs is the activity in less traditional reservoirs such as tight sands and coal seams. The NPC study of 2003 estimated that over half (55 percent) of the remaining *conventional* resource base in North America is located in the Gulf of Mexico, Western Canada Sedimentary Basin and Alaska. Only four percent of the conventional resource was attributed to the Intermountain West.

In contrast, 44 percent of the yet to be developed *unconventional* resource is expected to be found in the Intermountain West. It is generally recognized that a substantial portion of the total U.S. natural gas resource base is tied up in low permeability (perm) reservoirs such as Devonian Shale and coal seams in the Appalachians, shallow coals in Kansas (and other locations in the mid-continent) and tight sands and coals in the Rocky Mountains. Estimates of unconventional resource volumes vary but they are large for technically recoverable gas.

Advanced Resources International estimates that unconventional resources may total 760 Tcf. In addition, so-called unconventional sources of gas account for over a quarter of U.S. production today and they may account for more in the future.

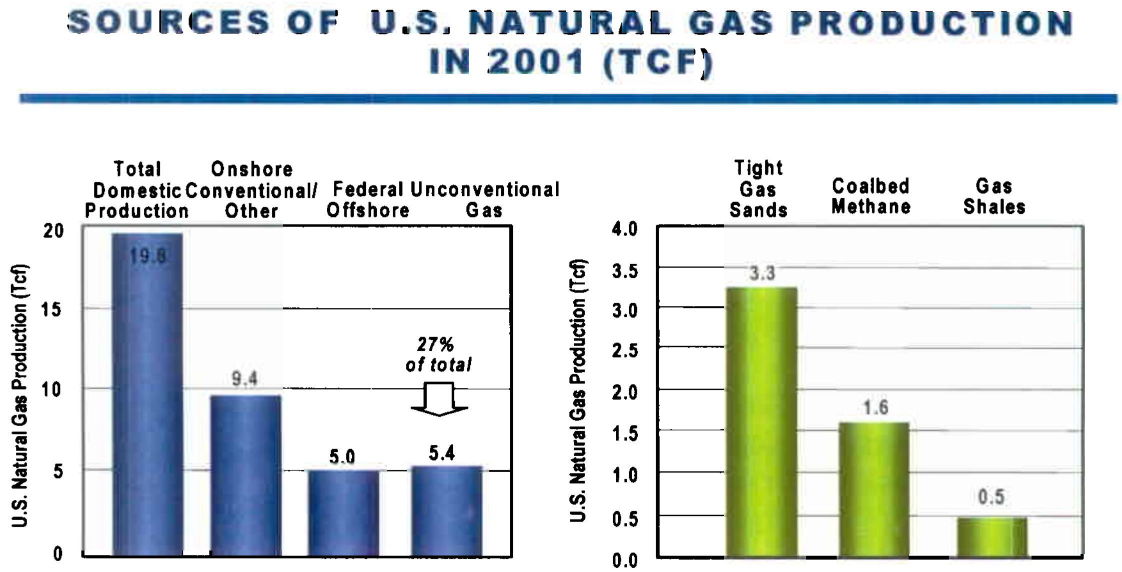
**Exhibit IX-2**

**ESTIMATES OF TECHNICALLY RECOVERABLE U.S. UNCONVENTIONAL GAS RESOURCES**

| | Current Technology (Tcf) | | | Year 2025 Technology (Tcf) |
|---|---|---|---|---|
| | Proved Reserves/ Production | Undeveloped Resource | Ultimate Resource | Ultimate Resource |
| Tight Gas Sands | 149 | 292 | 441 | 520 |
| Gas Shales | 13 | 62 | 75 | 90 |
| Coalbed Methane | 29 | 95 | 124 | 150 |
| **TOTAL** | **191** | **449** | **640** | **760** |

*Source: Advanced Resources Int'l.*

## Exhibit IX-3




Source: Advanced Resources Int'l.

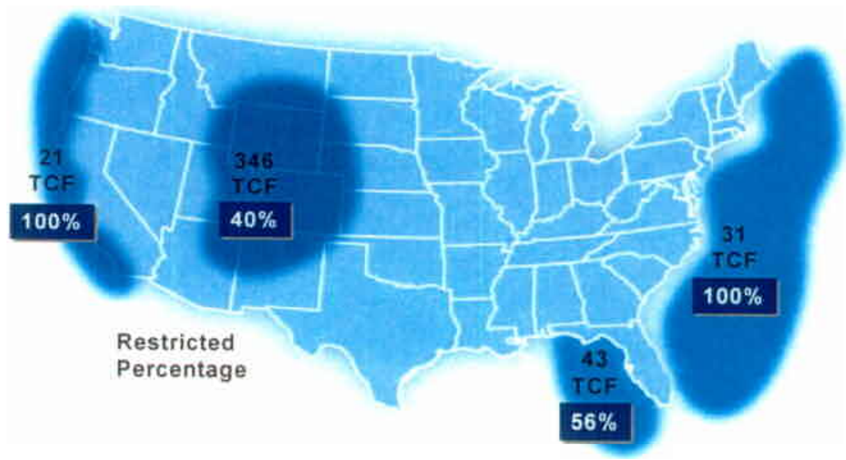
Unconventional gas resources are noted as such only because the geologic setting from which they originate is different from more traditionally productive sources of gas. Technology has been a key factor in permitting gas to be recovered from these sources and to be produced in commercial quantities. But low permeability reservoirs behave differently than sandstone high perm reservoirs. If a high perm reservoir produces at millions of cubic feet per day initially, a low perm reservoir produces at tens or possibly hundreds of thousands of cubic feet per day – often at one-tenth or less a high perm well. Therefore, to maintain the same initial production capability as traditional reservoirs, 10 or more coal seam or tight sand wells may need to be drilled. On a positive note, however, wells drilled and produced from less conventional reservoirs often produce for 15, 20 or even 30 years, albeit at more modest annual volumes. That said, the baseline of production that is established in these fields helps to support the long-term production capability of national natural gas inventories.

An example of recent success in an unconventional play where producing rates have improved significantly is that of the Jonah and Pinedale Fields in southwestern Wyoming. In 1995, the fields in aggregate produced 8 MMcf per day of natural gas from low permeability tight sands. Today, they produce over 1 Bcf per day (over a 100-fold increase) and remain prospective for additional production increases. It is estimated that 700 producing wells may grow to 2,500 successful wells in the future. A combination of new applications of well fracturing techniques, well spacing and 3D seismic has given field operators an opportunity to maximize economic recovery of the gas in-place – estimated to be over 6 Tcf.

**A significant portion of the domestic gas resource is restricted from exploration and it is likely to remain so.** Large portions of federally controlled lands and offshore locations are off limits to gas and oil exploration due to congressional moratoria and other land use restrictions. Included are the East and West coast (continental shelf and slope), areas of the eastern Gulf of Mexico and onshore acreage, particularly in the Intermountain West.

**Exhibit IX-4**

**MAJOR PORTIONS OF THE GAS RESOURCE BASE ARE NOT ACCESSIBLE**




Approximately 29 trillion cubic feet (TCF) of the Intermountain West gas resources are closed to development and 108 TCF are available but with restrictions.

Source: National Petroleum Council.

Numerous locations in these areas have natural gas production potential. For example, natural gas discoveries have been made on the coasts of Canada and are, in fact, being produced offshore of the eastern Canada Maritime Provinces. Yet no gas exploration is permitted in East Coast U.S. waters. To date, the political process and positioning of strong environmental advocates have all but ensured that the moratoria on offshore drilling will remain in place for the foreseeable future. Some of these moratoria have been in place for three decades or more, and they do not recognize the significant improvements in exploration and development technology and business practices that are now available and in use.

Some positive developments for natural gas exploration and development have slowly materialized in recent years in the West where large tracts of federally owned and managed lands are designated for multi-use. However, moving the permit process along where there is federal jurisdiction (Bureau of Land Management and Forest Service, for example) is slow.

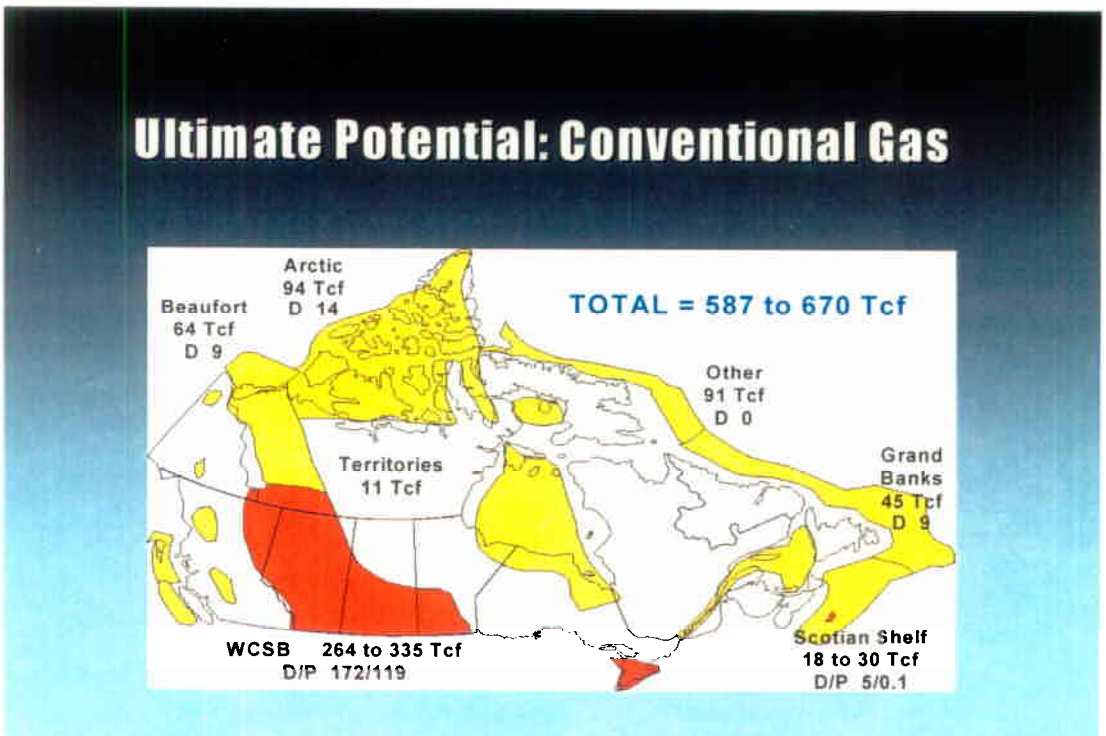
Critical land use and coastal resource management issues have a direct impact on hundreds of Tcf of potential gas resources. An exact estimate of the magnitude of the affected resource is not possible. The fact is that precise gas and oil assessments can only be made when the drill bit is permitted to explore.

**Even with access restrictions and the introduction of new sources of gas supply such as LNG or gas from the Alaskan North Slope, domestic Lower-48 states production is still expected to supply about 60 percent of the gas consumed in the United States in 2020.** Even with what would appear to be a difficult road ahead for E&P investment and land access for gas and oil drilling, Lower-48 states production is expected to be the primary source of U.S. gas supply well into the future. However, because Lower-48 production is expected to remain relatively flat while total supply/consumption continues to grow, the share of total supply accounted for by Lower-48 production will fall. This share was roughly 83 percent in 2003, but in the Expected Policies scenario falls to 77 percent in 2010, 67 percent in 2015 and 61 percent in 2020.

# X. THE TREND OF STEADILY INCREASING NATURAL GAS IMPORTS FROM CANADA IS LIKELY OVER

**Challenges to natural gas supply in Canada are similar to those in the United States at a time when Canadian requirements for natural gas are increasing.** Over the last 20 years, estimates of Lower-48 and Canadian gas resources have grown more than the resource has been depleted. As a result, some analysts view the remaining resource potential today as much higher than it was 20 years ago, despite resource depletion. That is the good news. Prospects for continued growth in "ultimate" resource estimates are in question, however. Western Canadian "ultimate" resource recovery, particularly that based on in-place unconventional resources, needs to be demonstrated by industry activity, which is only in its infancy.

**Exhibit X-1**




Source: National Energy Board of Canada.

Sustaining natural gas production in Canada faces many of the same challenges that exist in the U. S., including declines in well productivity, applications of key technologies to gas sources such as coal seams and the need to invest in costly infrastructure connecting new supply areas to the existing pipeline grid. In addition, Canadian exports to the U.S. will be affected by increasing gas demand within Canada.

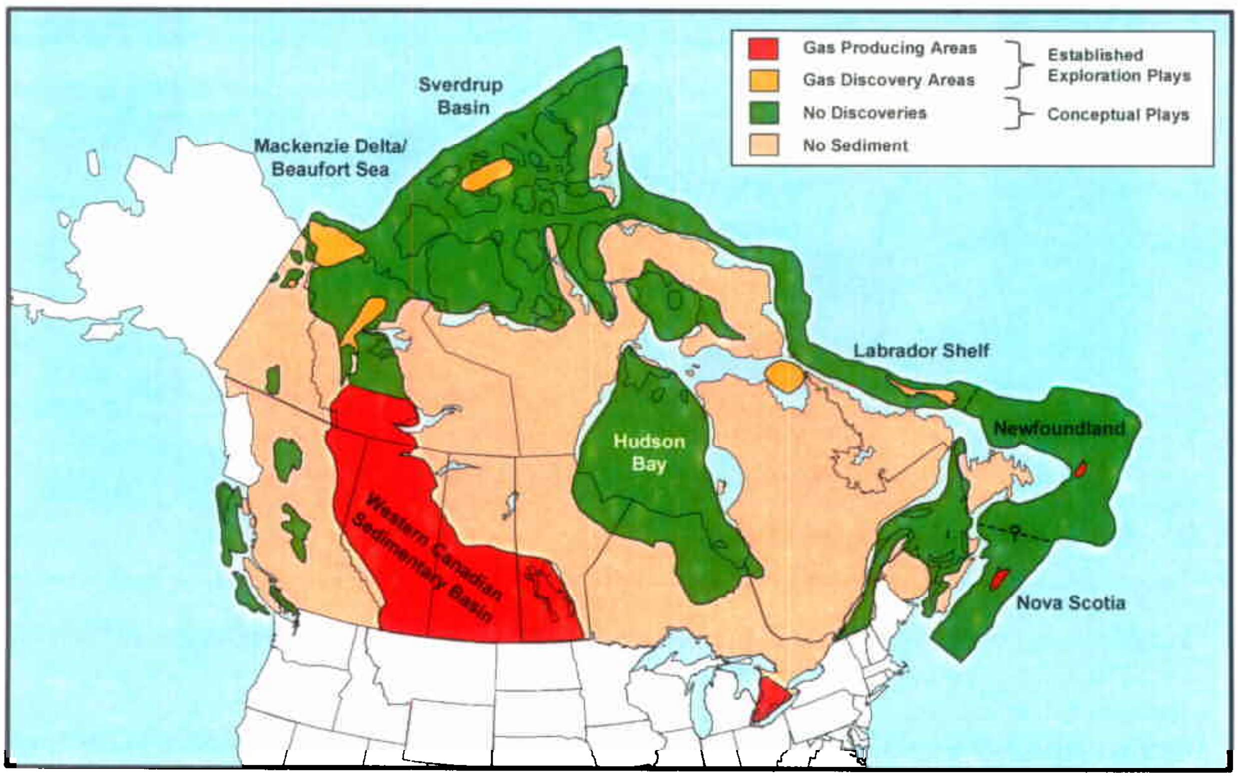
Since the mid-1980s, *marketed* Canadian gas production has more than doubled, reaching 6.4 quads in 2000, which is a quarter of North American gas production. When North American production peaked in 1973, Canada accounted for about 10 percent of North American gas production. However, growth in Canadian gas production has slowed since the mid-1990s.

Looking at the geologic make up of Canada reveals that sedimentary basins *do not* underlie most of the Canadian surface area (onshore and offshore). Almost all of Canadian gas production has come from the Western Canada Sedimentary Basin (WCSB), which underlies most of Alberta, and parts of British Columbia, Saskatchewan, Manitoba, and adjacent regions in the Yukon and Northwest Territories. The remaining production has come from Ontario and recently from Offshore Nova Scotia.

Canada, like the United States, will increasingly turn to frontier regions and less developed unconventional sources of gas (coalbed methane, for example) to maintain natural gas production capable of supporting domestic requirements and exports. However, both the Expected Policies and Expanded Policies scenarios in this report show declining levels of natural gas exports to the U.S. from Canada, particularly after 2010, for primarily the same reasons outlined above.

**Exhibit X-2**

**SEDIMENTARY BASINS IN CANADA**




Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Lower 48 and Canada.*

**By 2020, Canada likely will be exporting less natural gas to the U.S. than it does today.** Several observations work against the notion that Canada will be an endless source of gas supply to U.S. consumers. They are demonstrated in the graphic below, which is based on a forecast of supply and demand for natural gas made by the Alberta Energy and Utilities Board (AEUB) in 2002. First, most analysts believe that natural gas consumption will increase in Canada during the next fifteen years. The most often cited reasons include economic growth, an increasing demand for natural gas to generate electricity, environmental (air quality) issues and increasing natural gas use for enhanced oil recovery (much of that oil for export to the U.S.).

Second, resource depletion impacts are expected to be gripping the largest supply area of Canada, the Western Canada Sedimentary Basin, within the next five years, if they haven't already. The exhibit below shows the anticipated growth of gas demand and forecast for natural gas production declines made by the AEUB specifically for Alberta. Many forecasts of total Canadian demand and production look similar. That is, Canadian natural gas production, which has supported incremental growth in domestic consumption along with significant growth in natural gas exports to the U.S., declines, while domestic consumption of gas in Canada inevitably increases.

**Exhibit X-3**


Source: Alberta Energy and Utilities Board.

Only in the Existing Policies scenario are Canadian gas exports to the U.S. maintained as 13-15 percent of total U.S. consumption. As with the explanation of this phenomenon in the Lower 48 states, environmental or other constraints do not permit the construction of LNG infrastructure.

and the North American supply and demand balance, essentially supply constrained, results in gas acquisition prices in excess of $13.75 per MMBtu by 2020. That encourages the drilling of marginally economic resources in Canada (as in the U.S.) and gas production grows. Of course, this scenario is very dependent on the successful development of other natural gas sources such as methane from coal seams in Canada.

Both the Expected Policies and Expanded Policies scenarios, however, reduce the volume of gas from Canada to the U.S. and reduce the relative level of gas supply in the U.S. attributed to Canada. By 2020, gas imports from Canada fall by 1 Quad annually (accounting for 8 percent of U.S. gas supply compared to 15 percent in 2000) in the Expected Policies scenario and by 2 quads under the Expanded Policies scenario, reducing Canadian contributions to overall U.S. gas supply to only 4 percent. In both cases the difference is made up by LNG imports (some of which may originally land in Canada) and flowing gas from Alaska. Like the explanation offered regarding Lower-48 states supplies, with the addition of significant quantities of imported LNG and other possible frontier sources, gas acquisition prices are reduced so sufficiently that drilling in Canada is not robust enough to offset the depletion impacts on traditional gas reservoirs.

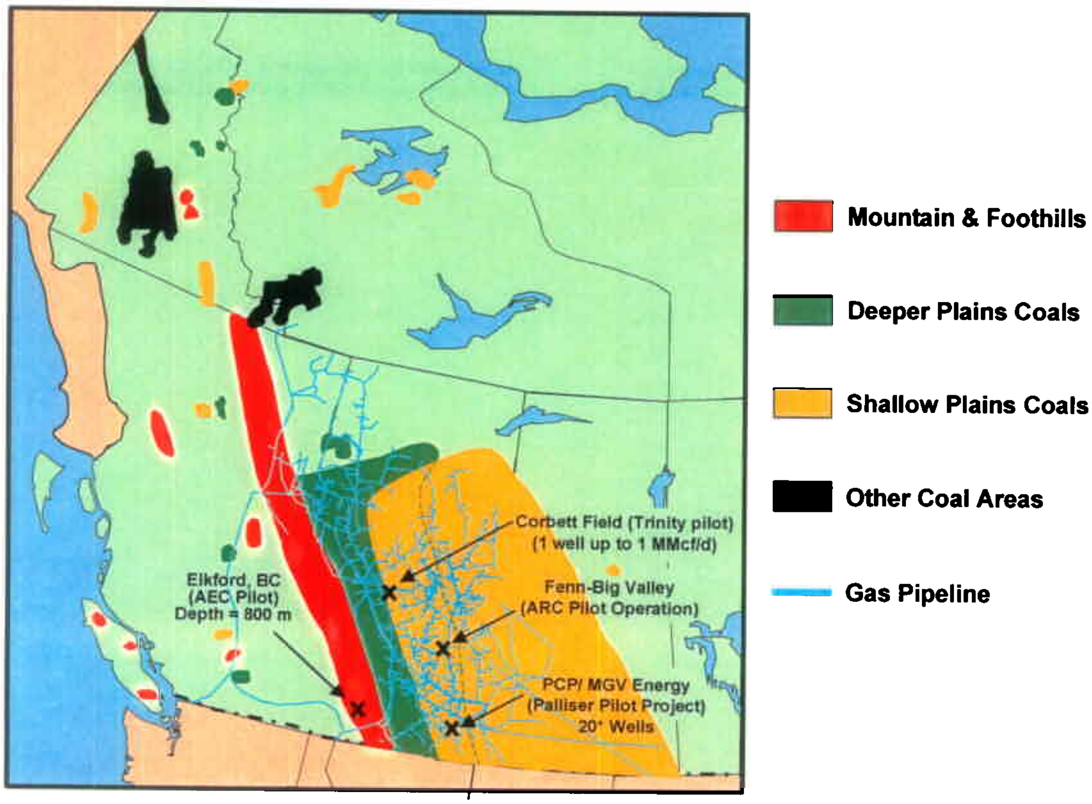
**Unconventional resources of natural gas may become a larger player in Canada's gas supply, but important unconventional sources of oil are likely to require significant quantities of gas for primary and secondary recovery.** There are four general coalbed methane areas in Canada - Shallow Plains, Deeper Plains, Mountains and Foothills - and other coal areas are scattered throughout British Columbia and North of 60°. The Shallow Plains and Deeper Plains coals overlap in Central Alberta. Several coalbed methane projects are active in Western Canada. However, coal rank, which is an indicator of coalbed methane potential, increases moving from East to West. At the same time, the coal resource extends to a greater depth moving East to West. As a result, while the in-place coalbed methane resource increases moving in a westward direction, greater burial depths make recovery of a growing share of this resource uncertain.

Over 350 coalbed methane wells have been drilled in Canada, but there is still little production. In some ways, knowledge of coalbed methane recovery in Western Canada today is comparable to knowledge in the United States in the mid-1980s before significant production developed. More recent attempts to develop methane from coal seams have targeted lower-rank coals, which are more like those currently being developed in the Powder River Basin in the United States. Because of the production experience to date in the United States, Western Canada coalbed methane prospects could develop more quickly.

While estimates of coalbed methane gas-in-place in Western Canada range up to about 2,700 Tcf of gas, a more reasonable estimate at this point in time, and in light of available technology, is much smaller (about 500 Tcf-about 80 percent of which is in Alberta). For the purposes of this report 95 Tcf is viewed as technically recoverable. The fact is that any estimate of coalbed methane production capability remains very speculative until better supported by industry activity.

## Exhibit X-4

### POTENTIAL WCSB COALBED METHANE REGIONS




Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Non-Traditional Gas Sources.*

A complicating factor for natural gas production requirements, particularly in western Canada, is that of the recovery of oil from tar sands in northern Alberta. The United States receives more crude oil and petroleum products (about 2 million barrels per day) from Canada than any other country in the world, including Saudi Arabia, Mexico and Venezuela.

Much of the future of oil production in Canada (billions of barrels) is locked up in tar sands that require a source of heat for steam production or other processes to separate the hydrocarbons from the sediments and bitumen in which they are contained. Estimates of natural gas requirements for these processes vary, but some analysts have speculated that all of the gas associated with a proposed pipeline from the Mackenzie Delta/Beaufort Sea (up to 1 Bcf per day) would be consumed by oil recovery associated with the tar sands. If so, other WCSB natural gas would be made available to domestic and U.S. markets. Nonetheless, the development of oil resources in Canada is expected to be a significant consumer of natural gas in the future.

**Canada may become a focal point of world LNG trade.** Numerous projects for siting LNG regasification facilities have been proposed, particularly in eastern Canada, which could become a part of the burgeoning Atlantic basin LNG trade. Gas imported at these points could serve the Canadian Maritime Provinces, as well as other eastern population centers in Canada and even markets in the U.S. Northeast.

# XI. DOMESTIC NATURAL GAS SOURCES WILL COMPETE WITH LIQUEFIED NATURAL GAS TO SERVE U.S. MARKETS

**The movement toward increased LNG imports has begun.** Liquefied natural gas is renewing itself as an increasingly import factor in U.S. gas markets. There are 113 active LNG facilities in the U.S., including import and export marine terminals, storage and peak-shaving facilities. In 2003, all four marine import terminals were operational (for the first time since 1981) and import levels (over 500 Bcf) doubled the previous record set 24 years earlier. This report projects imported LNG as a source of gas to U. S. customers as high as 28 percent of natural gas supply by 2020 (Expanded Policies scenario). To illustrate the magnitude of LNG operations, the second-largest producer of natural gas in the U.S., ExxonMobil, produced nearly 2.8 Bcf per day in 2003. One large LNG tanker can unload the same volume equivalent in less than 24 hours at the Cove Point, Maryland marine terminal. Simply put, LNG has an enormous potential to supply natural gas to the U.S. pipeline grid.

Even though LNG import facilities received a record volume in 2003, the gas represented less than three percent of all U. S. gas supplies and only 13 percent of all U.S. imports. However, existing import terminals are expanding with regasification capacity expected to increase by nearly 40 percent by year-end 2005 (see Exhibit XI-1). Additional expansions are identified for 2008, which would raise current baseload sendout capacity from about 931 Bcf annually to 1,782 Bcf annually, with even more potential identified in the form of expanded peak-day capability.

This report views expanding LNG capability as inevitable. By adding import facilities primarily in the Gulf of Mexico, the Expected Policies scenario grows LNG imports to 6.8 quads annually, accounting for about 22 percent of U.S. gas supply. Under the Expanded Policies scenario, siting of facilities is even less encumbered and LNG grows to account for 28 percent of U.S. gas supply, or about 8.6 quads annually. Both of these cases act to depress domestic production and imports from Canada slightly inasmuch as abundant LNG supplies push some of the more costly to recover domestic resource out of the market.

Only in the Existing Policies scenario does LNG fail to grow dramatically. Under the conditions of the Existing Policies scenario, no new LNG facilities are constructed due to siting opposition. The result is an LNG contribution to U.S. gas supplies of about 7 percent annually, or 2 quads, which implies that the current planned facilities expansions are the only additions to LNG capacity that are realized through 2020.

## Exhibit XI-1

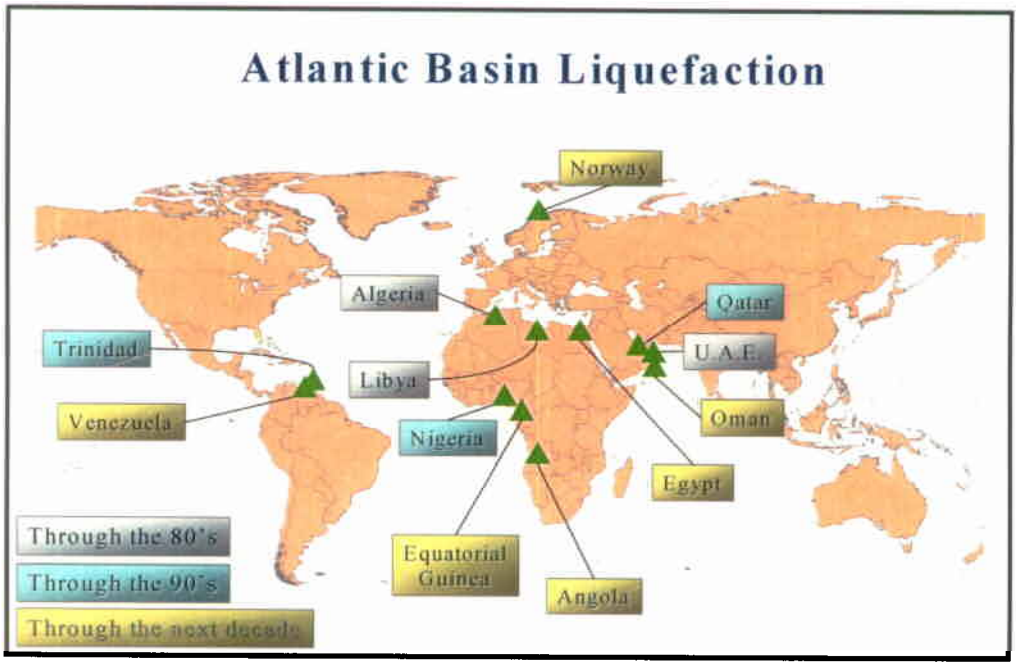
# LNG CAPACITY AND PLANNED EXPANSIONS AT IMPORT TERMINALS

| Facility / Location | Owner | Storage Capacity (Bcf) | Daily Sendout Capacity (Bcf) Baseload | Daily Sendout Capacity (Bcf) Peak |
|---|---|---|---|---|
| **Everett, MA** | Tractebel/Distrigas | | | |
| Existing | | 3.5 | 0.725 | 1.035 |
| **Lake Charles, LA** | Southern Union | | | |
| Existing | | 6.3 | 0.630 | 1.000 |
| Planned Expansion 2005 | | 3.0 | 0.570 | 0.300 |
| Planned Expansion 2007 | | 0.0 | 0.600 | 0.800 |
| **Cove Point, MD** | Dominion | | | |
| Existing | | 5.0 | 0.750 | 1.000 |
| Planned Expansion 2005 | | 2.8 | 0.000 | 0.000 |
| Planned Expansion 2008 | | 6.8 | 0.800 | 0.800 |
| **Elba Island, GA** | El Paso/Southern LNG | | | |
| Existing | | 4.0 | 0.446 | 0.675 |
| Planned Expansion 2005 | | 3.3 | 0.360 | 0.540 |
| **Total Existing Capacity** | | **18.8** | **2.551** | **3.710** |
| **Total Planned Expansion** | | **16.4** | **2.330** | **2.440** |
| **Total with Expansion (2008)** | | **35.2** | **4.881** | **6.150** |

Source: Energy Information Administration, DOE, *U.S. LNG Markets and Uses: June 2004 Update*.

**There are huge volumes of natural gas stranded around the world and many countries are focused on the current *window-of-opportunity* for developing international gas trade.** There are a growing number of countries that are positioning themselves to monetize their otherwise stranded natural gas resources around the world. Some of them, like Venezuela, are in the western hemisphere and quite close to U.S. markets.

**Exhibit XI-2**




Source: Dominion Resources, Inc.

Transportation and distribution of LNG has a record of safe operations worldwide and it appears that current (and foreseeable) acquisition prices for natural gas lands LNG squarely in the competitive supply mix at roughly $3.50-$4.50 per mcf.

**LNG facilities are likely to be constructed and expanded where there is the least public opposition.** The list of competing LNG import facility proposals, once at about 35 announcements, has been reduced to about 27 during the past year. Those that have received regulatory approval include the Sempra Cameron LNG terminal in Hackberry, Louisiana, and the Port Pelican (ChevronTexaco) and Energy Bridge (Exelerate) offshore facilities (Louisiana), which have received licensing from the U.S. Coast Guard and Maritime Administration (MARAD). If even one of the offshore facilities for unloading LNG (Port Pelican or Energy Bridge) is constructed it will be the first of its kind in the world. Onshore LNG projects also have been proposed in Canada, Mexico and the Bahamas. These projects may directly serve U.S. markets or displace domestic gas so more production from these countries (Canada and Mexico) could be exported to the U.S.

## Exhibit XI-3

# PROPOSED LNG TERMINALS

| Name | Location | Owner(s) | Capacity (MMcf/d) |
|---|---|---|---|
| **West Coast** | | | |
| Cabrillo Port LNG | Offshore Oxnard, CA | BHP Billiton | 1,500 |
| Crystal | Offshore Oxnard, CA | Crystal Energy | 1,250 |
| Terminal GNL Mar Adentro | Offshore Baja CA, Mexico | ChevronTexaco | 750 |
| Energia Costa Azul LNG | Onshore Baja CA, Mexico | Sempra/Shell | 2,000 |
| Sound Energy Solutions | Onshore Long Beach, CA | Mitsubishi | 1,000 |
| Gulf Coast | | | |
| Compass Port | Offshore Alabama | ConocoPhillips | 1,000 |
| Energy Bridge | Offshore Louisiana | Excelerate | 500 |
| Gulf Landing | Offshore Louisiana | Shell | 1,000 |
| Main Pass Energy Hub | Offshore Louisiana | McMoran | 1,000 |
| Port Pelican | Offshore Louisiana | ChevronTexaco | 1,600 |
| Altamira | Onshore Altamira, Mexico | Shell/Total | 650 |
| Cameron LNG | Onshore Hackberry, LA | Sempra Energy | 1,500 |
| Corpus Christi LNG | Onshore Corpus Christi, TX | Cheniere/BPU | 2,600 |
| Freeport LNG | Onshore Freeport, TX | Freeport/Cheniere/Contango | 1,500 |
| Golden Pass | Onshore Sabine Pass, TX | ExxonMobil | 1,000 |
| Ingleside Energy Center | Onshore Ingleside, TX | Occidental Petroleum | 1,000 |
| Port Arthur | Onshore Port Arthur, TX | Sempra Energy | 1,500 |
| Sabine Pass | Onshore Sabine Pass, LA | Cheniere | 2,600 |
| Vista del Sol | Onshore Quintana Isl, TX | ExxonMobil | 1,000 |
| Bahamas/Florida | | | |
| Calypso | Onshore Freeport, Grand Bahama | Tractebel Bahamas LNG | 832 |
| Ocean Express | Onshore Ocean Cay, Bahamas | AES | 842 |
| High Rock LNG/Seafarer | Onshore Grand Bahama | El Paso | 820 |
| East Coast | | | |
| Bear Head | Onshore Nova Scotia, Canada | Access NW Energy | 1,000 |
| Canaport | Onshore New Brunswick, Canada | Irving Oil | 500 |
| Crown Landing | Onshore Logan Twshp, NJ | BP | 1,200 |
| KeySpan LNG | Onshore Providence, RI | KeySpan/BG Group | 525 |
| Weavers Cove | Onshore Fall River, MA | Poten | 800 |
| **Total** | | | **31,469** |

Yet opposition to new onshore facilities based on security and environmental concerns has arisen, particularly in market areas like the Northeast and Southern California. Even with the avoided costs of long-line transportation and the likelihood that a new market area source of natural gas would have a stabilizing impact on consumer prices, and even with proposals in areas with a rich history of maritime commerce, proposed onshore terminals have been defeated by local opposition – most notably and recently in Maine.

The path or strategy required to win approval for an import facility may be as simple as locating it where there is less local opposition. For example, in the Gulf Coast where the general public is well aware of the necessity for, and benefit of, large scale energy projects. Obviously, gas placed in the grid eventually finds its way to customers throughout the U.S. by direct transportation or displacement no matter where it initially enters.

**Increased LNG imports can expand available natural gas supply and help moderate prices.** Some analysts argue that although LNG can be landed in the U.S. at costs well below those seen in the market today (see exhibit XI-4), the price of LNG will be bid up to the prevailing market level set primarily by domestic gas and Canadian imports. Others suggest that the price of these traditional sources will be pulled down to the LNG price level.

## Exhibit XI-4

**Delivered Cost of LNG in the U.S. ($ per MMBtu)**

**Energy and Environmental Analysis (EEA)**

| | Everett | Cove Point | Elba Island | Lake Charles |
|---|---|---|---|---|
| *Middle East Production Costs, including processing and transport to liquefaction facilities* | 0.65 | 0.65 | 0.65 | 0.65 |
| *Liquefaction* | 1.09 | 1.09 | 1.09 | 1.09 |
| *Representative LNG Shipping Rates* | | | | |
| *Algeria* | 0.52 | 0.57 | 0.60 | 0.72 |
| *Nigeria* | 0.80 | 0.83 | 0.84 | 0.93 |
| *Norway* | 0.56 | 0.61 | 0.64 | 0.77 |
| *Venezuela* | 0.34 | 0.33 | 0.30 | 0.35 |
| *Trinidad and Tobago* | 0.35 | 0.35 | 0.32 | 0.38 |
| *Qatar* | 1.37 | 1.43 | 1.46 | 1.58 |
| *Australia* | 1.76 | 1.82 | 1.84 | 1.84 |
| *Regasification Cost* | 0.30 | 0.30 | 0.30 | 0.30 |
| *Total Cost of Middle East LNG* | 3.41 | 3.47 | 3.50 | 3.62 |

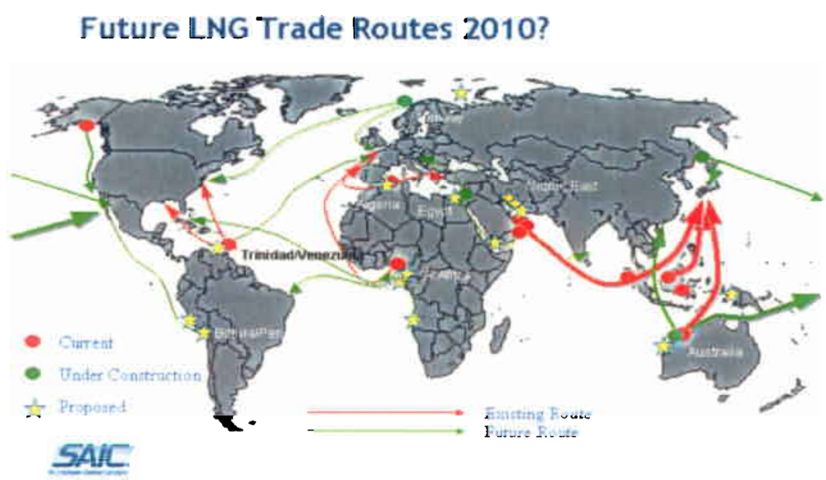
*All imported LNG is likely to be competitive at a delivered cost of about $3.50 per MMBtu.*

*Sources: DOE Technical Report Nine, Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector*, published in January 1993, *James Jensen, LNG Shipping Solutions, U.S. Energy Information Administration, The Global Liquefied Natural Gas Market: Status and Outlook*, December 2003.

It is the view of this report that given the construction of a sufficient number of receiving terminals, LNG facilities will operate at a high load factor and tend to push some higher cost domestic sources of gas out of the market. The worldwide gas resource is vast and diversely distributed. Roughly 93 percent of the world's gas reserves is located outside of North America. Further, based on existing infrastructure and gas demand, the U.S. is the most logical market for the bulk of the developing LNG supply worldwide for the foreseeable future. This view, however, does not preclude the knowledge that worldwide natural gas markets are expanding (for example, China) and that other countries are likely to increasingly compete with U.S. markets for LNG.

This report projects that increased LNG capability will lead to higher consumption levels and lower prices than otherwise would be the case. If LNG import capabilities are not significantly expanded, natural gas demand will be satisfied via higher cost domestic and Canadian sources.

**Exhibit XI-5**




Sources: British Gas and British Petroleum.

# XII. ALASKAN NATURAL GAS REPRESENTS A CRITICAL UNCERTAINTY

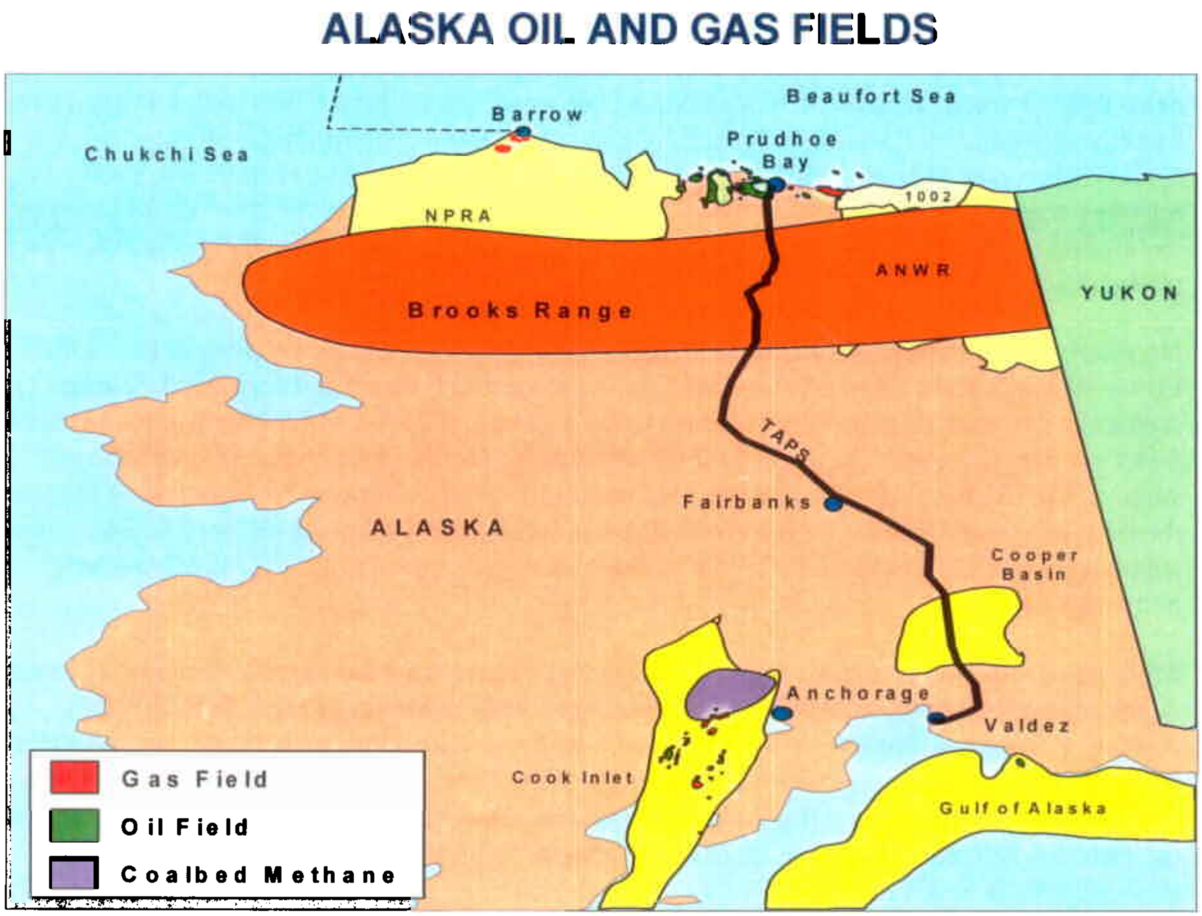
**Achieving a 30 quad natural gas market is unlikely without a significantly expanded supply contribution from Alaska.** To reach 30 quads of annual natural gas consumption in the United States will require new sources of gas for consumers. Alaska is poised to be one of those new sources. However, it is very difficult to predict the political process or economic supports that may be necessary to realize this potential. That said, if the political process, economic hurdles and logistical challenge of actually manufacturing the pipe are overcome, the gas is available and ready to flow.

No supply case in this report assumes the delivery of new incremental supplies of gas to the Lower-48 states from Alaska before 2014. In the Expected Policies and Expanded Policies scenarios, gas from Alaska delivers about 4 Bcf per day into Lower-48 markets, growing to over 6 Bcf per day (2.2 quads per year) by 2020, accounting for about 9 percent of total U.S. gas supply. The Existing Policies scenario does not allow for permitting or construction of the line through 2020 and therefore no incremental gas is supplied to the Lower-48 from Alaska. This supply constraint is one reason why the overall gas market grows to only 27 quads annually under this case.

**Most gas produced in Alaska today is reinjected rather than consumed.** Gas production in Alaska dates back more than 50 years, beginning in 1949 at the Barrow gas field in North Alaska. Production, however, did not exceed 1 Bcf/year until 1961, after production began in the Cook Inlet area. Production did not average more than 1 Bcfd until 1977, when commercial oil production from Prudhoe Bay began. Additional areas for future gas production may include the National Petroleum Reserve, the Arctic National Wildlife Refuge (ANWR) and coalbed methane area in South Alaska.

At the wellhead, Alaska is the third largest gas producing state in the United States, exceeded only by Louisiana and Texas. Since 1995 wellhead gas production has averaged over 9 Bcfd in Alaska. However, more than 80 percent of this production is re-injected due to the lack of the necessary infrastructure to move the gas to the Lower-48 and also to promote oil production. As a result, on a marketed basis, Alaska is only the eighth largest producing state. Marketed gas production in Alaska has averaged about 1.2 Bcfd (430 Bcf annually) since 1995. More than half of this marketed gas production is used as lease and plant fuel, and more than a quarter is used for LNG or ammonia manufacture for export. Less than 20 percent is used for "domestic" energy consumption in Alaska, and this market has shown almost no growth in the last 15 years.

## Exhibit XII-1




Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Non-Traditional Gas Sources*.

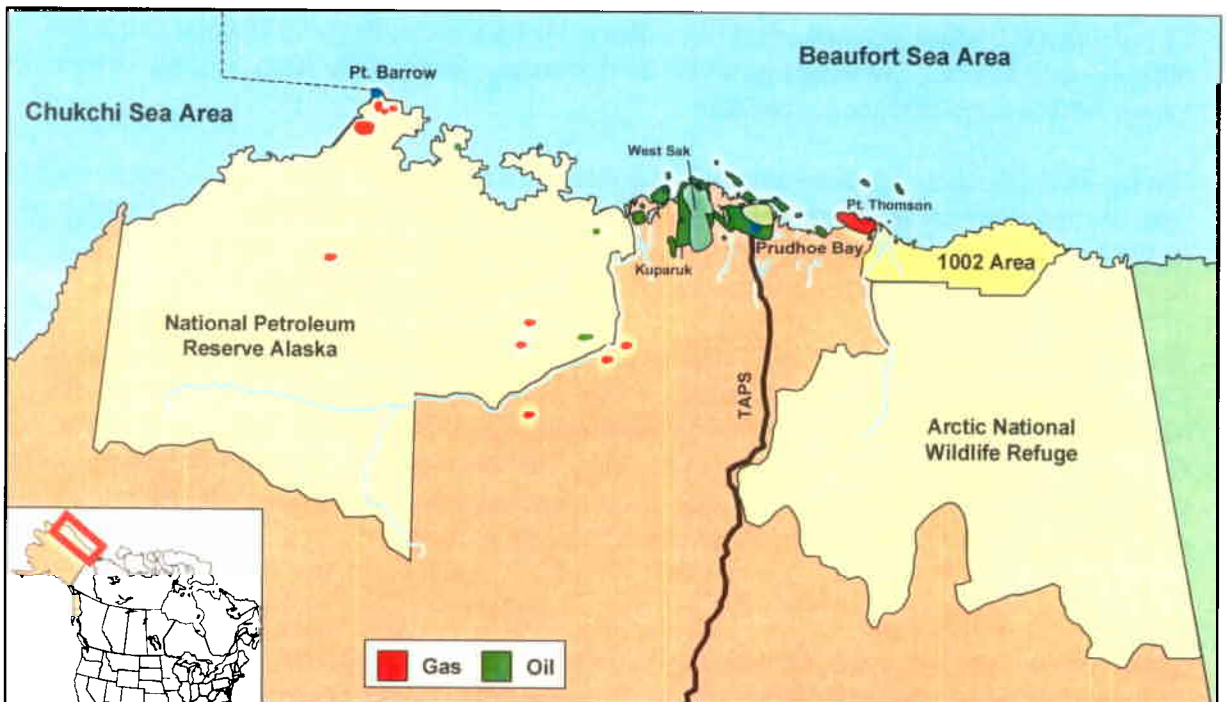
**Alaskan gas production and markets are at a transition point**. In the Cook Inlet area new supplies will be needed in the near-term to meet gas demand. The critical issue for the Cook Inlet markets is whether these new supplies will be obtained from new discoveries in South Alaska or by delivering gas from North Alaska. On the North Slope, the relative economics of gas production for delivery to a market is becoming more attractive relative to continued re-injection.

Unlike Cook Inlet, North Alaska gas production increased between 1980 and 2002, although most of that growth occurred by 1995. North Alaska gas production has grown slightly since 1995 but oil production has declined almost one third. Currently, almost two thirds of the Btu content of North Slope hydrocarbon production is in the gas stream, compared to only 50 percent in 1995 and 29 percent in 1988, when North Slope oil production peaked. In Prudhoe Bay, the gas share of the hydrocarbon stream is larger, currently accounting for about three fourths of the Btu content. The Prudhoe Bay reservoir is at an operational point where marketing of the produced gas may be very attractive to the owners if it is economically possible to deliver that gas to a market.

**North Slope natural gas reserves are only the *tip of the iceberg* when examining the total natural gas resource potential in Alaska.** When a pipeline connecting Alaskan gas to the Lower-48 states is mentioned, most often the 40 Tcf of known reserves associated with North Slope oil production is cited as the foundation for the pipeline supply. The fact is that those reserves are only a small portion of total Alaskan gas potential. The Potential Gas Committee estimates a resource potential of 251 Tcf in Alaska, including gas from coal seams and offshore. However, much of that resource potential is considered speculative because it has not yet been fully explored.

**Exhibit XII-2**

**NORTH ALASKA DISCOVERIES AND PROSPECTIVE AREAS**




Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Non-Traditional Gas Sources.*

Most of the press surrounding Alaska production issues centers on the Arctic National Wildlife Refuge (ANWR) and the National Petroleum Reserve Alaska (NPRA), outlined on the map above. However, there are large tracts of lands managed by the state of Alaska, as well as native lands that offer significant gas production potential and that are not hostage to the national debate on the environmental impacts of petroleum drilling. These properties are proximal to the proposed pipeline route and are far more likely to be gas-prone than oil-prone based on the geologic thermal history of the sediments in place. What they need for development is the transportation infrastructure that a gas pipeline would offer.

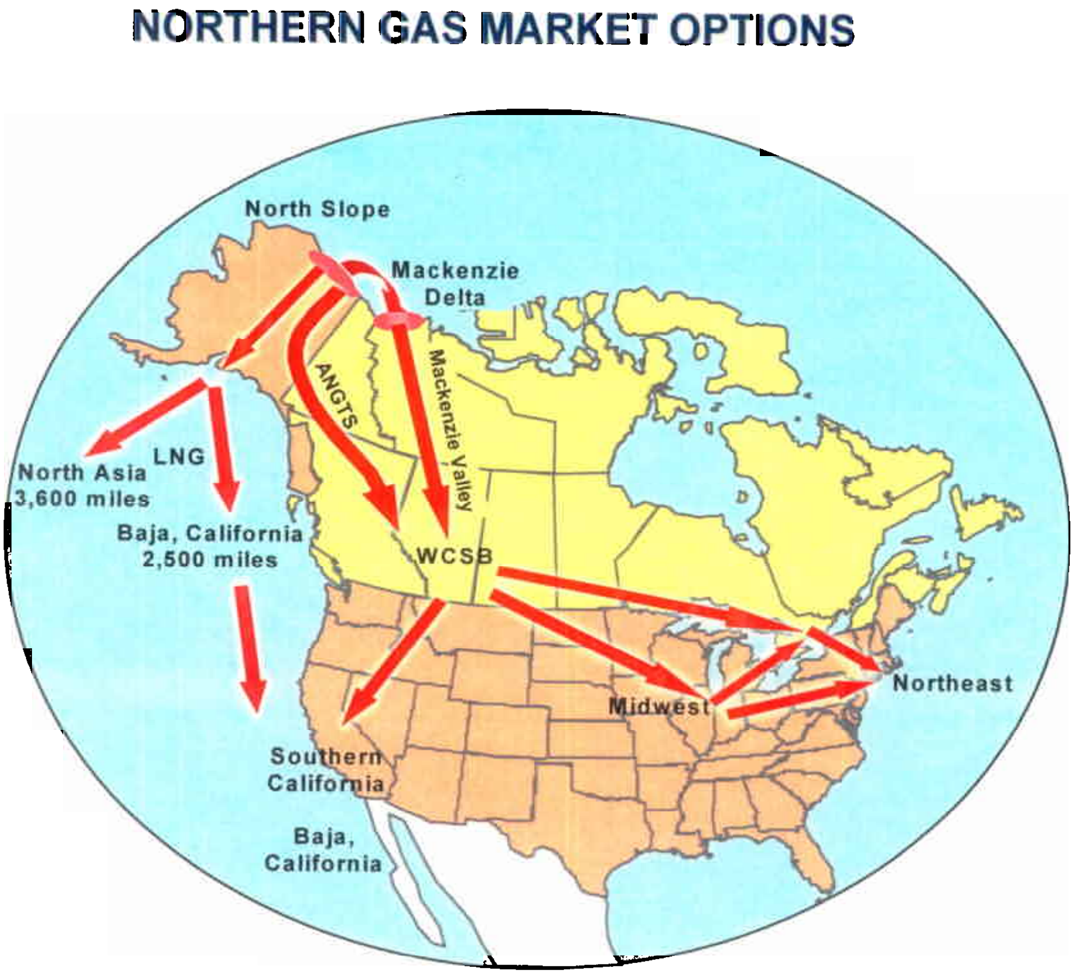
**Constructing a transportation system to move Alaskan gas to the Lower-48 is likely a $20 billion proposition.** The fundamental issues that impede all of the options described below to transport Alaskan gas to the Lower-48 states are quite simple – time and money. For example, the pipeline options entail roughly 10 years to construct with a price tag of some $20 billion. Combining that much time and money in an uncertain gas market, including the unknown potential market impacts of a burgeoning LNG trade, present great risk to project sponsors. It is unlikely that any project will move forward without the enactment of some measures to reduce that risk. That is, there must be no question that, once constructed, the pipeline will operate competitively at full load, 365 days per year.

The figure below shows the market options for North Alaska gas relative to its nearest large markets in North America and North Asia. From the North Slope to Southern California via the Alaskan Natural Gas Transportation System (ANGTS) route, gas would move 3,600 miles. The distance to the Midwest market is about the same as Southern California, and continuing gas movement to the Northeast would add 900 miles or more. If LNG were ever developed to move North Slope gas to Southern California, gas would move about 3,400 miles, 900 miles would be by pipeline (800 miles in Alaska and 100 miles from Baja to Southern California) and 2,500 miles by ship as LNG. No matter how you do it, moving gas from the Alaska North Slope to the Lower-48 is a long-distance proposition.

Having said that, there are three principal pipeline options to move North Alaska gas to market. Two are gas pipelines to connect North Alaska gas to the North American gas transmission grid in Western Canada. A third is a gas pipeline to South Alaska, where the gas would be liquefied for transport by ship to Pacific gas markets in North America or North Asia.

The two pipeline options that would deliver gas to Western Canada are the Alaska Highway Corridor and the "Over the Top" Corridor, which would move gas from North Alaska to the Mackenzie Delta via an offshore pipeline and then down the Mackenzie Valley to Western Canada. For delivery of Northern gas to Pacific Coast gas markets, the nominal delivery point would be the Foothills Pre-Build pipeline at Caroline, Alberta. Deliveries to the Midwest may entail linkage to the Foothills Pre-Build and Alliance pipelines.

**Exhibit XII-3**




Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Non-Traditional Gas Sources.*

The Alaska Highway corridor is the site of the proposed ANGTS project that was proposed in the late 1970s. A pipeline in the Alaska Highway corridor will run about 2,000 miles from the North Slope of Alaska producing areas to the high-volume North American gas transmission network in Alberta. To keep gas transportation charges competitive for this option, volumes for proposed projects have been about 4 Bcfd, with some discussion of volumes approaching 6 Bcfd.

The over-the-top option that would move gas from Prudhoe Bay to the Mackenzie Delta is shorter than the Alaskan Highway route, but it would be an unlikely winner in the pipeline construction derby primarily due to environmental opposition, opposition by the state of Alaska and the fact that the produced and transported gas would then miss the Alaska population centers along the interior pipeline route.

The shortest route, of course, would be to move gas to the south of Alaska near Valdez and then make it available for transport via LNG. At least insofar as the Lower-48 states are concerned this may be a non-starter simply because it is difficult to conceive of a LNG receiving terminal being built on the U.S. west coast due to citizen opposition. Even LNG projects in Mexico that could supply gas to the U.S. have met resistance.

## XIII. NATURAL GAS TRADE WITH MEXICO WILL HAVE A LIMITED OVERALL IMPACT ON THE U.S. MARKET

**Mexico is expected to remain a net importer of natural gas from the U.S, although the import levels are likely to decline.** Natural gas production in Mexico is about 1.8 Tcf annually from a resource base that likely exceeds 120 Tcf. More specifically, proved reserves are estimated by PEMEX to be 28.1 Tcf. In terms of gas-driven exploration activity, the country is lightly explored.

Under all scenarios examined in this report, natural gas trade between the United States and Mexico remains a net negative to the U.S. supply balance throughout the period 2005-2020. Net exports of natural gas from the U.S. to Mexico are projected to increase from 340 Tbtu in 2003 to 526 TBtu in 2005, decreasing to a net of 176 TBtu by 2020. There are numerous reasons why Mexico is not expected to be a net supplier of gas to the U.S., including the lack of sufficient transportation infrastructure, but perhaps even more important, there is a growing demand for gas in Mexico.

**Primary energy consumption and natural gas consumption in Mexico are growing.** Primary energy consumption in Mexico grew 23 percent between 1991 and 2000. Most of that growth occurred after 1995, when the Mexican economy came out of its early 1990s doldrums. Gas consumption, specifically, grew more rapidly during the 1990s than total primary energy consumption. As a result, the gas share of Mexico's primary energy consumption grew from 21 percent in 1991 to almost 24 percent in 2000. Most of the increased share occurred after 1995.

Additionally, electricity consumption in Mexico grew more than twice as fast as growth in primary energy consumption during the 1990s. Although most Mexican electricity is generated by oil, most proposed new electricity generation capacity is gas-fired and a significant amount of existing oil-fired generation capacity may be converted to gas. As a result, the demand for gas in Mexico should surge as new gas-fired generation comes on line. The American Gas Foundation report, *Meeting the Gas Supply Challenge of the Next 20 Years – Non Traditional Gas Sources (December 2002),* estimates that natural gas consumed for electricity generation could grow from less than 30 percent of the country's gas consumption to as much as 59 percent by 2020. Similar to the situation in the U.S., it is likely that growing gas demand for electricity generation in Mexico may result in higher gas consumption for this sector than for all industrial uses by 2020.

Mexico's gas supply outlook is not as robust as the demand outlook. Between 1995 and 2001 Mexican gas consumption increased about 300 Bcf, and one fourth of the increased Mexican gas supply came from the United States. In 2001, 10 percent of Mexican gas came from the United States.

**Pipeline imports from the U.S. and/or LNG from other sources will play a growing role in Mexican gas supply.** While all gas imports currently come from the United States, LNG is likely to become a significant factor in Mexican gas imports. In fact, in the most bullish of scenarios LNG could replace all U.S. gas supply in the Mexican market. Until significant LNG imports begin, the United States will supply any increased demand for gas imports by Mexico.

In summary, because of a need to supply growing electricity demand in Mexico, Mexican gas demand is likely to grow. Unless a world-scale gas field, play, or basin beyond current expectations is discovered in Mexico, this rapid growth in Mexican gas demand will need growing gas deliveries from outside Mexico.

In the near term, the increased demand for imports likely will be met by increased deliveries from U.S. gas supply sources. By 2005, U.S. gas exports to Mexico are likely to exceed 1.4 Bcfd. If U.S. gas supplies remain tight in the near-term, this increased gas demand from Mexico would contribute to upward pressures on gas prices.

Should LNG terminals be developed in Mexico after 2005, Mexican demand for U.S. gas supply may begin to decline. The pace at which U.S. gas exports to Mexico tail off after 2010 will depend on the number and timing of additional LNG terminals in Mexico.

# XIV. DRAMATIC MOVEMENT IS NOT ANTICIPATED FOR ANNUAL NATURAL GAS PRICES – UPWARD OR DOWNWARD

**Average annual natural gas prices are projected to remain in the $5 to $6 range throughout most of the forecast period.** Natural gas prices moved dramatically higher relative to historic normal levels late in the year 2000. Record cold temperatures late in 2000 pushed demand – and prices – upward, with an annual average price of $4.29 per MMBtu set at the Henry Hub. In contrast, prices for most of the 1990s were in the low $2.00 per MMBtu range. Prices averaged $4.00 per MMBtu in 2001, fell back to $3.37 per MMBtu in 2002, but rebounded to $5.49 per MMBtu in 2003. The average price in 2004 is expected to be in the mid $5.00 per MMBtu range. In addition to markedly higher price levels experienced since 2000, gas markets have exhibited far more short-term volatility than in past years. Spikes of $7 to $10 per MMBtu have been experienced in three of the past four years. In a study prepared for the American Gas Foundation,[1] natural gas prices were found to be more volatile than were the prices of all other commodities analyzed, with the exception of electricity.

Gas prices projected under the Expected Policies scenario average $6.72 per MMBtu throughout the forecast period. The average for the five-year period 2001-2005 is $5.26 per MMBtu, jumping to an average of $6.72 per MMBtu for 2006-2010. Supply-side relief, primarily in the form of LNG, produces a reduction to $6.31 per MMBtu in the 2011 to 2015 period. Market pressures push prices upward to $7.14 per MMBtu in the final five-year period of the forecast, peaking at $8.15 per MMBtu in 2020.

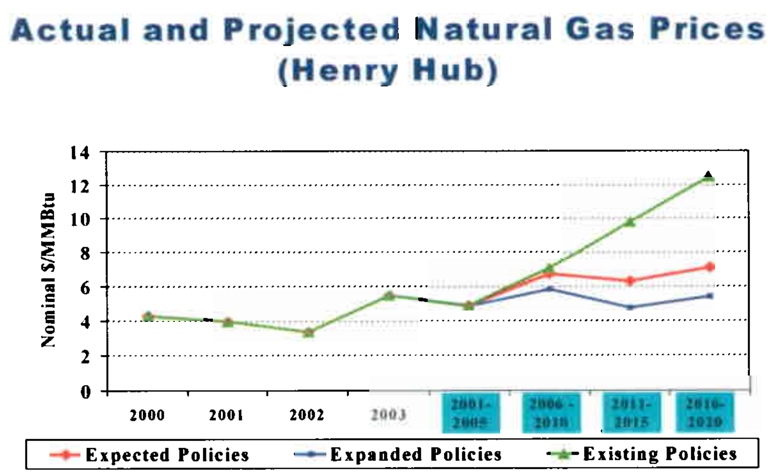
Prices projected under the Expanded Policies scenario move in a pattern similar to, but lower than, those projected in the Expected Policies scenario. Prices under this scenario average $5.86 per MMBtu for 2006-2010, $4.77 per MMBtu for 20011-2015, and $5.41 per MMBtu for 2016-2020. The peak of $5.47 in 2020 is 33 percent less than the Expected Policies final year price.

Prices in the Existing Policies scenario move upward earlier and far more sharply than in either of the other scenarios. The five-year average prices under this scenario are $7.08, $9.81 and $12.50 per MMBtu, with a peak of $13.76 per MMBtu in 2020. The peak price under this scenario is nearly 70 percent higher than the Expected Policies peak. The failure to construct new LNG receiving terminals pushes prices sharply upward as early as 2008 under this scenario.

**Natural gas prices, when adjusted for inflation, are projected to decline modestly.** As stated above, projected gas prices remain in a $5-$6 range for most of the 17-year forecast. Recognizing that this level is two to three times higher than the prevailing level of the 1990s, the projected prices actually fall when adjusted for inflation ("real" prices, stated in 2003 dollars). The Expected Policies real price in 2020 is $5.35 per MMBtu, 3 percent below the price of $5.49 per MMBtu set in 2003. The 2020 real price under the Expanded Policies scenario is $3.59 per MMBtu – a 35 percent decline-while the Existing Policies real price of $9.03 per MMBtu in 2020 is 64 percent higher than the actual 2003 price.

**Projected prices in the Expanded Policies scenario are 33 percent lower than those of the Expected Policies scenario, but they are 70 percent higher in the Existing Policies scenario.** The price trajectory of the Expected Policies scenario is not the midpoint of the two alternative scenarios. It is much closer to the Expanded Policies scenario than it is to the Existing Policies scenario. Clearly, the actions of the Expanded Policies scenario can help to ease upward pressure on gas prices. However, the implication of the alternative scenario analysis is that a lack of action, as assumed in the Existing Policies scenario, will have a more dramatic impact on gas prices than will the positive actions of the Expanded Policies scenario– but in an upward direction.

**Exhibit XIV-1**




Forecasted prices are in 5 year averages.

**Although price fluctuations are not expected to be extreme on an annual basis, short-term price volatility likely will persist.** The nature of supply and demand in the natural gas market makes it vulnerable to price volatility. The demand for natural gas is capable of severe fluctuations over very short time intervals. Residential and commercial demand are largely determined by the weather, which drives the need for heating. Electricity generation gas demand is also driven by weather – hot weather in the summer that increases the need for air conditioning, and, to a lesser extent, cold weather in the winter that increases the need for electric heating. Industrial gas demand is driven by the level of economic activity, which can also fluctuate over short time intervals, although certainly not to the same extent as weather. Conversely, the supply side of the gas market is largely fixed in the short run. Wells and pipelines cannot be added and subtracted quickly as the temperature or GDP move up and down. The relatively fixed nature of supply coupled with extremely variable demand is conducive to price volatility. Demand moving quickly upward with a relatively fixed supply can push prices sharply upward, while an evaporation of demand with that same fixed supply pushes prices sharply downward.

The natural gas market was not as susceptible to price volatility in the 1980s and 1990s as it is today because the system was, in essence, overbuilt. There was surplus production and delivery capability on a national basis and changes in demand could usually be accommodated without placing undue strain on the system. Therefore the price response was limited. That surplus capability on the supply side has been eliminated. Since late 2000, spikes in demand have generally resulted in spikes in prices. It is unlikely that this situation will change in the near future. Investments will not be made in drilling rigs, pipelines and storage fields if these assets are not to be fully utilized. Utility regulators and investors will not allow it. Because the system is unlikely to be "overbuilt" in a physical sense, a reduction in price volatility may depend on other mechanisms, such as financial hedging and the use of long-term fixed price contracts.

**Failure to complete large-scale supply projects would have a severe impact on natural gas consumers.** The model employed for this study foresees a tight and tenuous natural gas market. Demand, driven primarily by electricity generation customers, continues to move upward. Supply can meet that demand, but it is pressed to do so and a return to pre-2000 price levels is not deemed plausible. The completion of large-scale supply projects, notably LNG receiving terminals and the Alaskan gas pipeline, as well as increased access for Lower-48 production, can take some of the pressure off domestic production in traditional areas. However, a failure to move forward with these options quickly would have severe consequences. As illustrated by the Existing Policies scenario, natural gas prices will move to levels never before experienced if new sources of supply are not introduced into the mix. Actions must be taken today to avoid these consequences in the very near future.

[1] American Gas Foundation for Oak Ridge National Laboratories, *Natural Gas and Energy Price Volatility*, October 2003.

# APPENDIX I

# EXPECTED POLICIES SCENARIO

# Expected Policies Scenario

## Regional Natural Gas Consumption (Bcf)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | 1999-2010 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **United States** | | | | | | | | | | | | | | | | |
| Total Consumption | 21,990 | 21,363 | 22,359 | 23,270 | 21,548 | 22,419 | 21,497 | 21,996 | 22,079 | 21,947 | 22,453 | 23,154 | 23,632 | 24,247 | 1888 | 0.74% |
| Residential | 4,983 | 4,393 | 4,651 | 4,958 | 4,688 | 4,810 | 5,037 | 5,038 | 5,091 | 5,105 | 5,144 | 5,233 | 5,277 | 5,371 | 720 | 1.32% |
| Commercial | 3,222 | 2,928 | 3,070 | 3,240 | 3,067 | 3,123 | 3,191 | 3,153 | 3,170 | 3,140 | 3,151 | 3,204 | 3,240 | 3,325 | 255 | 0.73% |
| Industrial | 8,904 | 8,828 | 8,944 | 8,828 | 7,496 | 7.995 | 7.196 | 7;253 | 7;027 | 6,526 | 6,621 | 6,762 | 6,834 | 6,891 | -2052 | -2.34% |
| Cogeneration/1 | 1,481 | 1,474 | 1,492 | 1,471 | 1,179 | 1,249 | 1,116 | 1,124 | 1,091 | 993 | 1,000 | 1,021 | 1,028 | 1,034 | -459 | -3.28% |
| Power Generation | 2,963 | 3,340 | 3,766 | 4,288 | 4,315 | 4,543 | 4,107 | 4,597 | 4,856 | 5,229 | 5,565 | 5,957 | 6,278 | 6,619 | 2853 | 5.26% |
| Cogeneration/1 | 0 | 0 | 24 | 120 | 280 | 466 | 525 | 600 | 655 | 748 | 818 | 889 | 955 | 1,019 | 995 | 40.77% |
| Pipeline Fuel | 697 | 662 | 708 | 726 | 737 | 729 | 754 | 747 | 729 | 739 | 757 | 776 | 780 | 814 | 106 | 1.27% |
| Lease & Plant | 1,221 | 1,212 | 1,220 | 1,230 | 1,246 | 1,220 | 1,211 | 1,207 | 1,206 | 1,208 | 1,214 | 1,222 | 1,222 | 1,227 | 7 | 0.05% |
| Cogeneration Total | 1,481 | 1,474 | 1,516 | 1,591 | 1,459 | 1,714 | 1,641 | 1,725 | 1,746 | 1,742 | 1,818 | 1,909 | 1,983 | 2,053 | 537 | 2.79% |

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

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# Expected Policies Scenario

| | Regional Natural Gas Consumption (Bcf) | | | | | | | | | | 2010-2020 | | 1999-2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | Annual % Change | Change | Annual % Change |
| **United States** | | | | | | | | | | | | | | |
| Total Consumption | 24,812 | 25,469 | 26,088 | 26,761 | 27,859 | 28,008 | 28,522 | 28,987 | 29,325 | 29,572 | 5326 | 2.01% | 7213 | 1.34% |
| Residential | 5,463 | 5,566 | 5,607 | 5,678 | 5,749 | 5,863 | 5,898 | 5,977 | 6,054 | 6,142 | 771 | 1.35% | 1491 | 1.33% |
| Commercial | 3,405 | 3,472 | 3,503 | 3,548 | 3,592 | 3,669 | 3,687 | 3,739 | 3,785 | 3,829 | 504 | 1.42% | 759 | 1.06% |
| Industrial | 6,928 | 6,928 | 7,027 | 7,084 | 7,315 | 7,238 | 7,316 | 7,517 | 7,557 | [illegible] | 622 | [illegible] | -1430 | -0.83% |
| Cogeneration/1 | 1,040 | 1,042 | 1,055 | 1,064 | 1,098 | 1,093 | 1,097 | 1,130 | 1,133 | 1,129 | 95 | 0.88% | -364 | -1.32% |
| Power Generation | 6,999 | 7,463 | 7,899 | 8,371 | 9,069 | 9,106 | 9,473 | 9,577 | 9,747 | 9,906 | 3287 | 4.11% | 6141 | 4.71% |
| Cogeneration/1 | 1,092 | 1,185 | 1,276 | 1,368 | 1,502 | 1,527 | 1,595 | 1,617 | 1,656 | 1,694 | 675 | 5.22% | 1671 | 22.55% |
| Pipeline Fuel | 787 | 801 | 812 | 840 | 899 | 906 | 924 | 956 | 964 | 964 | 150 | 1.70% | 256 | 1.48% |
| Lease & Plant | 1,231 | 1,239 | 1,241 | 1,239 | 1,235 | 1,227 | 1,224 | 1,221 | 1,217 | 1,218 | -9 | -0.08% | -3 | -0.01% |
| Cogeneration Total | 2,132 | 2,227 | 2,331 | 2,433 | 2,600 | 2,619 | 2,692 | 2,747 | 2,789 | 2,823 | 770 | 3.24% | 1307 | 3.00% |

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.
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# Expected Policies Scenario

| U.S. Total | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2001-2010 Change | 2001-2010 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Regional Industrial Natural Gas Consumption (Bcf) | | | | | | | | | | | |
| **Total of All Industrial** | | | | | | | | | | | | |
| Total of All End Uses | 7,545 | 8,005 | 7,197 | 7,255 | 7,027 | 6,526 | 6,621 | 6,764 | 6,836 | 6,895 | -649 | -0.99% |
| Boilers | 2,479 | 2,573 | 2,424 | 2,501 | 2,462 | 2,430 | 2,506 | 2,558 | 2,601 | 2,632 | 153 | 0.67% |
| Process Heat | 2,635 | 2,825 | 2,528 | 2,558 | 2,473 | 2,188 | 2,194 | 2,249 | 2,262 | 2,274 | -361 | -1.62% |
| Other Uses | 1,752 | 1,850 | 1,661 | 1,672 | 1,629 | 1,478 | 1,488 | 1,519 | 1,530 | 1,540 | -211 | -1.42% |
| Cogen Gas Use /1 | 1,179 | 1,249 | 1,116 | 1,124 | 1,091 | 993 | 1,000 | 1,021 | 1,028 | 1,034 | -145 | -1.45% |
| Ammonia Feedstock | 370 | 426 | 319 | 280 | 235 | 212 | 211 | 211 | 211 | 211 | -159 | -6.07% |
| Methanol Feedstock | 157 | 173 | 102 | 78 | 56 | 41 | 39 | 39 | 39 | 39 | -118 | -14.38% |
| Hydrogen Feedstock | 152 | 157 | 162 | 167 | 172 | 177 | 182 | 188 | 193 | 199 | 47 | 3.05% |
| **Food** | | | | | | | | | | | | |
| Total of All End Uses | 599 | 623 | 586 | 585 | 581 | 538 | 542 | 552 | 557 | 564 | -36 | -0.68% |
| Boilers | 223 | 229 | 226 | 229 | 231 | 229 | 233 | 237 | 239 | 241 | 18 | 0.85% |
| Process Heat | 226 | 237 | 214 | 211 | 207 | 183 | 183 | 187 | 189 | 192 | -35 | -1.83% |
| Other Uses | 150 | 158 | 146 | 145 | 142 | 126 | 126 | 128 | 129 | 131 | -19 | -1.48% |
| **Paper** | | | | | | | | | | | | |
| Total of All End Uses | 590 | 595 | 595 | 602 | 604 | 5135 | 584 | 583 | 5713 | 574 | -16 | -0.31% |
| Boilers | 410 | 413 | 414 | 418 | 418 | 412 | 416 | 418 | 418 | 418 | 8 | 0.21% |
| Process Heat | 55 | 55 | 55 | 56 | 56 | 52 | 51 | 50 | 49 | 47 | -7 | -1.60% |
| Other Uses | 125 | 126 | 126 | 129 | 130 | 121 | 117 | 115 | 112 | 108 | -17 | -1.58% |
| **Petroleum Refining** | | | | | | | | | | | | |
| Total of All End Uses | 1,351 | 1,414 | 1,308 | 1,274 | 1,232 | 1,089 | 1,084 | 1,101 | 1,107 | 1,115 | -236 | -2.11% |
| Boilers | 354 | 358 | 357 | 362 | 363 | 361 | 365 | 368 | 369 | 371 | 16 | 0.50% |
| Process Heat | 797 | 846 | 759 | 727 | 691 | 579 | 572 | 583 | 587 | 592 | -206 | -3.26% |
| Other Uses | 199 | 211 | 192 | 185 | 178 | 150 | 148 | 151 | 152 | 153 | -47 | -2.92% |

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

**Regional Industrial Natural Gas Consumption (Bcf)**

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2001-2020 Change | Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total of All** | | | | | | | | | | | | |
| Total of All End Uses | 6,931 | 6,932 | 7,032 | 7,087 | 7,319 | 7,249 | 7,323 | 7,520 | 7,559 | 7,516 | -28 | -0.02% |
| Boilers | 2,649 | 2,654 | 2,700 | 2,713 | 2,804 | 2,752 | 2,818 | 2,855 | 2,883 | 2,867 | 389 | 0.77% |
| Process Heat | 2,282 | 2,276 | 2,305 | 2,329 | 2,410 | 2,394 | 2,394 | 2,489 | 2,491 | 2,466 | -169 | -0.35% |
| Other Uses | 1,549 | 1,551 | 1,572 | 1,587 | 1,641 | 1,638 | 1,641 | 1,698 | 1,701 | 1,693 | -59 | -0.18% |
| Cogen Gas Use /1 | 1,040 | 1,042 | 1,055 | 1,064 | 1,098 | 1,093 | 1,097 | 1,130 | 1,133 | 1,129 | -50 | -0.23% |
| Ammonia Feedstock | 208 | 206 | 206 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | -165 | -3.06% |
| Methanol Feedstock | 37 | 33 | 31 | 29 | 28 | 22 | 20 | 20 | 20 | 17 | -140 | -11.01% |
| Hydrogen Feedstock | 205 | 211 | 218 | 224 | 231 | 238 | 245 | 252 | 260 | 268 | 116 | 3.02% |
| **Food** | | | | | | | | | | | | |
| Total of All End Uses | 568 | 572 | 579 | 586 | 598 | 603 | 604 | 621 | 622 | 623 | 24 | 0.20% |
| Boilers | 242 | 244 | 246 | 248 | 251 | 252 | 255 | 258 | 260 | 262 | 39 | 0.84% |
| Process Heat | 193 | 195 | 197 | 200 | 206 | 208 | 207 | 216 | 215 | 215 | -12 | -0.27% |
| Other Uses | 132 | 133 | 135 | 137 | 141 | 142 | 142 | 146 | 146 | 147 | -4 | -0.13% |
| **Paper** | | | | | | | | | | | | |
| Total of All End Uses | 569 | 564 | 561 | 559 | 559 | 555 | 552 | 555 | 551 | 547 | -42 | -0.39% |
| Boilers | 418 | 417 | 418 | 418 | 420 | 418 | 420 | 421 | 421 | 420 | 10 | 0.13% |
| Process Heat | 46 | 44 | 43 | 43 | 42 | 41 | 40 | 41 | 39 | 38 | -16 | -1.83% |
| Other Uses | 106 | 103 | 100 | 98 | 97 | 96 | 92 | 93 | 91 | 89 | -36 | -1.77% |
| **Petroleum Refining** | | | | | | | | | | | | |
| Total of All End Uses | 1,120 | 1,124 | 1,131 | 1,141 | 1,155 | 1,161 | 1,158 | 1,184 | 1,183 | 1,183 | -168 | -0.70% |
| Boilers | 372 | 372 | 375 | 376 | 378 | 378 | 381 | 383 | 385 | 385 | 31 | 0.44% |
| Process Heat | 595 | 597 | 602 | 608 | 618 | 622 | 618 | 637 | 635 | 634 | -163 | -1.20% |
| Other Uses | 153 | 154 | 155 | 156 | 159 | 160 | 159 | 163 | 163 | 163 | -36 | -1.04% |

**1.** Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.
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# Expected Policies Scenario

## Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2001-2010 Change | 2001-2010 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Chemicals** | | | | | | | | | | | | |
| Total of All End Uses | 2,602 | 2,986 | 2,470 | 2,510 | 2,341 | 2,219 | 2,310 | 2,394 | 2,447 | 2,478 | -124 | -0.54% |
| Boilers | 822 | 910 | 781 | 828 | 780 | 763 | 815 | 848 | 879 | 899 | 77 | 1.00% |
| Process Heat | 549 | 676 | 568 | 605 | 571 | 528 | 551 | 579 | 588 | 592 | 43 | 0.84% |
| Other Uses | 551 | 643 | 538 | 552 | 528 | 498 | 513 | 530 | 536 | 538 | -13 | -0.26% |
| Ammonia Feedstock | 370 | 426 | 319 | 280 | 235 | 212 | 211 | 211 | 211 | 211 | -159 | -6.07% |
| Methanol Feedstock | 157 | 173 | 102 | 78 | 56 | 41 | 39 | 39 | 39 | 39 | -118 | -14.38% |
| Hydrogen Feedstock | 152 | 157 | 162 | 167 | 172 | 177 | 182 | 188 | 193 | 199 | 47 | 3.05% |
| **Stone, Clay and Glass** | | | | | | | | | | | | |
| Total of All End Uses | 349 | 369 | 340 | 344 | 344 | 309 | 311 | 321 | 327 | 335 | -14 | -0.46% |
| Boilers | 17 | 18 | 17 | 18 | 18 | 18 | 19 | 19 | 20 | 20 | 3 | 1.63% |
| Process Heat | 287 | 303 | 278 | 282 | 281 | 251 | 252 | 261 | 266 | 272 | -15 | -0.61% |
| Other Uses | 44 | 47 | 44 | 44 | 45 | 40 | 40 | 41 | 42 | 43 | -1 | -0.32% |
| **Iron and Steel** | | | | | | | | | | | | |
| Total of All End Uses | 318 | 334 | 338 | 368 | 368 | 338 | 329 | 325 | 316 | 309 | -9 | -0.30% |
| Boilers | 50 | 53 | 56 | 60 | 60 | 59 | 60 | 61 | 61 | 61 | 11 | 2.23% |
| Process Heat | 237 | 248 | 248 | 272 | 271 | 245 | 237 | 233 | 225 | 219 | -18 | -0.88% |
| Other Uses | 31 | 33 | 34 | 36 | 37 | 33 | 32 | 31 | 30 | 30 | -1 | -0.52% |
| **Primary Aluminum** | | | | | | | | | | | | |
| Total of All End Uses | 89 | 85 | 82 | 82 | 80 | 71 | 69 | 70 | 68 | 66 | -23 | -3.23% |
| Boilers | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 0 | 0.23% |
| Process Heat | 73 | 70 | 67 | 66 | 65 | 56 | 54 | 55 | 54 | 52 | -22 | -3.79% |
| Other Uses | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | -1 | -3.60% |
| **Other Primary Metals** | | | | | | | | | | | | |
| Total of All End Uses | 191 | 169 | 137 | 137 | 134 | 117 | 116 | 117 | 118 | 119 | -73 | -5.18% |
| Boilers | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -1 | -2.45% |
| Process Heat | 105 | 93 | 74 | 74 | 72 | 62 | 62 | 63 | 63 | 64 | -42 | -5.44% |
| Other Uses | 81 | 72 | 59 | 58 | 57 | 50 | 50 | 50 | 50 | 51 | -30 | -5.05% |

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# Expected Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2001-2020 Change | 2001-2020 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Chemicals** | | | | | | | | | | | | |
| Total of All End Uses | 2,493 | 2,480 | 2,543 | 2,552 | 2,707 | 2,603 | 2,683 | 2,749 | 2,779 | 2,731 | 130 | 0.26% |
| Boilers | 907 | 903 | 934 | 933 | 1,005 | 949 | 993 | 1,011 | 1,024 | 998 | 176 | 1.03% |
| Process Heat | 595 | 589 | 606 | 609 | 657 | 625 | 645 | 668 | 675 | 658 | 109 | 0.96% |
| Other Uses | 541 | 538 | 549 | 552 | 582 | 565 | 575 | 592 | 595 | 585 | 34 | 0.32% |
| Ammonia Feedstock | 208 | 206 | 206 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | -165 | -3.06% |
| Methanol Feedstock | 37 | 33 | 31 | 29 | 28 | 22 | 20 | 20 | 20 | 17 | -140 | -11.01% |
| Hydrogen Feedstock | 205 | 211 | 218 | 224 | 231 | 238 | 245 | 252 | 260 | 268 | 116 | 3.02% |
| **Stone, Clay and Glass** | | | | | | | | | | | | |
| Total of All End Uses | 340 | 345 | 352 | 361 | 373 | 380 | 380 | 399 | 402 | 405 | 56 | 0.79% |
| Boilers | 20 | 20 | 21 | 21 | 22 | 22 | 22 | 23 | 23 | 23 | 6 | 1.66% |
| Process Heat | 276 | 280 | 286 | 293 | 303 | 309 | 309 | 325 | 327 | 329 | 42 | 0.72% |
| Other Uses | 44 | 45 | 45 | 47 | 48 | 49 | 49 | 52 | 52 | 53 | 8 | 0.89% |
| **Iron and Steel** | | | | | | | | | | | | |
| Total of All End Uses | 305 | 299 | 296 | 295 | 295 | 295 | 284 | 295 | 291 | 284 | -34 | -0.59% |
| Boilers | 61 | 61 | 61 | 61 | 62 | 61 | 62 | 62 | 62 | 62 | 12 | 1.14% |
| Process Heat | 215 | 209 | 207 | 206 | 206 | 206 | 196 | 205 | 202 | 195 | -42 | -1.01% |
| Other Uses | 29 | 28 | 28 | 28 | 28 | 28 | 27 | 28 | 27 | 27 | -4 | -0.80% |
| **Primary Aluminum** | | | | | | | | | | | | |
| Total of All End Uses | 64 | 61 | 58 | 57 | 56 | 55 | 51 | 53 | 52 | 50 | -40 | -3.03% |
| Boilers | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 10 | 0 | -0.08% |
| Process Heat | 49 | 46 | 44 | 43 | 42 | 41 | 38 | 40 | 39 | 37 | -37 | -3.59% |
| **Other Uses** | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | -3 | -3.49% |
| Other Primary Metals | | | | | | | | | | | | |
| Total of All End Uses | 119 | 119 | 120 | 121 | 123 | 124 | 122 | 126 | 125 | 124 | -67 | -2.24% |
| Boilers | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -1 | -1.08% |
| Process Heat | 64 | 64 | 64 | 65 | 66 | 66 | 66 | 68 | 67 | 67 | -38 | -2.36% |
| Other Uses | 51 | 51 | 51 | 52 | 53 | 53 | 52 | 54 | 53 | 53 | -28 | -2.18% |

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# Expected Policies Scenario

| | | | Regional | Industrial Natural | | | Gas Consumption | | | (Bcf) | 2001-2010 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **U.S. Total** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **Change** | **Annual %Change** |
| **Other Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 869 | 837 | 770 | 765 | 759 | 708 | 714 | 727 | 735 | 746 | -123 | -1.68% |
| Boilers | 358 | 348 | 334 | 340 | 342 | 340 | 346 | 351 | 355 | 359 | 1 | 0.03% |
| Process Heat | 209 | 198 | 174 | 172 | 168 | 148 | 148 | 151 | 153 | 156 | -53 | -3.18% |
| Other Uses | 303 | 290 | 261 | 253 | 249 | 220 | 220 | 225 | 228 | 232 | -71 | -2.93% |
| **Non-Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 587 | 592 | 571 | 588 | 584 | 553 | 561 | 573 | 581 | 590 | 3 | 0.06% |
| Boilers | 228 | 229 | 224 | 231 | 234 | 233 | 238 | 242 | 246 | 249 | 21 | 0.97% |
| Process Heat | 96 | 98 | 92 | 93 | 91 | 84 | 84 | 87 | 88 | 90 | -7 | -0.80% |
| Other Uses | 262 | 265 | 255 | 265 | 260 | 237 | 239 | 243 | 247 | 251 | -11 | -0.46% |
| **Industrial Curtailments** | **49** | **10** | **1** | **2** | **0** | **0** | **1** | **2** | **1** | **4** | **-45** | **-24.40%** |

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# Expected Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | tool-2020 Change | Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other** | | | | | | | | | | | | |
| Total of All End **Uses** | 755 | 764 | 777 | 791 | 813 | **826** | **836** | **865** | **876** | 888 | 19 | 0.11% |
| Boilers | 362 | 367 | 372 | 378 | 386 | 390 | 398 | 406 | 414 | 420 | 62 | 0.85% |
| Process Heat | 158 | 160 | 163 | 166 | 172 | 175 | 176 | 185 | 186 | 188 | -20 | -0.54% |
| Other Uses | 235 | 237 | 241 | 247 | 255 | 260 | 261 | 273 | 276 | 280 | -23 | -0.42% |
| **Non-** | | | | | | | | | | | | |
| Total of All End Uses | 598 | 605 | 615 | 626 | 640 | 648 | 652 | 673 | 677 | 681 | 94 | 0.79% |
| Boilers | 252 | 255 | 258 | 261 | 265 | 267 | 272 | 276 | 279 | 282 | 54 | 1.12% |
| Process Heat | 91 | 92 | 94 | 96 | 98 | 99 | 100 | 104 | 104 | 105 | 8 | 0.43% |
| Other Uses | 255 | 258 | 263 | 269 | 277 | 281 | 281 | 294 | 294 | 295 | 33 | 0.62% |
| **Industrial Curtailments** | **3** | **4** | **5** | **3** | **4** | **11** | **7** | **3** | **2** | **3** | **-45** | **-12.83%** |

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# Expected Policies Scenario

Power Generation Capacity (GW)

| LOWER-48 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TOTAL CAPACITY | 723.2 | 727.4 | 736.0 | 763.8 | 799.9 | 865.0 | 920.8 | 927.8 | 935.7 | 951.5 | 956.5 | 961.6 | 965.9 | 972.0 | 236.0 | 2.56% |
| OIL/GAS CAPACITY | 215.1 | 218.9 | 229.1 | 256.4 | 291.4 | 352.6 | 405.0 | 408.8 | 413.5 | 426.0 | 427.9 | 429.8 | 431.7 | 433.6 | 204.5 | 5.97% |
| *CT/CC ADDITIONS* | *0.0* | 2.1 | 10.5 | 35.9 | 76.6 | 144.2 | 202.7 | 212.6 | 223.3 | 236.1 | 241.0 | 246.0 | 250.9 | 255.8 | 245.4 | 33.73% |
| COAL CAPACITY | 304.5 | 304.5 | 304.5 | 306.4 | 307.2 | 309.6 | 311.9 | 314.3 | 316.7 | 319.0 | 321.4 | 323.7 | 326.4 | 329.1 | 24.6 | 0.71% |
| NUCLEAR CAPACITY | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 95.4 | 95.4 | -1.1 | -0.10% |
| HYDRO CAPACITY | 100.0 | 100.2 | 99.0 | 97.7 | 97.7 | 97.9 | 98.3 | 98.6 | 98.8 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 0.0 | 0.00% |
| OTHER CAPACITY | 7.2 | 7.3 | 6.8 | 6.9 | 7.2 | 8.4 | 9.0 | 9.6 | 10.2 | 10.9 | 11.7 | 12.5 | 13.3 | 14.9 | 8.1 | 7.35% |

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# Expected Policies Scenario

| | Power Generation Capacity (GW) | | | | | | | | | | 2010-2020 | | 1999-2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | Annual % Change | Change | Annual % Change |
| **LOWER-48** | | | | | | | | | | | | | | |
| TOTAL CAPACITY | 977.0 | 982.2 | 987.7 | 993.5 | 999.6 | 1013.3 | 1027.4 | 1042.1 | 1056.6 | 1072.5 | 100.5 | 0.99% | 336.5 | 1.81% |
| OIL/GAS CAPACITY | 436.5 | 439.4 | 442.2 | 445.1 | 447.9 | 451.6 | 455.3 | 458.9 | 462.6 | 466.3 | 32.6 | 0.73% | 237.1 | 3.44% |
| *CT/CC ADDITIONS* | 261.8 | 267.7 | 273.5 | 279.4 | 285.3 | 292.1 | 298.8 | 305.5 | 312.1 | 318.9 | 63.0 | 2.23% | 308.4 | 17.67% |
| COAL CAPACITY | 329.5 | 329.8 | 330.2 | 330.6 | 331.0 | 337.7 | 344.5 | 351.2 | 357.3 | 364.0 | 35.0 | 1.01% | 59.6 | 0.85% |
| NUCLEAR CAPACITY | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 0.0 | 0.00% | -1.1 | -0.05% |
| HYDRO CAPACITY | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 0.0 | 0.00% | 0.0 | 0.00% |
| OTHER CAPACITY | 16.6 | 18.6 | 20.8 | 23.4 | 26.3 | 29.5 | 33.3 | 37.5 | 42.3 | 47.8 | 32.9 | 12.37% | 40.9 | 9.71% |

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# Expected Policies Scenario

**Power Generation Fossil Fuel Consumption (Quads)**

| LOWER-48 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FOSSIL FUEL CONSUMPTION | 22.5 | 23.7 | 23.8 | 24.779 | 24.662 | 24.675 | 24.446 | 24.955 | 25.602 | 26.180 | 26.75 | 27.456 | 28.045 | 28.711 | 4.9 | 1.73% |
| GAS DEMAND | 3.0 | 3.4 | 3.8 | 4.393 | 4.449 | 4.652 | 4.196 | 4.701 | 4.965 | 5.348 | 5.694 | 6.098 | 6.425 | 6.777 | 2.9 | 5.31% |
| Gas Curtailments | 0.0 | 0.0 | 0.0 | 0.010 | 0.039 | 0.006 | 0.000 | 0.002 | 0.000 | 0.000 | 0.000 | 0.002 | 0.000 | 0.001 | 0.0 | 13.00% |
| Cogen Gas Use /1 | 0.0 | 0.0 | 0.0 | 0.120 | 0.280 | 0.466 | 0.525 | 0.600 | 0.655 | 0.748 | 0.818 | 0.889 | 0.955 | 1.019 | 1.0 | 40.77% |
| COAL DEMAND | 18.7 | 19.1 | 19.0 | 19.491 | 19.235 | 19.537 | 19.719 | 20.011 | 20.339 | 20.493 | 20.72 | 20.976 | 21.209 | 21.493 | 2.5 | 1.13% |
| OIL DEMAND | 0.8 | 1.2 | 1.0 | 0.895 | 0.978 | 0.487 | 0.531 | 0.243 | 0.297 | 0.339 | 0.339 | 0.382 | 0.411 | 0.441 | -0.5 | -6.74% |

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

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# Expected Policies Scenario

| | Power Generation Fossil Fuel Consumption (Quads) | | | | | | | | | | 2010-2020 | | 1999-2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | Annual % Change | Change | Annual Change |
| **LOWER-48** | | | | | | | | | | | | | | |
| FOSSIL FUEL CONSUMPTION | 29.405 | 30.093 | 30.591 | 31.193 | 31.770 | 32.485 | 33.083 | 33.750 | 34.404 | 35.193 | 6.5 | 2.06% | 11.417 | 1.88% |
| GAS DEMAND | 7.167 | 7.645 | 8.092 | 8.576 | 9.296 | 9.341 | 9.713 | 9.814 | 9.985 | 10.149 | 3.4 | 4.12% | 6.312 | 4.74% |
| Gas Curtailments | 0.001 | 0.001 | 0.001 | 0.001 | 0.004 | 0.013 | 0.008 | 0.004 | 0.002 | 0.003 | 0.0 | 8.06% | 0.003 | 10.62% |
| Cogen Gas Use /1 | 1.092 | 1.185 | 1.276 | 1.368 | 1.502 | 1.527 | 1.595 | 1.617 | 1.656 | 1.694 | 0.7 | 5.22% | 1.671 | 22.55% |
| COAL DEMAND | 21.739 | 21.912 | 21.992 | 22.027 | 22.038 | 22.403 | 22.784 | 23.225 | 23.647 | 24.140 | 2.6 | 1.17% | 5.151 | 1.15% |
| OIL DEMAND | 0.499 | 0.536 | 0.507 | 0.590 | 0.437 | 0.741 | 0.586 | 0.710 | 0.772 | 0.904 | 0.5 | 7.44% | -0.046 | -0.24% |

1. Cogeneratiion gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

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# Expected Policies Scenario

## Regional Natural Gas Balance (Annual Bcf)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | 1999-2010 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **United States/2,3** | | | | | | | | | | | | | | | | |
| Total Consumption | 21,990 | 21,363 | 22,358 | 23,269 | 21,547 | 22,417 | 21,495 | 21,993 | 22,076 | 21,944 | 22,451 | 23,152 | 23,630 | 24,245 | 1,886 | 0.74% |
| +Storage Injections/1 | 1,886 | 1,993 | 1,656 | 1,533 | 2,380 | 1,637 | 2,406 | 2,045 | 2,097 | 2,313 | 2,294 | 2,234 | 2,265 | 2,231 | 576 | 2.75% |
| + LNG Injections | 76 | 58 | 37 | 56 | 35 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 5 | 1.27% |
| + Pipeline Exports | | | | | | | | | | | | | | | | |
| + Exports to Canada | 529 | 435 | 539 | 581 | 789 | 735 | 883 | 819 | 784 | 806 | 825 | 884 | 897 | 893 | 354 | 4.70% |
| + Exports to Mexico | 33 | 48 | 55 | 100 | 140 | 266 | 340 | 409 | 512 | 461 | 212 | 240 | 240 | 272 | 218 | 15.73% |
| =Total Demand | 24,513 | 23,896 | 24,644 | 25,540 | 24,893 | 25,098 | 25,165 | 25,309 | 25,511 | 25,566 | 25,824 | 26,552 | 27,074 | 27,683 | 3,039 | 1.06% |
| Total Production | 19,207 | 18,862 | 18,922 | 19,088 | 19,383 | 18,734 | 18,528 | 18,414 | 18,382 | 18,488 | 18,744 | 18,889 | 18,916 | 18,985 | 62 | 0.03% |
| + Supplemental Fuels | 103 | 102 | 98 | 86 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | -19 | -1,94% |
| +Storage Withdrawals/1 | 1,919 | 1,470 | 1,797 | 2,380 | 1,231 | 2,080 | 2,211 | 2,328 | 2,393 | 2,051 | 2,027 | 2,194 | 2,188 | 2,273 | 476 | 2.16% |
| + LNG Withdrawals | 68 | 52 | 1 | 5 i | 35 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 3 | 0.80% |
| + Net LNG Imports | 16 | 20 | 100 | 160 | 169 | 164 | 464 | 807 | 1,047 | 1,487 | 1,578 | 1,984 | 2,235 | 2,782 | 2,682 | 35.32% |
| + Ethane Rejection | 5 | 39 | 7 | 0 | 102 | 0 | 87 | 5 | 0 | 27 | 19 | 2 | 1 | 3 | -4 | -7.54% |
| + Pipeline Imports | | | | | | | | | | | | | | | | |
| + Imports from Canada | 3,494 | 3,577 | 3,856 | 3,997 | 4,261 | 4,227 | 4,087 | 3,918 | 3,830 | 3,671 | 3,540 | 3,563 | 3,822 | 3,739 | -117 | -0.28% |
| + Imports from Mexico | 11 | 10 | 50 | 6 | 7 | 0 | 0 | 0 | 0 | 9 | 73 | 53 | 60 | 49 | -2 | -0.29% |
| =Total Supply | 24,822 | 24,131 | 24,866 | 25,769 | 25,266 | 25,324 | 25,496 | 25,592 | 25,770 | 25,852 | 26,099 | 26,804 | 27,340 | 27,949 | 3,083 | 1.07% |
| Balancing Item | 309 | 236 | 222 | 229 | 374 | 226 | 331 | 283 | 259 | 286 | 275 | 252 | 266 | 266 | 43 | 1.62% |

1. Sum of net monthly storage injections/withdrawals.

2. Net LNG Imports line item does not include LNG imports at Baja.

3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

# Expected Policies Scenario

| United States/2,3 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2010-2020 Change | 2010-2020 Annual % Change | 1999-2020 Change | 1999-2020 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Regional Natural Gas Balance (Annual Bcf)** | | | | | | | | | | | | | |
| Total Consumption | 24,810 | 25,467 | 26,086 | 26,759 | 27,857 | 28,006 | 28,520 | 28,985 | 29,323 | 29,570 | 5,326 | 2.01% | 7,212 | 1.34% |
| +Storage Injections/1 | 2,289 | 2,362 | 2,388 | 2,350 | 2,432 | 2,701 | 2,356 | 2,666 | 2,495 | 2,722 | 491 | 2.01% | 1,067 | 2.40% |
| + LNG Injections | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 0 | 0.00% | 5 | 0.66% |
| + Pipeline Exports | | | | | | | | | | | | | | |
| + Exports to Canada | 825 | 855 | 858 | 1,122 | 2,368 | 2,340 | 2,521 | 3,121 | 3,146 | 3,124 | 2,231 | 13.34% | 2,585 | 8.73% |
| + Exports to Mexico | 273 | 273 | 255 | 255 | 255 | 255_ | 255 | 255 | 255 | 255 | -17 | -0.65% | 200 | 7.62% |
| =Total Demand | 28,239 | 29,000 | 29,630 | 30,529 | 32,954 | 33,344 | 33,694 | 35,070 | 35,261 | 35,713 | 8,030 | 2.58% | 11,069 | 1.78% |
| Total Production | 19,071 | 19,239 | 19,286 | 19,524 | 20,688 | 20,524 | 20,614 | 21,158 | 21,110 | 21,124 | 2,139 | 1.07% | 2,201 | 0.53% |
| + Supplemental Fuels | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 0 | 0.00% | -19 | -1.02% |
| + Storage Withdrawals/1 | 2,362 | 2,367 | 2,337 | 2,387 | 2,342 | 2,667 | 2,455 | 2,515 | 2,655 | 2,666 | 393 | 1.61% | 869 | 1.90% |
| + LNG Withdrawals | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 0 | 0.12% | 4 | 0.47% |
| + Net LNG Imports | 3,220 | 3,778 | 4,498 | 4,863 | 5,100 | 5,407 | 5,921 | 6,140 | 6,338 | 6,636 | 3,854 | 9.08% | 6,536 | 22.12% |
| + Ethane Rejection | 5 | 16 | 8 | 11 | 9 | 63 | 14 | 1 | 0 | 20 | 17 | 20.84% | 13 | 5.03% |
| + Pipeline Imports | | | | | | | | | | | | | | |
| + Imports from Canada | 3,691 | 3,714 | 3,597 | 3,846 | 4,969 | 4,830 | 4,833 | 5,395 | 5,312 | 5,382 | 1,643 | 3.71% | 1,527 | 1.60% |
| + Imports from Mexico | 45 | 45 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 34 | 5.45% | 33 | 2.40% |
| =Total Supply | 28,512 | 29,278 | 29,927 | 30,832 | 33,310 | 33,692 | 34,038 | 35,412 | 35,616 | 36,029 | 8,080 | 2.57% | 11,163 | 1.78% |
| Balancing Item | 274 | 278 | 297 | 303 | 356 | 348 | 344 | 342 | 354 | 316 | 50 | 1.74% | 93 | 1.68% |

1. Sum of net monthly storage injections/withdrawals.
2. Net LNG Imports line item does not include LNG imports at Baja.
3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

# Expected Policies Scenario

## Gas Prices (Nominal $/MMBtu)

| Henry Hub | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVG | Std Dev |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1997 | 3.37 | 2.21 | 1.91 | 2.04 | 2.24 | 2.21 | 2.19 | 2.49 | 2.87 | 3.04 | 2.98 | 2.33 | 2.49 | 0.44 |
| 1998 | 2.11 | 2.22 | 2.23 | 2.44 | 2.13 | 2.16 | 2.20 | 1.85 | 1.99 | 1.89 | 2.09 | 1.68 | 2.08 | 0.19 |
| 1999 | 1.84 | 1.77 | 1.80 | 2.13 | 2.26 | 2.30 | 2.29 | 2.79 | 2.57 | 2.70 | 2.31 | 2.36 | 2.26 | 0.32 |
| 2000 | 2.41 | 2.66 | 2.78 | 3.02 | 3.58 | 4.30 | 4.05 | 4.39 | 5.02 | 5.03 | 5.49 | 8.69 | 4.29 | 1.65 |
| 2001 | 8.48 | 5.65 | 5.15 | 5.20 | 4.21 | 3.74 | 3.07 | 3.02 | 2.20 | 2.44 | 2.37 | 2.37 | 3.99 | 1.79 |
| 2002 | 2.32 | 2.28 | 3.02 | 3.39 | 3.52 | 3.22 | 3.04 | 3.13 | 3.55 | 4.13 | 4.06 | 4.74 | 3.37 | 0.68 |
| 2003 | 5.71 | 7.09 | 6.39 | 5.27 | 5.76 | 5.80 | 5.04 | 4.98 | 4.69 | 4.66 | 4.43 | 6.12 | 5.49 | 0.76 |
| 2004 | 6.05 | 5.40 | 5.38 | 4.42 | 5.62 | 5.73 | 7.08 | 6.38 | 5.68 | 4.95 | 5.75 | 5.85 | 5.69 | 0.64 |
| 2005 | 7.03 | 7.29 | 6.87 | 8.94 | 9.21 | 7.67 | 7.55 | 7.14 | 8.05 | 7.55 | 7.72 | 7.91 | 7.74 | 0.69 |
| 2006 | 8.98 | 9.08 | 8.27 | 7.40 | 9.13 | 7.91 | 7.84 | 7.57 | 8.71 | 7.76 | 8.04 | 8.17 | 8.24 | 0.58 |
| 2007 | 8.81 | 8.62 | 8.02 | 6.54 | 6.62 | 6.15 | 6.63 | 6.58 | 6.60 | 4.90 | 6.08 | 6.18 | 6.81 | 1.08 |
| 2008 | 6.70 | 6.62 | 6.08 | 6.68 | 7.04 | 6.44 | 7.09 | 6.96 | 6.46 | 5.54 | 6.37 | 6.48 | 6.54 | 0.41 |
| 2009 | 6.95 | 6.77 | 6.33 | 5.76 | 5.53 | 5.59 | 6.33 | 6.15 | 5.88 | 5.14 | 5.83 | 5.89 | 6.01 | 0.50 |
| 2010 | 6.34 | 6.16 | 5.74 | 6.63 | 6.99 | 5.96 | 5.79 | 5.93 | 6.27 | 4.82 | 5.67 | 5.82 | 6.01 | 0.52 |
| 2011 | 6.45 | 6.35 | 5.75 | 7.24 | 6.72 | 5.94 | 6.14 | 6.05 | 6.60 | 5.47 | 6.11 | 6.22 | 6.25 | 0.45 |
| 2012 | 6.97 | 7.01 | 6.19 | 5.58 | 6.72 | 6.97 | 7.84 | 7.53 | 7.00 | 5.96 | 6.82 | 6.98 | 6.80 | 0.60 |
| 2013 | 7.60 | 7.47 | 6.83 | 6.47 | 6.24 | 5.77 | 5.76 | 5.87 | 6.34 | 4.79 | 5.64 | 5.82 | 6.22 | 0.77 |
| 2014 | 6.52 | 6.52 | 5.91 | 7.48 | 7.87 | 6.68 | 6.78 | 6.82 | 7.71 | 7.27 | 6.81 | 7.42 | 6.98 | 0.55 |
| 2015 | 7.96 | 7.84 | 7.26 | 4.42 | 3.67 | 4.11 | 5.74 | 5.59 | 4.04 | 3.66 | 4.43 | 4.59 | 5.28 | 1.53 |
| 2016 | 5.42 | 5.78 | 5.08 | 11.23 | 9.98 | 9.15 | 8.62 | 8.25 | 8.78 | 6.53 | 7.83 | 8.01 | 7.89 | 1.80 |
| 2017 | 8.52 | 8.47 | 7.86 | 5.85 | 5.53 | 5.19 | 6.05 | 5.69 | 5.60 | 5.19 | 5.54 | 5.65 | 6.26 | 1.20 |
| 2018 | 6.42 | 6.47 | 5.78 | 6.63 | 7.98 | 7.11 | 7.43 | 6.77 | 6.73 | 6.22 | 6.53 | 6.72 | 6.73 | 0.55 |
| 2019 | 7.35 | 7.43 | 6.75 | 7.08 | 7.12 | 6.51 | 7.03 | 6.45 | 6.47 | 5.52 | 6.19 | 6.32 | 6.68 | 0.53 |
| 2020 | 7.21 | 7.49 | 6.69 | 9.09 | 9.79 | 8.50 | 8.60 | 7.72 | 8.58 | 7.83 | 8.05 | 8.21 | 8.15 | 0.81 |

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# Expected Policies Scenario

Gas Prices (2003$/MMBtu)

| Henry Hub | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVG | Std Dev |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1997 | 3.81 | 2.50 | 2.15 | 2.30 | 2.52 | 2.48 | 2.46 | 2.79 | 3.21 | 3.40 | 3.33 | 2.60 | 2.80 | 0.49 |
| 1998 | 2.35 | 2.47 | 2.48 | 2.72 | 2.36 | 2.40 | 2.44 | 2.04 | 2.20 | 2.09 | 2.31 | 1.86 | 2.31 | 0.22 |
| 1999 | 2.03 | 1.94 | 1.98 | 2.33 | 2.48 | 2.51 | 2.51 | 3.04 | 2.81 | 2.94 | 2.51 | 2.56 | 2.47 | 0.34 |
| 2000 | 2.61 | 2.87 | 3.00 | 3.24 | 3.83 | 4.60 | 4.33 | 4.69 | 5.35 | 5.35 | 5.84 | 9.21 | 4.58 | 1.73 |
| 2001 | 8.97 | 5.97 | 5.43 | 5.47 | 4.42 | 3.92 | 3.22 | 3.16 | 2.29 | 2.54 | 2.46 | 2.46 | 4.19 | 1.91 |
| 2002 | 2.40 | 2.36 | 3.12 | 3.48 | 3.62 | 3.30 | 3.11 | 3,19 | 3.62 | 4.20 | 4.12 | 4.80 | 3.44 | 0.68 |
| 2003 | 5.77 | 7.14 | 6.43 | 5.29 | 5.78 | 5.80 | 5.02 | 4.95 | 4.66 | 4.62 | 4.38 | 6.05 | 5.49 | 0.78 |
| 2004 | 5.96 | 5.31 | 5.28 | 4.33 | 5.49 | 5.59 | 6.89 | 6.20 | 5.51 | 4.79 | 5.55 | 5.64 | 5.55 | 0.62 |
| 2005 | 6.76 | 7.00 | 6.58 | 8.55 | 8.78 | 7.30 | 7.17 | 6.76 | 7.62 | 7.13 | 7.27 | 7.43 | 7.36 | 0.65 |
| 2006 | 8.43 | 8.51 | 7.73 | 6.90 | 8.49 | 7.34 | 7.27 | 7.00 | 8.04 | 7.15 | 7.39 | 7.50 | 7.65 | 0.56 |
| 2007 | 8.06 | 7.87 | 7.31 | 5.95 | 6.01 | 5.57 | 6.00 | 5.94 | 5.95 | 4.40 | 5.45 | 5.53 | 6.17 | 1.02 |
| 2008 | 5.98 | 5.90 | 5.41 | 5.92 | 6.24 | 5.69 | 6.25 | 6.13 | 5.67 | 4.85 | 5.57 | 5.65 | 5.77 | 0.38 |
| 2009 | 6.05 | 5.88 | 5.49 | 4.99 | 4.77 | 4.82 | 5.45 | 5.29 | 5.04 | 4.40 | 4.98 | 5.01 | 5.18 | 0.45 |
| 2010 | 5.39 | 5.22 | 4.86 | 5.60 | 5.89 | 5.02 | 4.86 | 4.97 | 5.24 | 4.02 | 4.72 | 4.84 | 5.05 | 0.46 |
| 2011 | 5.34 | 5.26 | 4.74 | 5.96 | 5.53 | 4.87 | 5.03 | 4.95 | 5.38 | 4.45 | 4.96 | 5.04 | 5.13 | 0.38 |
| 2012 | 5.64 | 5.66 | 4.99 | 4.48 | 5.39 | 5.58 | 6.26 | 6.00 | 5.57 | 4.74 | 5.40 | 5.52 | 5.44 | 0.48 |
| 2013 | 6.00 | 5.89 | 5.37 | 5.08 | 4.88 | 4.51 | 4.49 | 4.56 | 4.92 | 3.71 | 4.36 | 4.49 | 4.86 | 0.63 |
| 2014 | 5.02 | 5.01 | 4.53 | 5.72 | 6.01 | 5.09 | 5.16 | 5.18 | 5.84 | 5.50 | 5.13 | 5.59 | 5.32 | 0.40 |
| 2015 | 5.98 | 5.88 | 5.43 | 3.30 | 2.73 | 3.05 | 4.26 | 4.14 | 2.99 | 2.70 | 3.26 | 3.37 | 3.92 | 1.16 |
| 7AdC | n n~ | 4.22 | 3.71 | 8.18 | 7.26 | 6.64 | 6.24 | 5.96 | 6.33 | 4.70 | 5.62 | 5.74 | 5.71 | 1.30 |
| 2017 | 6.09 | 6.04 | 5.60 | 4.16 | 3.92 | 3.67 | 4.27 | 4.01 | 3.94 | 3.65 | 3.88 | 3.95 | 4.43 | 0.88 |
| 2018 | 4.48 | 4.50 | 4.01 | 4.60 | 5.52 | 4.91 | 5.12 | 4.66 | 4.62 | 4.26 | 4.46 | 4.58 | 4.64 | 0.38 |
| 2019 | 5.01 | 5.04 | 4.58 | 4.79 | 4.81 | 4.39 | 4.73 | 4.33 | 4.33 | 3.69 | 4.13 | 4.20 | 4.50 | 0.38 |
| 2020 | 4.79 | 4.96 | 4.42 | 6.00 | 6.45 | 5.59 | 5.64 | 5.05 | 5.61 | 5.10 | 5.24 | 5.33 | 5.35 | 0.53 |

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# APPENDIX II

# EXPANDED POLICIES SCENARIO

# Expanded Policies Scenario

## Regional Natural Gas Consumption (Bcf)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **United States** | | | | | | | | | | | | | | | | |
| Total Consumption | 21,990 | 21,363 | 22,359 | 23,270 | 21,548 | 22,419 | 21,497 | 21,988 | 22,069 | 22,026 | 22,540 | 23,260 | 24,145 | 24,638 | 2279 | 0.89% |
| Residential | 4,983 | 4,393 | 4,651 | 4,958 | 4,688 | 4,810 | 5,037 | 5,038 | 5,092 | 5,110 | 5,155 | 5,250 | 5,305 | 5,419 | 767 | 1.40% |
| Commercial | 3,222 | 2,928 | 3,070 | 3,240 | 3,067 | 3,123 | 3,191 | 3,153 | 3,172 | 3,147 | 3,166 | 3,227 | 3,280 | 3,393 | 323 | 0.91% |
| Industrial | 8,904. | 8,828 | 8,944 | 8,828 | 7,496 | 7,995 | 7,196 | 7,225 | 7,058 | 6,669 | 6,811 | 6,987 | 7,238 | 7,315 | -1629 | -1.81% |
| *Cogeneration/1* | 1,481 | 1,474 | 1,492 | 1,471 | 1,179 | 1,249 | 1,116 | 1,125 | 1,096 | 1,018 | 1,036 | 1,062 | 1,102 | 1,119 | -374 | -2.59% |
| Power Generation | 2,963 | 3,340 | 3,766 | 4,288 | 4,315 | 4,542 | 4,107 | 4,588 | 4,812 | 5,149 | 5,432 | 5,790 | 6,287 | 6,481 | 2716 | 5.06% |
| *Cogeneration /1* | 0 | 0 | 24 | 120 | 280 | 466 | 525 | 599 | 647 | 734 | 793 | 858 | 948 | 993 | 969 | 40.44% |
| Pipeline Fuel | 697 | 662 | 708 | 726 | 737 | 729 | 754 | 746 | 729 | 741 | 758 | 780 | 809 | 804 | 96 | 1.16% |
| Lease & Plant | 1,221 | 1,212 | 1,220 | 1,230 | 1,246 | 1,220 | 1,211 | 1,207 | 1,206 | 1,210 | 1,217 | 1,226 | 1,226 | 1,226 | 6 | 0.04% |
| *Cogeneration Total* | 1,481 | 1,474 | 1,516 | 1,591 | 1,459 | 1,714 | 1,641 | 1,723 | 1,743 | 1,751 | 1,829 | 1,920 | 2,050 | 2,112 | 595 | 3.06% |

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity onstructed from 1999 forward is reported in the Power Generation sector.

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# Expanded Policies Scenario

| | Regional Natural Gas Consumption (Bcf) | | | | | | | | | | 2010-2020 | | 1999-2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | Annual % Change | Change | Annual % Change |
| **United States** | | | | | | | | | | | | | | |
| Total Consumption | 25,617 | 25,594 | 26,031 | 26,414 | 27,383 | 27,521 | 27,668 | 28,762 | 28,969 | 29,584 | 4947 | 1.85% | 7225 | 1.34% |
| Residential | 5,529 | 5,660 | 5,695 | 5,764 | 5,831 | 5,947 | 5,993 | 6,066 | 6,158 | 6,230 | 812 | 1.41% | 1579 | 1.40% |
| Commercial | 3,500 | 3,609 | 3,629 | 3,673 | 3,711 | 3,791 | 3,824 | 3,867 | 3,936 | 3,955 | 562 | 1.55% | 885 | 1.21% |
| Industrial | 7,511 | 7,336 | 7,335 | 7,476 | 7,761 | 7,711 | 7,613 | 7,971 | 7,963 | 8,027 | 712 | 0.93% | -917 | -0.51% |
| Cogeneration /1 | 1,145 | 1,123 | 1,113 | 1,143 | 1,182 | 1,181 | 1,157 | 1,218 | 1,220 | 1,227 | 109 | 0.93% | -265 | -0.93% |
| Power Generation | 7,036 | 6,980 | 7,346 | 7,461 | 7,996 | 8,009 | 8,173 | 8,734 | 8,813 | 9,248 | 2767 | 3.62% | 5483 | 4.37% |
| Cogeneration/1 | 1,088 | 1,089 | 1,158 | 1,184 | 1,282 | 1,288 | 1,341 | 1,425 | 1,447 | 1,521 | 528 | 4.35% | 1497 | 21.92% |
| Pipeline Fuel | 807 | 791 | 800 | 822 | 875 | 875 | 881 | 934 | 927 | 948 | 143 | 1.65% | 239 | 1.39% |
| Lease & Plant | 1,234 | 1,218 | 1,227 | 1,218 | 1,209 | 1,188 | 1,183 | 1,188 | 1,173 | 1,176 | -50 | -0.42% | -44 | -0.18% |
| Cogeneration Total | 2,233 | 2,212 | 2,270 | 2,328 | 2,464 | 2,469 | 2,498 | 2,643 | 2,667 | 2,748 | 637 | 2.67% | 1232 | 2.87% |

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

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# Expanded Policies Scenario

| U.S. Total | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2001-2010 Change | 2001-2010 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Regional Industrial Natural Gas Consumption (Bcf) | | | | | | | | | | | |
| **Total of All Industrial Sectors** | | | | | | | | | | | | |
| Total of All End Uses | 7,545 | 8,005 | 7,197 | 7,258 | 7,058 | 6,669 | 6,811 | 6,989 | 7,241 | 7,320 | -225 | -0.34% |
| Boilers | 2,479 | 2,573 | 2,424 | 2,501 | 2,467 | 2,458 | 2,528 | 2,583 | 2,681 | 2,699 | 220 | 0.95% |
| Process Heat | 2,635 | 2,825 | 2,528 | 2,558 | 2,488 | 2,259 | 2,300 | 2,374 | 2,463 | 2,491 | -144 | -0.62% |
| Other Uses | 1,752 | 1,850 | 1,661 | 1,673 | 1,638 | 1,513 | 1,541 | 1,585 | 1,645 | 1,673 | -79 | -0.51% |
| Cogen Gas Use /1 | 1,179 | 1,249 | 1,116 | 1,125 | 1,096 | 1,018 | 1,036 | 1,062 | 1,102 | 1,119 | -60 | -0.58% |
| Ammonia Feedstock | 370 | 426 | 320 | 281 | 237 | 217 | 216 | 216 | 216 | 215 | -155 | -5.84% |
| Methanol Feedstock | 157 | 173 | 102 | 78 | 57 | 44 | 44 | 44 | 44 | 43 | -115 | -13.47% |
| Hydrogen Feedstock | 152 | 157 | 162 | 167 | 172 | 177 | 182 | 188 | 193 | 199 | 47 | 3.05% |
| **Food** | | | | | | | | | | | | |
| Total of All End Uses | 599 | 623 | 586 | 585 | 583 | 549 | 557 | 571 | 583 | 592 | -7 | -0.13% |
| Boilers | 223 | 229 | 226 | 229 | 232 | 231 | 234 | 237 | 240 | 242 | 19 | 0.90% |
| Process Heat | 226 | 237 | 214 | 211 | 209 | 189 | 192 | 198 | 204 | 208 | -18 | -0.93% |
| Other Uses | 150 | 158 | 146 | 145 | 143 | 129 | 131 | 136 | 139 | 142 | -8 | -0.58% |
| **Paper** | | | | | | | | | | | | |
| Total of All End Uses | 590 | 595 | 595 | 602 | 604 | 588 | 586 | 587 | 585 | 583 | -7 | -0.13% |
| Boilers | 410 | 413 | 414 | 418 | 418 | 414 | 417 | 419 | 420 | 420 | 10 | 0.27% |
| Process Heat | 55 | 55 | 55 | 56 | 56 | 53 | 51 | 51 | 50 | 49 | -6 | -1.19% |
| Other Uses | 125 | 126 | 126 | | 130 | 121 | 118 | 117 | 115 | 114 | -11 | -1.05% |
| **Petroleum Refining** | | | | | | | | | | | | |
| Total of All End Uses | 1,351 | 1,414 | 1,309 | 1,274 | 1,240 | 1,130 | 1,144 | 1,163 | 1,179 | 1,192 | -159 | -1.38% |
| Boilers | 354 | 358 | 357 | 362 | 364 | 363 | 366 | 368 | 370 | 371 | 17 | 0.52% |
| Process Heat | 797 | 846 | 759 | 727 | 698 | 610 | 619 | 633 | 644 | 652 | -145 | -2.21% |
| Other Uses | 199 | 211 | 192 | 185 | 179 | 157 | 159 | 162 | 165 | 169 | -31 | -1.84% |

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

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**Regional Industrial Natural Gas Consumption (Bcf)**

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2001-2020 Change | 2001-2020 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total of All Industrial Sectors** | | | | | | | | | | | | |
| Total of All End Uses | 7,517 | 7,341 | 7,341 | 7,480 | 7,767 | 7,713 | 7,616 | 7,975 | 7,965 | 8,031 | 487 | 0.33% |
| Boilers | 2,791 | 2,712 | 2,767 | 2,778 | 2,917 | 2,866 | 2,848 | 2,976 | 2,954 | 2,977 | 498 | 0.97% |
| Process Heat | 2,552 | 2,497 | 2,464 | 2,537 | 2,624 | 2,613 | 2,568 | 2,698 | 2,698 | 2,722 | 87 | 0.17% |
| Other Uses | 1,711 | 1,681 | 1,660 | 1,713 | 1,768 | 1,772 | 1,735 | 1,828 | 1,833 | 1,846 | 95 | 0.28% |
| Cogen Gas Use /1 | **1,145** | **1,123** | **1,113** | **1,143** | **1,182** | **1,181** | **1,157** | **1,218** | **1,220** | **1,227** | **48** | **0.21%** |
| Ammonia Feedstock | 215 | 210 | 207 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | -165 | -3.06% |
| Methanol Feedstock | 42 | 30 | 25 | 23 | 22 | 20 | 15 | 15 | 15 | 14 | -144 | -12.08% |
| Hydrogen Feedstock | 205 | 211 | 218 | 224 | 231 | 238 | 245 | 252 | 260 | 268 | 116 | 3.02% |
| **Food** | | | | | | | | | | | | |
| Total of All End Uses | 598 | 602 | 599 | 616 | 621 | 630 | 628 | 642 | 649 | 655 | 56 | 0.47% |
| Boilers | 244 | 245 | 247 | 250 | 252 | 254 | 256 | 259 | 261 | 263 | 40 | 0.87% |
| Process Heat | 210 | 212 | 209 | 218 | 219 | 223 | 221 | 228 | 230 | 233 | 6 | 0.15% |
| Other Uses | 144 | 145 | 143 | 149 | 150 | 153 | 151 | 156 | 158 | 159 | 9 | 0.32% |
| **Paper** | | | | | | | | | | | | |
| Total of All End Uses | 579 | 574 | 565 | 568 | 564 | 565 | 557 | 560 | 559 | 556 | -34 | -0.31% |
| Boilers | 421 | 419 | 419 | 420 | 422 | 422 | 421 | 422 | 422 | 423 | 13 | 0.16% |
| Process Heat | 48 | 47 | 44 | 44 | 43 | 43 | 41 | 42 | 41 | 40 | -15 | -1.61% |
| Other Uses | 111 | 108 | 102 | | 100 | 100 | 95 | 96 | 95 | 93 | -32 | -1.54% |
| **Petroleum Refining** | | | | | | | | | | | | |
| Total of All End Uses | 1,199 | 1,203 | 1,195 | 1,219 | 1,224 | 1,235 | 1,232 | 1,249 | 1,257 | 1,264 | -86 | -0.35% |
| Boilers | 372 | 374 | 375 | 377 | 379 | 380 | 382 | 383 | 385 | 386 | 32 | 0.46% |
| Process Heat | 657 | 659 | 653 | 669 | 672 | 679 | 677 | 688 | 693 | 698 | -99 | -0.70% |
| Other Uses | 169 | 170 | 168 | 173 | 173 | 175 | 173 | 177 | 179 | 180 | -19 | -0.53% |

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

# Expanded Policies Scenario

## Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2001-2010 Change | 2001-2010 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Chemicals** | | | | | | | | | | | | |
| Total of All End Uses | 2,602 | 2,986 | 2,470 | 2,512 | 2,354 | 2,272 | 2,371 | 2,462 | 2,644 | 2,665 | 64 | 0.27% |
| Boilers | 822 | 910 | 781 | 828 | 783 | 780 | 831 | 869 | 951 | 959 | 136 | 1.72% |
| Process Heat | 549 | 676 | 569 | 606 | 574 | 545 | 573 | 602 | 658 | 662 | 113 | 2.10% |
| Other Uses | 551 | 643 | 538 | 552 | 530 | 508 | 526 | 544 | 582 | 588 | 36 | 0.71% |
| Ammonia Feedstock | 370 | 426 | 320 | 281 | 237 | 217 | 216 | 216 | 216 | 215 | -155 | -5.84% |
| Methanol Feedstock | 157 | 173 | 102 | 78 | 57 | 44 | 44 | 44 | 44 | 43 | -115 | -13.47% |
| Hydrogen Feedstock | 152 | 157 | 162 | 167 | 172 | 177 | 182 | 188 | 193 | 199 | 47 | 3.05% |
| **Stone, Clay and Glass** | | | | | | | | | | | | |
| Total of All End Uses | 349 | 369 | 340 | 344 | 345 | 316 | 323 | 337 | 348 | 359 | 10 | 0.31 |
| Boilers | 17 | 18 | 17 | 18 | 18 | 18 | 19 | 19 | 20 | 20 | 3 | 1.70% |
| Process Heat | 287 | 303 | 278 | 282 | 282 | 257 | 263 | 274 | 284 | 292 | 5 | 0.19% |
| Other Uses | 44 | 47 | 44 | 44 | 45 | 41 | 42 | 43 | 45 | 47 | 2 | 0.53% |
| Iron and Steel | | | | | | | | | | | | |
| Total of All End Uses | 318 | 334 | 338 | 369 | 369 | 339 | 332 | 333 | 332 | 330 | 12 | 0.41% |
| Boilers | 50 | 53 | 56 | 60 | 61 | 60 | 60 | 61 | 61 | 61 | 11 | 2.31 |
| Process Heat | 237 | 248 | 248 | 272 | 272 | 246 | 240 | 240 | 239 | 236 | 0 | -0.02% |
| Other Uses | 31 | 33 | 34 | 36 | 37 | 33 | 32 | 32 | 32 | 32 | 1 | 0.34% |
| **Primary Aluminum** | | | | | | | | | | | | |
| Total of All End Uses | 89 | 85 | 82 | | 81 | 72 | 71 | 73 | 73 | 74 | -16 | -2.10% |
| Boilers | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 0 | 0.24% |
| Process Heat | 73 | 70 | 67 | 66 | 65 | 57 | 56 | 58 | 58 | 59 | -15 | -2.47% |
| Other Uses | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | -1 | -2.17% |
| *Other Primary Metals* | | | | | | | | | | | | |
| Total of All End Uses | 191 | 169 | 137 | 137 | 134 | 120 | 120 | 123 | 126 | 128 | -63 | -4.35% |
| Boilers | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -1 | -2.38% |
| Process Heat | 105 | 93 | 74 | 74 | 72 | 64 | 65 | 66 | 68 | 69 | -36 | -4.60% |
| Other Uses | 81 | 72 | 59 | 58 | 58 | 51 | 52 | 53 | 54 | 55 | -26 | -4.18% |

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# Expanded Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2001-2020 Change | Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Chemicals** | | | | | | | | | | | | |
| Total of All End Uses | 2,830 | 2,638 | 2,687 | 2,700 | 2,962 | 2,842 | 2,773 | 3,023 | 2,959 | 2,982 | 380 | 0.72% |
| Boilers | 1,037 | 952 | 996 | 989 | 1,112 | 1,047 | 1,019 | 1,126 | 1,089 | 1,096 | 274 | 1.52% |
| Process Heat | 711 | 651 | 659 | 666 | 749 | 709 | 687 | 767 | 744 | 752 | 203 | 1.67% |
| Other Uses | 619 | 583 | 583 | 592 | 643 | 624 | 602 | 658 | 646 | 648 | 96 | 0.85% |
| Ammonia Feedstock | 215 | 210 | 207 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | -165 | -3.06% |
| Methanol Feedstock | 42 | 30 | 25 | 23 | 22 | 20 | 15 | 15 | 15 | 14 | -144 | -12.08% |
| Hydrogen Feedstock | 205 | 211 | 218 | 224 | 231 | 238 | 245 | 252 | 260 | 268 | 116 | 3.02% |
| **Stone, Clay and Glass** | | | | | | | | | | | | |
| Total of All End Uses | 365 | 371 | 369 | 387 | 393 | 402 | 403 | 418 | 427 | 435 | 86 | 1.17% |
| Boilers | 20 | 21 | 21 | 21 | 22 | 22 | 22 | 23 | 23 | 24 | 7 | 1.71% |
| Process Heat | 298 | 302 | 301 | 315 | 320 | 328 | 328 | 341 | 348 | 355 | 67 | 1.12% |
| Other Uses | 47 | 48 | 48 | 50 | 51 | 52 | 52 | 54 | 56 | 57 | 12 | 1.30% |
| Iron and Steel | | | | | | | | | | | | |
| Total of All End Uses | 327 | 323 | 304 | 316 | 309 | 314 | 298 | 306 | 309 | 307 | -11 | -0.19% |
| Boilers | 62 | 61 | 61 | 62 | 62 | 62 | 62 | 63 | 63 | 63 | 13 | 1.20% |
| Process Heat | 234 | 230 | 214 | 224 | 218 | 222 | 208 | 215 | 217 | 215 | -22 | -0.51% |
| Other Uses | 31 | 31 | 29 | 30 | 29 | 30 | 28 | 29 | 29 | 29 | -2 | -0.32% |
| **Primary Aluminum** | | | | | | | | | | | | |
| Total of All End Uses | 72 | 69 | 61 | | 60 | 61 | 56 | 57 | 57 | 55 | -34 | -2.48% |
| Boilers | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 10 | 0 | -0.07% |
| Process Heat | 57 | 55 | 47 | 49 | 46 | 47 | 42 | 43 | 43 | 42 | -32 | -2.92% |
| Other Uses | 4 | 4 | 3 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | -2 | -2.79% |
| **Other Primary Metals** | | | | | | | | | | | | |
| Total of All End Uses | 129 | 129 | 126 | 131 | 130 | 132 | 130 | 133 | 134 | 134 | -57 | -1.85% |
| Boilers | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -1 | -1.03% |
| Process Heat | 69 | 69 | 68 | 70 | 70 | 71 | 70 | 71 | 72 | 72 | -33 | -1.96% |
| Other Uses | 55 | 55 | 54 | 56 | 56 | 57 | 55 | 57 | 58 | 58 | -23 | -1.76% |

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# Expanded Policies Scenario

**Regional Industrial Natural Gas Consumption (Bcf)**

| U.S. Total | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2001-2010 Change | 2001-2010 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 869 | 837 | 770 | 766 | 762 | 721 | 733 | 750 | 767 | 782 | -87 | -1.17% |
| Boilers | 358 | 348 | 334 | 340 | 342 | 342 | 347 | 352 | 357 | 361 | 3 | 0.10% |
| Process Heat | 209 | 198 | 174 | 172 | 169 | 152 | 155 | 161 | 166 | 170 | -39 | -2.27% |
| Other Uses | 303 | 290 | 262 | 253 | 250 | 226 | 231 | 238 | 244 | 251 | -51 | -2.04% |
| **Non-Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 587 | 592 | 571 | 588 | 586 | 562 | 573 | 589 | 603 | 616 | 29 | 0.54% |
| Boilers | 228 | 229 | 224 | 231 | 234 | 235 | 239 | 243 | 247 | 250 | 22 | 1.01% |
| Process Heat | 96 | 98 | 92 | 93 | 91 | 86 | 88 | 91 | 93 | 95 | -2 | -0.20% |
| Other Uses | 262 | 265 | 255 | 265 | 261 | 241 | 246 | 256 | 264 | 271 | 9 | 0.38% |
| **Industrial Curtailments** | **49** | **10** | **1** | **2** | **0** | **0** | **0** | **2** | **3** | **5** | **-44** | **-22.46%** |

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# Expanded Policies Scenario

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2001-2020 Change | 2001-2020 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Regional Industrial Natural Gas Consumption (Bcf) | | | | | | | | | | | |
| **Other Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 794 | 801 | 802 | 829 | 843 | 862 | 866 | 895 | 914 | 932 | 63 | 0.37% |
| Boilers | 366 | 369 | 374 | 381 | 388 | 394 | 400 | 409 | 416 | 424 | 66 | 0.90% |
| Process Heat | 172 | 174 | 173 | 181 | 184 | 188 | 188 | 196 | 200 | 205 | -4 | -0.10% |
| Other Uses | 255 | 258 | 255 | 268 | 271 | 279 | 278 | 290 | 297 | 303 | 0 | 0.00% |
| **Non-Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 625 | 631 | 631 | 652 | 660 | 671 | 674 | 691 | 701 | 711 | 124 | 1.02% |
| Boilers | 253 | 256 | 259 | 262 | 266 | 269 | 272 | 276 | 280 | 283 | 55 | 1.15% |
| Process Heat | 96 | 97 | 97 | 101 | 102 | 104 | 104 | 107 | 109 | 111 | 14 | 0.73% |
| Other Uses | 275 | 278 | 275 | 288 | 292 | 298 | 297 | 307 | 312 | 317 | 55 | 1.01% |
| **Industrial Curtailments** | **6** | **5** | **6** | **4** | **6** | **2** | **3** | **3** | **2** | **4** | **-43** | **-10.41%** |

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# Expanded Policies Scenario

Power Generation Capacity (GW)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **LOWER-48** | | | | | | | | | | | | | | | | |
| TOTAL | 723.2 | 727.4 | 736.0 | 763.8 | 799.9 | 865.1 | 920.9 | 928.4 | 937.6 | 954.8 | 960.8 | 966.5 | 971.9 | 979.2 | 243.2 | 2.63% |
| OIL/GAS CAPACITY | 215.1 | 218.9 | 229.1 | 256.4 | 291.4 | 352.6 | 405.0 | 408.8 | 413.5 | 426.0 | 427.9 | 429.8 | 431.7 | 433.6 | 204.5 | 5.97% |
| *CT/CC ADDITIONS* | *0.0* | 2.1 | 10.5 | 35.9 | 76.6 | 144.2 | 202.7 | 212.6 | 223.3 | 236.1 | 241.0 | 246.0 | 250.9 | 255.8 | 245.4 | 33.73% |
| COAL CAPACITY | 304.5 | 304.5 | 304.5 | 306.4 | 307.2 | 309.6 | 311.9 | 314.3 | 316.7 | 319.0 | 321.4 | 323.7 | 326.4 | 329.1 | 24.6 | 0.71% |
| NUCLEAR CAPACITY | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.6 | 96.6 | 97.1 | 98.5 | 99.8 | 100.8 | 101.5 | 101.4 | 102.0 | 5.5 | 0.51% |
| HYDRO CAPACITY | 100.0 | 100.2 | 99.0 | 97.7 | 97.7 | 97.9 | 98.3 | 98.6 | 98.8 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 0.0 | 0.00% |
| OTHER CAPACITY | 7.2 | 7.3 | 6.8 | 6.9 | 7.2 | 8.4 | 9.0 | 9.6 | 10.2 | 10.9 | 11.7 | 12.5 | 13.3 | 15.4 | 8.6 | 7.70% |

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# Expanded Policies Scenario

**Power Generation Capacity (GW)**

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2010-2020 Change | 2010-2020 Annual % Change | 1999-2020 Change | 1999-2020 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **LOWER-48** | | | | | | | | | | | | | | |
| TOTAL CAPACITY | 987.5 | 996.6 | 1006.8 | 1018.6 | 1029.3 | 1039.4 | 1048.8 | 1057.2 | 1065.9 | 1074.8 | 95.7 | 0.94% | 338.9 | 1.82% |
| OIL/GAS CAPACITY | 433.8 | 434.0 | 434.1 | 434.3 | 434.5 | 434.8 | 435.1 | 435.4 | 435.8 | 436.1 | 2.5 | 0.06% | 206.9 | 3.11% |
| *CT/CC ADDITIONS* | 259.1 | 262.3 | 265.5 | 268.7 | 271.9 | 275.3 | 278.6 | 282.0 | 285.3 | 288.7 | 32.8 | 1.21% | 278.2 | 17.12% |
| COAL CAPACITY | 333.4 | 337.8 | 342.2 | 346.6 | 350.9 | 355.5 | 360.2 | 364.8 | 369.4 | 374.0 | 45.0 | 1.29% | 69.6 | 0.98% |
| NUCLEAR CAPACITY | 102.3 | 102.8 | 103.5 | 104.5 | 105.0 | 106.5 | 107.8 | 107.9 | 107.9 | 107.9 | 5.9 | 0.56% | 11.4 | 0.53% |
| HYDRO CAPACITY | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 0.0 | 0.00% | 0.0 | 0.00% |
| OTHER CAPACITY | 18.9 | 22.9 | 27.9 | 34.2 | 39.9 | 43.6 | 46.7 | 50.1 | 53.7 | 57.8 | 42.4 | 14.12% | 51.0 | 10.71% |

# Expanded Policies Scenario

**Power Generation Fossil Fuel Consumption (Quads)**

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | 1999-2010 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **LOWER-48** | | | | | | | | | | | | | | | | |
| FOSSIL FUEL CONSUMPTION | 22.5 | 23.7 | 23.8 | 24.779 | 24.662 | 24.674 | 24.441 | 24.934 | 25.502 | 25.968 | 26.473 | 27.106 | 27.625 | 28.228 | 4.5 | 1.57% |
| GAS DEMAND | 3.0 | 3.4 | 3.8 | 4.393 | 4.449 | 4.651 | 4.196 | 4.692 | 4.920 | 5.266 | 5.556 | 5.925 | 6.436 | 6.636 | 2.8 | 5.11% |
| *Gas Curtailments* | *0.0* | *0.0* | *0.0* | *0.010* | *0.039* | *0.006* | *0.000* | *0.002* | *0.000* | *0.000* | *0.000* | *0.002* | *0.002* | *0.002* | *0.0* | 16.94% |
| *Cogen Gas Use /1* | *0.0* | *0.0* | *0.0* | *0.120* | *0.280* | *0.466* | *0.525* | *0.599* | *0.647* | *0.734* | *0.793* | *0.858* | *0.948* | *0.993* | *1.0* | 40.44% |
| COAL DEMAND | 18.7 | 19.1 | 19.0 | 19.491 | 19.235 | 19.536 | 19.714 | 20.002 | 20.295 | 20.393 | 20.614 | 20.851 | 20.967 | 21.322 | 2.3 | 1.06% |
| OIL DEMAND | 0.8 | 1.2 | 1.0 | 0.895 | 0.978 | 0.487 | 0.531 | 0.240 | 0.287 | 0.310 | 0.302 | 0.330 | 0.221 | 0.270 | -0.7 | -10.80% |

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

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# Expanded Policies Scenario

| LOWER-48 | Power Generation Fossil Fuel Consumption (Quads) | | | | | | | | | | 2010-2020 | | 1999-2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | Annual % Change | Change | Annual % Change |
| FOSSIL FUEL CONSUMPTION | 28.854 | 29.624 | 30.111 | 30.676 | 31.225 | 31.890 | 32.388 | 33.038 | 33.704 | 34.516 | 6.3 | 2.03% | 10.739 | 1.79% |
| GAS DEMAND | 7.207 | 7.147 | 7.523 | 7.639 | 8.193 | 8.202 | 8.369 | 8.947 | 9.024 | 9.474 | 2.8 | 3.62% | 5.637 | 4.40% |
| Gas Curtailments | 0.002 | 0.002 | 0.001 | 0.002 | 0.007 | 0.003 | 0.003 | 0.005 | 0.002 | 0.006 | 0.0 | 10.30% | 0.005 | 13.73% |
| Cogen Gas Use /1 | 1.088 | 1.089 | 1.158 | 1.184 | 1.282 | 1.288 | 1.341 | 1.425 | 1.447 | 1.521 | 0.5 | 4.35% | 1.497 | 21.92% |
| COAL DEMAND | 21.435 | 22.040 | 22.287 | 22.599 | 22.754 | 23.251 | 23.543 | 23.767 | 24.175 | 24.536 | 3.2 | 1.41% | 5.546 | 1.23% |
| OIL DEMAND | 0.213 | 0.437 | 0.301 | 0.438 | 0.278 | 0.438 | 0.476 | 0.324 | 0.504 | 0.506 | 0.2 | 6.47% | -0.444 | -2.96% |

*1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.*
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# Expanded Policies Scenario

Regional Natural Gas Balance (Annual Bcf)

| United States/2,3 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Annual Change | Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Consumption | 21,990 | 21,363 | 22,358 | 23,269 | 21,547 | 22,417 | 21,495 | 21,986 | 22,066 | 22,023 | 22,538 | 23,258 | 24,143 | 24,636 | 2,277 | 0.89% |
| +Storage Injections/1 | 1,886 | 1,993 | 1,656 | 1,533 | 2,380 | 1,637 | 2,406 | 2,048 | 2,106 | 2,328 | 2,293 | 2,252 | 2,259 | 2,343 | 687 | 3.21% |
| + LNG Injections | 76 | 58 | 37 | 56 | 35 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 5 | 1.27% |
| + Pipeline Exports | | | | | | | | | | | | | | | | |
| + Exports to Canada | 529 | 435 | 539 | 581 | 789 | 735 | 882 | 819 | 784 | 814 | 829 | 874 | 920 | 905 | 366 | 4.83% |
| + Exports to Mexico | 33 | 48 | 55 | 100 | 140 | 266 | 340 | 409 | 512 | 461 | 212 | 240 | 240 | 272 | 218 | 15.73% |
| =Total Demand | 24,513 | 23,896 | 24,644 | 25,540 | 24,893 | 25,097 | 25,165 | 25,304 | 25,510 | 25,668 | 25,915 | 26,666 | 27,604 | 28,198 | 3,554 | 1.23% |
| Total Production | 19,207 | 18,862 | 18,922 | 19,088 | 19,383 | 18,734 | 18,528 | 18,414 | 18,415 | 18,622 | 18,815 | 19,010 | 19,048 | 19,020 | 97 | 0.05% |
| + Supplemental Fuels | 103 | 102 | 98 | 86 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | -19 | -1.94% |
| +Storage Withdrawals/1 | 1,919 | 1,470 | 1,797 | 2,380 | 1,231 | 2,080 | 2,211 | 2,325 | 2,370 | 2,053 | 2,073 | 2,228 | 2,179 | 2,332 | 535 | 2.40% |
| + LNG Withdrawals | 68 | 52 | 36 | 51 | 35 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 3 | 0.80% |
| + Net LNG Imports | 16 | 20 | 100 | 160 | 169 | 164 | 464 | 807 | 1,047 | 1,487 | 1,578 | 1,984 | 2,673 | 3,293 | 3,193 | 37.41% |
| + Ethane Rejection | 5 | 39 | 7 | 0 | 102 | 0 | 87 | 5 | 0 | 11 | 6 | 0 | 0 | 0 | -7 | -100.00% |
| + Pipeline Imports | | | | | | | | | | | | | | | | |
| + Imports from Canada | 3,494 | 3,577 | 3,856 | 3,997 | 4,261 | 4,227 | 4,087 | 3,916 | 3,821 | 3,640 | 3,520 | 3,524 | 3,777 | 3,649 | -207 | -0.50% |
| + Imports from Mexico | 11 | 10 | 50 | | | 0 | 0 | 0 | 0 | 9 | 73 | 53 | 60 | 49 | -2 | -0.29% |
| =Total Supply | 24,822 | 24,131 | 24,866 | 25,[illegible] | | 25,324 | 25,496 | 25,587 | 25,772 | 25,940 | 26,183 | 26,919 | 27,856 | 28,461 | 3,595 | 1.24% |
| Balancing Item | 309 | 236 | 222 | 229 | 374 | 226 | 330 | 283 | 262 | 272 | 268 | 253 | 252 | 263 | 41 | 1.54% |

1. Sum of net monthly storage injections/withdrawals.

2. Net LNG Imports line item does not include LNG imports at Baja.

3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

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Energy and Environmental Analysis Inc.

# Expanded Policies Scenario

## Regional Natural Gas Balance (Annual Bcf)

| United States/2,3 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2010-2020 Change | 2010-2020 Annual % Change | 1999-2020 Change | 1999-2020 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Consumption | 25,615 | 25,592 | 26,029 | 26,412 | 27,380 | 27,519 | 27,666 | 28,760 | 28,967 | 29,582 | 4,946 | 1.85% | 7,224 | 1.34% |
| +Storage Injections/1 | 2,287 | 2,430 | 2,415 | 2,446 | 2,428 | 2,591 | 2,493 | 2,687 | 2,626 | 2,663 | 320 | 1.29% | 1,008 | 2.29% |
| + LNG Injections | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 0 | 0.00% | 5 | 0.66% |
| + Pipeline Exports | | | | | | | | | | | | | | |
| + Exports to Canada | 864 | 855 | 865 | 1,132 | 2,320 | 2,343 | 2,470 | 3,091 | 3,103 | 3,114 | 2,208 | 13.15% | 2,575 | 8.71% |
| + Exports to Mexico | 273 | 273 | 255 | 255 | 255 | 255 | 255 | 255 | 255 | 255 | -17 | -0.65% | 200 | 7.62% |
| =Total Demand | 29,080 | 29,192 | 29,607 | 30,288 | 32,426 | 32,750 | 32,925 | 34,834 | 34,993 | 35,656 | 7,458 | 2.37% | 11,012 | 1.77% |
| Total Production | 19,212 | 18,857 | 19,084 | 19,172 | 20,290 | 19,837 | 19,903 | 20,649 | 20,348 | 20,477 | 1,457 | 0.74% | 1,555 | 0.38% |
| + Supplemental Fuels | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 0 | 0.00% | -19 | -1.02% |
| +Storage Withdrawals/1 | 2,357 | 2,573 | 2,289 | 2,464 | 2,303 | 2,705 | 2,516 | 2,513 | 2,765 | 2,640 | 307 | 1.25% | 843 | 1.85% |
| + LNG Withdrawals | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 0 | 0.12% | 4 | 0.47% |
| + Net LNG Imports | 4,060 | 4,437 | 5,045 | 5,410 | 5,593 | 6,242 | 6,596 | 7,290 | 7,670 | 8,319 | 5,026 | 9.71% | 8,220 | 23.44% |
| + Ethane Rejection | 0 | 16 | 13 | 0 | 0 | 1 | 3 | 0 | 0 | 0 | 0 | NA | -7 | -100.00% |
| + Pipeline Imports | | | | | | | | | | | | | | |
| + Imports from Canada | 3,531 | 3,423 | 3,245 | 3,331 | 4,369 | 4,058 | 4,011 | 4,515 | 4,334 | 4,343 | 695 | 1.76% | 488 | 0.57% |
| + Imports from Mexico | 45 | 45 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 34 | 5.45% | 33 | 2.40% |
| --Total Supply | 29,323 | 29,469 | 29,877 | 30,579 | 32,756 | 33,045 | 33,231 | 35,169 | 35,319 | 35,981 | 7,520 | 2.37% | 11,115 | 1.78% |
| Balancing Item | 243 | 277 | 270 | 292 | 331 | 295 | 305 | 335 | 327 | 326 | 62 | 2.15% | 103 | 1.83% |

1. Sum of net monthly storage injections/withdrawals.

2. Net LNG Imports line item does not include LNG imports at Baja.

3. Imports fr[illegible] ie item includes LNG gas delivered to Baja that is export to the U.S.

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# Expanded Policies Scenario

## Gas Prices (Nominal $/MMBtu)

| | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVG | Std Dev |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Henry Hub** | | | | | | | | | | | | | | |
| 1997 | 3.37 | 2.21 | 1.91 | 2.04 | 2.24 | 2.21 | 2.19 | 2.49 | 2.87 | 3.04 | 2.98 | 2.33 | 2.49 | 0.44 |
| 1998 | 2.11 | 2.22 | 2.23 | 2.44 | 2.13 | 2.16 | 2.20 | 1.85 | 1.99 | 1.89 | 2.09 | 1.68 | 2.08 | 0.19 |
| 1999 | 1.84 | 1.77 | 1.80 | 2.13 | 2.26 | 2.30 | 2.29 | 2.79 | 2.57 | 2.70 | 2.31 | 2.36 | 2.26 | 0.32 |
| 2000 | 2.41 | 2.66 | 2.78 | 3.02 | 3.58 | 4.30 | 4.05 | 4.39 | 5.02 | 5.03 | 5.49 | 8.69 | 4.29 | 1.65 |
| 2001 | 8.48 | 5.65 | 5.15 | 5.20 | 4.21 | 3.74 | 3.07 | 3.02 | 2.20 | 2.44 | 2.37 | 2.37 | 3.99 | 1.79 |
| 2002 | 2.32 | 2.28 | 3.02 | 3.39 | 3.52 | 3.22 | 3.04 | 3.13 | 3.55 | 4.13 | 4.06 | 4.74 | 3.37 | 0.68 |
| 2003 | 5.71 | 7.09 | 6.39 | 5.27 | 5.76 | 5.80 | 5.04 | 4.98 | 4.69 | 4.66 | 4.43 | 6.12 | 5.49 | 0.76 |
| 2004 | 6.05 | 5.40 | 5.38 | 4.41 | 5.61 | 5.71 | 7.07 | 6.38 | 5.64 | 4.92 | 5.72 | 5.82 | 5.68 | 0.64 |
| 2005 | 6.98 | 7.23 | 6.79 | 8.85 | 9.12 | 7.52 | 7.39 | 6.97 | 7.86 | 7.38 | 7.52 | 7.68 | 7.61 | 0.68 |
| 2006 | 8.69 | 8.70 | 7.86 | 6.92 | 8.47 | 7.10 | 7.11 | 6.85 | 8.03 | 7.23 | 7.40 | 7.53 | 7.66 | 0.65 |
| 2007 | 8.15 | 7.96 | 7.38 | 6.53 | 6.57 | 5.80 | 6.23 | 6.10 | 6.07 | 4.54 | 5.61 | 5.72 | 6.39 | 0.98 |
| 2008 | 6.22 | 6.15 | 5.63 | 6.31 | 6.77 | 5.86 | 6.43 | 6.18 | 5.79 | 5.08 | 5.72 | 5.84 | 6.00 | 0.42 |
| 2009 | 6.18 | 5.99 | 5.67 | 3.85 | 3.38 | 3.65 | 4.68 | 4.51 | 3.44 | 3.08 | 3.70 | 3.83 | 4.33 | 1.03 |
| 2010 | 4.35 | 4.19 | 3.71 | 6.01 | 6.41 | 5.21 | 4.84 | 4.97 | 5.30 | 4.08 | 4.88 | 4.95 | 4.91 | 0.75 |
| 2011 | 5.43 | 5.22 | 4.78 | 4.26 | 3.17 | 2.74 | 2.99 | 2.87 | 2.74 | 2.49 | 2.83 | 2.99 | 3.54 | 1.02 |
| 2012 | 3.89 | 4.16 | 3.60 | 6.08 | 7.50 | 7.17 | 7.40 | 6.93 | 7.51 | 6.67 | 7.11 | 7.22 | 6.27 | 1.43 |
| 2013 | 7.92 | 7.71 | 7.02 | 4.32 | 3.57 | 3.70 | 4.20 | 3.99 | 3.78 | 3.01 | 3.69 | 3.79 | 4.73 | 1.67 |
| 2014 | 4.77 | 4.83 | 4.28 | 6.50 | 6.77 | 6.14 | 6.29 | 5.80 | 6.30 | 5.87 | 6.02 | 6.15 | 5.81 | 0.74 |
| 2015 | 6.83 | 6.64 | 5.97 | 3 | I4 | 2.27 | 2.57 | 2. 63 | 2. 31 | 2.18 | 2.34 | 2.53 | 3.49 | 1.75 |
| 2016 | 3.43 | 3.58 | 2.93 | 5 | I7 | 6.79 | 7.71 | 7.30 | 6.92 | 5.82 | 6.77 | 6.91 | 5.82 | 1.58 |
| 2017 | 7.78 | 7.83 | 6.95 | 6.35 | 5.90 | 4.93 | 5.00 | 4.85 | 5.58 | 5.21 | 5.29 | 5.39 | 5.92 | 1.03 |
| 2018 | 6.08 | 5.98 | 5.28 | 3.68 | 3.31 | 3.28 | 4.27 | 4.12 | 3.15 | 3.63 | 3.63 | 3.80 | 4.18 | 0.99 |
| 2019 | 4.67 | 4.84 | 4.15 | 6.19 | 6.31 | 6.10 | 6.38 | 5.95 | 6.24 | 5.10 | 5.85 | 6.03 | 5.65 | 0.72 |
| 2020 | 6.74 | 6.76 | 6.04 | 5.62 | 5.87 | 5.24 | 5.50 | 5.09 | 4.68 | 4.34 | 4.77 | 4.98 | 5.47 | 0.74 |

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# Expanded Policies Scenario

Gas Prices (2003$/MMBtu)

| Henry Hub | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVG | Std Dev |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1997 | 3.81 | 2.50 | 2.15 | 2.30 | 2.52 | 2.48 | 2.46 | 2.79 | 3.21 | 3.40 | 3.33 | 2.60 | 2.80 | 0.49 |
| 1998 | 2.35 | 2.47 | 2.48 | 2.72 | 2.36 | 2.40 | 2.44 | 2.04 | 2.20 | 2.09 | 2.31 | 1.86 | 2.31 | 0.22 |
| 1999 | 2.03 | 1.94 | 1.98 | 2.33 | 2.48 | 2.51 | 2.51 | 3.04 | 2.81 | 2.94 | 2.51 | 2.56 | 2.47 | 0.34 |
| 2000 | 2.61 | 2.87 | 3.00 | 3.24 | 3.83 | 4.60 | 4.33 | 4.69 | 5.35 | 5.35 | 5.84 | 9.21 | 4.58 | 1.73 |
| 2001 | 8.97 | 5.97 | 5.43 | 5.47 | 4.42 | 3.92 | 3.22 | 3.16 | 2.29 | 2.54 | 2.46 | 2.46 | 4.19 | 1.91 |
| 2002 | 2.40 | 2.36 | 3.12 | 3.48 | 3.62 | 3.30 | 3.11 | 3.19 | 3.62 | 4.20 | 4.12 | 4.80 | 3.44 | 0.68 |
| 2003 | 5.77 | 7.14 | 6.43 | 5.29 | 5.78 | 5.80 | 5.02 | 4.95 | 4.66 | 4.62 | 4.38 | 6.05 | 5.49 | 0.78 |
| 2004 | 5.96 | 5.31 | 5.28 | 4.32 | 5.48 | 5.57 | 6.88 | 6.20 | 5.47 | 4.76 | 5.53 | 5.61 | 5.53 | 0.62 |
| 2005 | 6.71 | 6.94 | 6.50 | 8.46 | 8.70 | 7.16 | 7.02 | 6.61 | 7.44 | 6.97 | 7.08 | 7.22 | 7.23 | 0.65 |
| 2006 | 8.15 | 8.14 | 7.34 | 6.45 | 7.88 | 6.59 | 6.59 | 6.33 | 7.41 | 6.66 | 6.80 | 6.91 | 7.11 | 0.63 |
| 2007 | 7.46 | 7.27 | 6.73 | 5.94 | 5.96 | 5.26 | 5.64 | 5.51 | 5.47 | 4.08 | 5.03 | 5.12 | 5.79 | 0.93 |
| 2008 | 5.56 | 5.48 | 5.00 | 5.60 | 5.99 | 5.18 | 5.67 | 5.44 | 5.09 | 4.45 | 5.00 | 5.10 | 5.30 | 0.39 |
| 2009 | 5.38 | 5.21 | 4.92 | 3.33 | 2.92 | 3.14 | 4.03 | 3.87 | 2.95 | 2.63 | 3.16 | 3.26 | 3.73 | 0.91 |
| 2010 | 3.70 | 3.56 | 3.14 | 5.08 | 5.40 | 4.38 | 4.06 | 4.16 | 4.43 | 3.41 | 4.06 | 4.11 | 4.12 | 0.63 |
| 2011 | 4.51 | 4.32 | 3.95 | 3.51 | 2.61 | 2.25 | 2.45 | 2.35 | 2.24 | 2.03 | 2.30 | 2.42 | 2.91 | 0.86 |
| 2012 | 3.14 | 3.36 | 2.90 | 4.89 | 6.02 | 5.74 | 5.92 | 5.53 | 5.98 | 5.30 | 5.63 | 5.71 | 5.01 | 1.13 |
| 2013 | 6.25 | 6.08 | 5.52 | 3.39 | 2.79 | 2.89 | 3.27 | 3.10 | 2.93 | 2.33 | 2.86 | 2.92 | 3.70 | 1.33 |
| 2014 | 3.67 | 3.71 | 3.29 | 4.97 | 5.17 | 4.68 | 4.79 | 4.40 | 4.77 | 4.43 | 4.54 | 4.63 | 4.42 | 0.55 |
| 2015 | 5.13 | 4.98 | 4_47 | 2.42 | 1.81 | 1.69 | 1.91 | 1.95 | 1.70 | 1.61 | 1.73 | 1.86 | 2.60 | 1.32 |
| 2016 | 2.51 | 2.62 | 2.14 | 3.83 | 4.70 | 4.93 | 5.58 | 5.27 | 4.99 | 4.19 | 4.86 | 4.95 | 4.21 | 1.12 |
| 2017 | 5.57 | 5.59 | 4.95 | 4.51 | 4.18 | 3.49 | 3.53 | 3.42 | 3.92 | 3.66 | 3.71 | 3.77 | 4.19 | 0.75 |
| 2018 | 4.24 | 4.17 | 3.66 | 2.5[illegible] | | 2.27 | 2.94 | 2.83 | 2.16 | 2.49 | 2.48 | 2.59 | 2.89 | 0.70 |
| 2019 | 3.18 | 3.29 | 2.81 | 4.1[illegible] | | 4.11 | 4.29 | 3.99 | 4.18 | 3.40 | 3.90 | 4.01 | 3.80 | 0.48 |
| 2020 | 4.47 | 4.48 | 3.99 | 3.71 | 3.86 | 3.44 | 3.61 | 3.33 | 3.06 | 2.83 | 3.10 | 3.23 | 3.59 | 0.51 |

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## APPENDIX III

# EXISTING POLICIES SCENARIO

# Existing Policies Scenario

## Regional Natural Gas Consumption (Bcf)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | 1999-2010 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| United States | | | | | | | | | | | | | | | | |
| Total Consumption | 21,990 | 21,363 | 22,359 | 23,270 | 21,548 | 22,419 | 21,497 | 21,996 | 22,094 | 21,978 | 22,540 | 23,170 | 23,577 | 23,961 | 1602 | 0.63% |
| Residential | 4,983 | 4,393 | 4,651 | 4,958 | 4,688 | 4,810 | 5,037 | 5,038 | 5,091 | 5,106 | 5,147 | 5,238 | 5,278 | 5,363 | 711 | 1.30% |
| Commercial | 3,222 | 2,928 | 3,070 | 3,240 | 3,067 | 3,123 | 3,191 | 3,153 | 3,170 | 3,142 | 3,154 | 3,210 | 3,241 | 3,312 | 243 | 0.69% |
| Industrial | 8,904 | 8,828 | 8,944 | 8,828 | 7,496 | 7,995 | 7,196 | 7,253 | 7,033 | 6,548 | 6,670 | 6,775 | 6,795 | 6,713 | -2231 | -2.58% |
| *Cogeneration/1* | *1,481* | *1,474* | *1,492* | *1,471* | *1,179* | *1,249* | *1,116* | *1,124* | *1,092* | *997* | *1,009* | *1,025* | *1,024* | *1,011* | *-481* | *-3.48%* |
| Power Generation | 2,963 | 3,340 | 3,766 | 4,288 | 4,315 | 4,543 | 4,107 | 4,597 | 4,858 | 5,232 | 5,588 | 5,943 | 6,251 | 6,529 | 2763 | 5.13% |
| *Cogeneration/1* | *0* | *0* | *24* | *120* | *280* | *466* | *525* | *600* | *655* | *749* | *821* | *887* | *951* | *1,017* | *993* | *40.75%* |
| Pipeline Fuel | 697 | 662 | 708 | 726 | 737 | 729 | 754 | 747 | 735 | 740 | 764 | 779 | 784 | 807 | 99 | 1.20% |
| Lease & Plant | 1,221 | 1,212 | 1,220 | 1,230 | 1,246 | 1,220 | 1,211 | 1,207 | 1,206 | 1,209 | 1,217 | 1,226 | 1,229 | 1,237 | 17 | 0.13% |
| Cogeneration Total | 1,481 | 1,474 | 1,516 | 1,591 | 1,459 | 1,714 | 1,641 | 1,725 | 1,748 | 1,746 | 1,830 | 1,911 | 1,975 | 2,028 | 512 | 2.68% |

**1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.**

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# Existing Policies Scenario

| | Regional Natural Gas Consumption (Bcf | | | | | | | | | | 2010-2020 | | 1999-2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | Annual % | | Annual % |
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | Change | Change | Change |
| **United States** | | | | | | | | | | | | | | |
| Total Consumption | 24,356 | 24,614 | 24,879 | 25,230 | 25,192 | 25,585 | 25,610 | 25,805 | 25,884 | 26,113 | 2152 | 0.86% | 3754 | 0.74% |
| Residential | 5,431 | 5,503 | 5,514 | 5,553 | 5,598 | 5,675 | 5,703 | 5,758 | 5,816 | 5,899 | 537 | 0.96% | 1248 | 1.14% |
| Commercial | 3,358 | 3,383 | 3,371 | 3,374 | 3,385 | 3,414 | 3,423 | 3,443 | 3,467 | 3,506 | 193 | 0.57% | 436 | 0.63% |
| Industrial | 6,627 | 6,585 | 6,535 | 6,549 | 6,464 | 6,464 | 6,512 | 6,543 | 6,534 | 6,522 | -190 | -0.29% | -2421 | -1.49% |
| *Cogeneration /1* | *998* | *993* | *982* | *982* | *961* | *956* | *962* | *965* | *962* | *956* | *-55* | *-0.56%* | *-536* | *-2.10%* |
| Power Generation | 6,882 | 7,057 | 7,352 | 7,621 | 7,601 | 7,861 | 7,799 | 7,874 | 7,882 | 7,986 | 1456 | 2.03% | 4220 | 3.64% |
| *Cogeneration/1* | *1,096* | *1,149* | *1,214* | *1,270* | *1,279* | *1,329* | *1,332* | *1,351* | *1,364* | *1,388* | *371* | *3.16%* | *1365* | *21.39%* |
| Pipeline Fuel | 811 | 825 | 838 | 856 | 864 | 884 | 886 | 896 | 892 | 903 | 96 | 1.13% | 195 | 1.16% |
| Lease & Plant | 1,247 | 1,262 | 1,270 | 1,277 | 1,281 | 1,287 | 1,287 | 1,290 | 1,292 | 1,297 | 60 | 0.47% | 77 | 0.29% |
| Cogeneration Total | 2,094 | 2,142 | 2,196 | 2,253 | Z240 | Z284 | Z294 | Z317 | Z326 | Z345 | 316 | 1.46% | 828 | 2.10% |

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

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# Existing Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2001-2010 Change | 2001-2010 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total of All Industrial Sectors** | | | | | | | | | | | | |
| Total of All End Uses | 7,545 | 8,005 | 7,197 | 7,255 | 7,035 | 6,549 | 6,672 | 6,777 | 6,796 | 6,715 | -829 | -1.29% |
| Boilers | 2,479 | 2,573 | 2,424 | 2,501 | 2,463 | 2,434 | 2,518 | 2,550 | 2,582 | 2,560 | 81 | 0.36% |
| Process Heat | 2,635 | 2,825 | 2,528 | 2,558 | 2,477 | 2,199 | 2,219 | 2,262 | 2,246 | 2,208 | -427 | -1.95% |
| Other Uses | 1,752 | 1,850 | 1,661 | 1,672 | 1,631 | 1,484 | 1,501 | 1,526 | 1,523 | 1,507 | -245 | -1.66% |
| CogenGasUse/1 | 1,179 | 1,249 | 1,116 | 1,124 | 1,092 | 997 | 1,009 | 1,025 | 1,024 | 1,011 | -168 | -1.69% |
| Ammonia Feedstock | 370 | 426 | 319 | 280 | 235 | 213 | 211 | 21 1 | 21 1 | 2W | -16-" | 6.28% |
| Methanol Feedstock | 157 | 173 | 102 | 78 | 56 | 41 | 40 | 40 | 40 | 35 | -122 | -15.36% |
| Hydrogen Feedstock | 152 | 157 | 162 | 167 | 172 | 177 | 182 | 188 | 193 | 199 | 47 | 3.05% |
| **Food** | | | | | | | | | | | | |
| Total of All End Uses | 599 | 623 | 586 | 585 | 581 | 540 | 545 | 554 | 557 | 559 | -40 | -0.76% |
| Boilers | 223 | 229 | 226 | 229 | 231 | 229 | 234 | 236 | 238 | 238 | 15 | 0.72% |
| Process Heat | 226 | 237 | 214 | 211 | 208 | 184 | 185 | 189 | 189 | 191 | -35 | -1.88% |
| Other Uses | 150 | 158 | 146 | 145 | 142 | 126 | 127 | 129 | 130 | 131 | -19 | -1.53% |
| **Paper** | | | | | | | | | | | | |
| Total of All End Uses | 590 | 595 | [illegible] | 602 | 604 | 585 | 585 | 583 | 576 | 567 | -23 | -0.43% |
| Boilers | 410 | 413 | | 418 | 418 | 413 | 416 | 417 | 417 | 414 | 4 | 0.10% |
| Process Heat | 55 | 55 | - - | 56 | 56 | 52 | 51 | 50 | 48 | 46 | -9 | -1.86% |
| Other Uses | 125 | 126 | 126 | 129 | 130 | 121 | 118 | 116 | 111 | 107 | -18 | -1.71% |
| **Petroleum Refining** | | | | | | | | | | | | |
| Total of All End Uses | 1,351 | 1,414 | 1,308 | 1,274 | 1,234 | 1,096 | 1,095 | 1,110 | 1,112 | 1,109 | -242 | -2.17% |
| Boilers | 354 | 358 | 357 | 362 | 363 | 361 | 365 | 367 | 369 | 367 | 13 | 0.39% |
| Process Heat | 797 | 846 | 759 | 727 | 693 | 584 | 580 | 590 | 591 | 589 | -208 | -3.31% |
| Other Uses | 199 | 211 | 192 | 185 | 178 | 151 | 150 | 152 | 153 | 153 | -47 | -2.92% |

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

# Existing Policies Scenario

**Regional Industrial Natural Gas Consumption (Bcf)**

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2001-2020 Change | Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total of All Industrial Sectors** | | | | | | | | | | | | |
| Total of All End Uses | 6,631 | 6,590 | 6,541 | 6,554 | 6,467 | 6,468 | 6,516 | 6,547 | 6,545 | 6,543 | -1,002 | -0.75% |
| Boilers | 2,541 | 2,540 | 2,555 | 2,571 | 2,580 | 2,603 | 2,623 | 2,645 | 2,660 | 2,681 | 202 | 0.41% |
| Process Heat | 2,160 | 2,130 | 2,079 | 2,072 | 2,003 | 1,982 | 1,994 | 1,993 | 1,975 | 1,953 | -682 | -1.56% |
| Other Uses | 1,490 | 1,481 | 1,462 | 1,463 | 1,430 | 1,423 | 1,432 | 1,436 | 1,430 | 1,421 | -330 | -1.09% |
| Cogen Gas Use /1 | 998 | 993 | 982 | 982 | 961 | 956 | 962 | 965 | 962 | 956 | -223 | -1.10% |
| Ammonia Feedstock | 200 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | -165. | 3.06% |
| Methanol Feedstock | 28 | 24 | 21 | 20 | 18 | 17 | 17 | 16 | 16 | 15 | -142 | -11.64% |
| Hydrogen Feedstock | 205 | 211 | 218 | 224 | 231 | 238 | 245 | 252 | 260 | 268 | 116 | 3.02% |
| **Food** | | | | | | | | | | | | |
| Total of All End Uses | 561 | 562 | 555 | 557 | 549 | 546 | 550 | 551 | 550 | 547 | -52 | -0.48% |
| Boilers | 237 | 239 | 241 | 242 | 245 | 246 | 248 | 251 | 252 | 255 | 32 | 0.70% |
| Process Heat | 192 | 192 | 186 | 186 | 180 | 178 | 179 | 179 | 176 | 174 | -53 | -1.38% |
| Other Uses | 132 | 131 | 128 | 128 | 124 | 122 | 123 | 122 | 121 | 119 | -31 | -1.21% |
| **Paper** | | | | | | | | | | | | |
| Total of All End Uses | 558 | 554 | 550 | 546 | 543 | 541 | 539 | 538 | 536 | 534 | -56 | -0.52% |
| Boilers | 411 | 411 | | 11 | 411 | 411 | 412 | 412 | 412 | 412 | 2 | 0.03% |
| Process Heat | 44 | 43 | | 11 | 40 | 39 | 38 | 38 | 37 | 37 | -18 | -2.08% |
| Other Uses | 103 | 100 | 97 | 95 | 92 | 91 | 89 | 88 | 87 | 85 | -40 | -1.99% |
| **Petroleum Refining** | | | | | | | | | | | | |
| Total of All End Uses | 1,102 | 1,104 | 1,079 | 1,075 | 1,038 | 1,020 | 1,025 | 1,025 | 1,015 | 1,001 | -350 | -1.57% |
| Boilers | 366 | 367 | 369 | 370 | 372 | 373 | 375 | 376 | 377 | 379 | 25 | 0.36% |
| Process Heat | 584 | 585 | 564 | 560 | 530 | 514 | 517 | 515 | 506 | 493 | -304 | -2.50% |
| Other Uses | 151 | 151 | 146 | 145 | 137 | 133 | 134 | 134 | 132 | 129 | -70 | -2.26% |

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

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# Existing Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2001-2010 Change | 2001-2010 %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Chemicals** | | | | | | | | | | | | |
| Total of All End Uses | 2,602 | 2,986 | 2,470 | 2,510 | 2,344 | 2,227 | 2,337 | 2,387 | 2,410 | 2,337 | -264 | -1.18% |
| Boilers | 822 | 910 | 781 | 828 | 781 | 765 | 824 | 842 | 865 | 845 | 23 | 0.31% |
| Process Heat | 549 | 676 | 568 | 605 | 572 | 531 | 560 | 577 | 573 | 543 | -6 | -0.13% |
| Other Uses | 551 | 643 | 538 | 552 | 529 | 500 | 519 | 529 | 527 | 509 | -42 | -0.88% |
| Ammonia Feedstock | 370 | 426 | 319 | 280 | 235 | 213 | 211 | 211 | 211 | 206 | -164 | -6.28% |
| Methanol Feedstock | 157 | 173 | 102 | 78 | 56 | 41 | 40 | 40 | 40 | 35 | -122 | -15.36% |
| Hydrogen Feedstock | 152 | 157 | 162 | 167 | 172 | 177 | 182 | 188 | 193 | 199 | 47 | 3.05% |
| **Stone, Clay and Glass** | | | | | | | | | | | | |
| Total of All End Uses | 349 | 369 | 340 | 344 | 344 | 310 | 313 | 324 | 327 | 332 | -16 | -0.54% |
| Boilers | 17 | 18 | 17 | 18 | 18 | 18 | 19 | 19 | 19 | 20 | 2 | 1.51% |
| Process Heat | 287 | 303 | 278 | 282 | 281 | 252 | 254 | 263 | 266 | 270 | -17 | -0.70% |
| Other Uses | 44 | 47 | 44 | 44 | 45 | 40 | 40 | 42 | 42 | 43 | -1 | -0.37% |
| **Iron and Steel** | | | | | | | | | | | | |
| Total of All End Uses | 318 | 334 | 338 | 368 | 368 | 338 | 330 | 326 | 314 | 303 | -15 | -0.54% |
| Boilers | 50 | 53 | 56 | 60 | 60 | 59 | 60 | 61 | 61 | 60 | 10 | 2.05% |
| Process Heat | 237 | 248 | 248 | 272 | 271 | 245 | 238 | 234 | 223 | 214 | -23 | -1.14% |
| Other Uses | 31 | 33 | 34 | 36 | 37 | 33 | 32 | 32 | 30 | 29 | -2 | -0.73% |
| Primary Aluminum | | | | | | | | | | | | |
| Total of All End Uses | 89 | 85 | 82 | | 80 | 71 | 70 | 71 | 67 | 63 | -26 | -3.81% |
| Boilers | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 0 | 0.11% |
| Process Heat | 73 | 70 | 67 | 66 | 65 | 56 | 55 | 56 | 52 | 49 | -25 | -4.47% |
| Other Uses | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | -2 | -4.26% |
| **Other Primary Metals** | | | | | | | | | | | | |
| Total of All End Uses | 191 | 169 | 137 | 137 | 134 | 117 | 116 | 118 | 118 | 118 | -73 | -5.21% |
| Boilers | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -1 | -2.57% |
| Process Heat | 105 | 93 | 74 | 74 | 72 | 63 | 62 | 63 | 63 | 63 | -42 | -5.49% |
| Other Uses | 81 | 72 | 59 | 58 | 57 | 50 | 50 | 51 | 51 | 51 | -30 | -5.05% |

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# Existing Policies Scenario

**Regional Industrial Natural Gas Consumption (Bcf)**

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2001-2020 Annual Change | 2001-2020 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Chemicals** | | | | | | | | | | | | |
| Total of All End Uses | 2,278 | 2,248 | 2,252 | 2,261 | 2,249 | 2,275 | 2,297 | 2,320 | 2,333 | 2,351 | -250 | -0.53% |
| Boilers | 829 | 818 | 822 | 825 | 820 | 831 | 837 | 844 | 845 | 849 | 27 | 0.17% |
| Process Heat | 517 | 504 | 502 | 503 | 495 | 501 | 507 | 512 | 515 | 519 | -30 | -0.30% |
| Other Uses | 493 | 486 | 484 | 484 | 480 | 483 | 487 | 491 | 493 | 495 | -56 | -0.56% |
| Ammonia Feedstock | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | -165 | -3.06% |
| Methanol Feedstock | 28 | 24 | 21 | 20 | 18 | 17 | 17 | 16 | 16 | 15 | -142 | -11.64% |
| Hydrogen Feedstock | 205 | 211 | 218 | 224 | 231 | 238 | 245 | 252 | 260 | 268 | 116 | 3.02% |
| **Stone, Clay and Glass** | | | | | | | | | | | | |
| Total of All End Uses | 327 | 319 | 312 | 314 | 307 | 307 | 312 | 313 | 313 | 312 | -36 | -0.58% |
| Boilers | 20 | 20 | 20 | 21 | 21 | 22 | 22 | 22 | 23 | 23 | 6 | 1.56% |
| Process Heat | 265 | 257 | 251 | 252 | 247 | 246 | 250 | 251 | 250 | 249 | -38 | -0.74% |
| Other Uses | 42 | 41 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | -4 | -0.54% |
| **Iron and Steel** | | | | | | | | | | | | |
| Total of All End Uses | 294 | 287 | 280 | 276 | 269 | 265 | 263 | 259 | 256 | 252 | -66 | -1.22% |
| Boilers | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 61 | 11 | 1.02% |
| Process Heat | 206 | 200 | 194 | 190 | 184 | 181 | 178 | 175 | 172 | 168 | -69 | -1.78% |
| Other Uses | 28 | 27 | 26 | | 25 | 25 | 24 | 24 | 23 | 23 | -8 | -1.56% |
| **Primary Aluminum** | | | | | | | | | | | | |
| Total of All End Uses | 58 | 54 | 51 | 49 | 46 | 44 | 43 | 42 | 41 | 40 | -50 | -4.19% |
| Boilers | 11 | 11 | 11 | 11 | 10 | 10 | 10 | 10 | 10 | 10 | 0 | -0.17% |
| Process Heat | 44 | 40 | 38 | 36 | 33 | 32 | 31 | 30 | 29 | 27 | -46 | -5.08% |
| Other Uses | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | -3 | -4.95% |
| **Other Primary Metals** | | | | | | | | | | | | |
| Total of All End Uses | 116 | 110 | 104 | 103 | 97 | 95 | 94 | 91 | 89 | 86 | -106 | -4.15% |
| Boilers | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -1 | -1.17% |
| Process Heat | 62 | 59 | 55 | 54 | 51 | 50 | 49 | 48 | 47 | 45 | -60 | -4.39% |
| Other Uses | 50 | 47 | 45 | 44 | 42 | 40 | 40 | 39 | 38 | 36 | -44 | -4.11% |

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# Existing Policies Scenario

## Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2001-2010 Annual Change | 2001-2010 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 869 | 837 | 770 | 765 | 760 | 710 | 718 | 730 | 735 | 741 | -128 | -1.76% |
| Boilers | 358 | 348 | 334 | 340 | 342 | 340 | 346 | 350 | 354 | 355 | -3 | -0.10% |
| Process Heat | 209 | 198 | 174 | 172 | 168 | 149 | 149 | 153 | 153 | 155 | -53 | -3.23% |
| Other Uses | 303 | 290 | 261 | 253 | 249 | 221 | 222 | 227 | 228 | 231 | -72 | -2.96% |
| **Non-Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 587 | 592 | 571 | 588 | 585 | 555 | 563 | 575 | 581 | 586 | -1 | -0.02% |
| Boilers | 228 | 229 | 224 | 231 | 234 | 233 | 238 | 242 | 245 | 246 | 18 | 0.85% |
| Process Heat | 96 | 98 | 92 | 93 | 91 | 64 | 85 | 87 | 88 | 89 | -8 | -0.94% |
| Other Uses | 262 | 265 | 255 | 265 | 260 | 237 | 240 | 245 | 247 | 251 | -11 | -0.48% |
| Industrial Curtailments | 49 | 10 | 1 | 2 | 1 | 0 | 1 | 2 | 1 | 3 | -46 | -26.92% |

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# Existing Policies Scenario

## Regional Industrial Natural Gas Consumption (Bcf)

| U.S. Total | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | 2001-2020 Annual %Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 747 | 756 | 753 | 761 | 755 | 758 | 769 | 776 | 779 | 783 | -86 | -0.55% |
| Boilers | 357 | 361 | 366 | 371 | 377 | 383 | 390 | 397 | 404 | 412 | 54 | 0.75% |
| Process Heat | 157 | 159 | 156 | 157 | 152 | 150 | 152 | 152 | 151 | 149 | -60 | -1.77% |
| Other Uses | 233 | 236 | 231 | 233 | 227 | 224 | 227 | 227 | 225 | 222 | -80 | -1.61% |
| **Non-Manufacturing** | | | | | | | | | | | | |
| Total of All End Uses | 590 | 597 | 606 | 613 | 613 | 615 | 623 | 630 | 634 | 637 | 50 | 0.43% |
| Boilers | 247 | 249 | 252 | 255 | 259 | 262 | 265 | 268 | 272 | 275 | 47 | 0.99% |
| Process Heat | 89 | 90 | 91 | 93 | 92 | 91 | 92 | 93 | 93 | 93 | -4 | -0.22% |
| Other Uses | 254 | 258 | 262 | 265 | 263 | 262 | 266 | 269 | 270 | 269 | 7 | 0.14% |
| Industrial Curtailments | 4 | 5 | 6 | 5 | 3 | 3 | 3 | 4 | 12 | 20 | -46 | -13.18% |

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# Existing Policies Scenario

## Power Generation Capacity (GW)

| LOWER-48 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | 1999-2010 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TOTAL CAPACITY | 723.2 | 727.4 | 736.0 | 763.8 | 799.9 | 865.0 | 920.8 | 927.8 | 935.7 | 951.5 | 956.5 | 961.6 | 965.9 | 972.0 | 236.0 | 2.56% |
| OIL/GAS CAPACITY | 215.1 | 218.9 | 229.1 | 256.4 | 291.4 | 352.6 | 405.0 | 408.8 | 413.5 | 426.0 | 427.9 | 429.8 | 431.7 | 433.6 | 204.5 | 5.97% |
| CT/CC ADDITIONS | 0.0 | 2.1 | 10.5 | 35.9 | 76.6 | 144.2 | 202.7 | 212.6 | 223.3 | 236.1 | 241.0 | 246.0 | 250.9 | 255.8 | 245.4 | 33.73% |
| COAL CAPACITY | 304.5 | 304.5 | 304.5 | 306.4 | 307.2 | 309.6 | 311.9 | 314.3 | 316.7 | 319.0 | 321.4 | 323.7 | 326.4 | 329.1 | 24.6 | 0.71% |
| NUCLEAR CAPACITY | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 96.5 | 95.4 | 95.4 | -1.1 | -0.10% |
| HYDRO CAPACITY | 100.0 | 100.2 | 99.0 | 97.7 | 97.7 | 97.9 | 98.3 | 98.6 | 98.8 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 0.0 | 0.00% |
| OTHER CAPACITY | 7.2 | 7.3 | 6.8 | 6.9 | 7.2 | 8.4 | 9.0 | 9.6 | 10.2 | 10.9 | 11.7 | 12.5 | 13.3 | 14.9 | 8.1 | 7.35% |

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# Existing Policies Scenario

| | Power Generation Capacity (GW) | | | | | | | | | | 2010-2020 | | 1999-2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | Annual % | | Annual % |
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | Change | Change | Change |
| LOWER-48 | | | | | | | | | | | | | | |
| TOTAL CAPACITY | 977.0 | 982.2 | 987.7 | 993.5 | 999.6 | 1013.3 | 1027.4 | 1042.1 | 1056.6 | 1072.5 | 100.5 | 0.99% | 336.5 | 1.81 |
| OIL/GAS CAPACITY | 436.5 | 439.4 | 442.2 | 445.1 | 447.9 | 451.6 | 455.3 | 458.9 | 462.6 | 466.3 | 32.6 | 0.73% | 237.1 | 3.44% |
| *CT/CC ADDITIONS* | *261.8* | *267.7* | *273.5* | *279.4* | *285.3* | *292.1* | *298.8* | *305.5* | *312.1* | *318.9* | *63.0* | *2.23%* | *308.4* | *17.67%* |
| COAL CAPACITY | 329.5 | 329.8 | 330.2 | 330.6 | 331.0 | 337.7 | 344.5 | 351.2 | 357.3 | 364.0 | 35.0 | 1.01% | 59.6 | 0.85% |
| NUCLEAR CAPACITY | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 95.4 | 0.0 | 0.00% | -1.1 | -0.05% |
| HYDRO CAPACITY | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 99.0 | 0.0 | 0.00% | 0.0 | 0.00% |
| OTHER CAPACITY | 16.6 | 18.6 | 20.8 | 23.4 | 26.3 | 29.5 | 33.3 | 37.5 | 42.3 | 47.8 | 32.9 | 12.37% | 40.9 | 9.71% |

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# Existing Policies Scenario

**Power Generation Fossil Fuel Consumption (Quads)**

| LOWER-48 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FOSSIL FUEL CONSUMPTION | 22.5 | 23.7 | 23.8 | 24.779 | 24.662 | 24.675 | 24.446 | 24.955 | 25.602 | 26.180 | 26.754 | 27.458 | 28.049 | 28.700 | 4.9 | 1.73% |
| GAS DEMAND | 3.0 | 3.4 | 3.8 | 4.393 | 4.449 | 4.652 | 4.196 | 4.701 | 4.967 | 5.351 | 5.717 | 6.083 | 6.397 | 6.684 | 2.8 | 5.18% |
| Gas Curtailments | 0.0 | 0.0 | 0.0 | 0.010 | 0.039 | 0.006 | 0.000 | 0.002 | 0.001 | 0.000 | 0.001 | 0.002 | 0.000 | 0.001 | 0.0 | 12.04% |
| Cogen Gas Use /1 | 0.0 | 0.0 | 0.0 | 0.120 | 0.280 | 0.466 | 0.525 | 0.600 | 0.655 | 0.749 | 0.821 | 0.887 | 0.951 | 1.017 | 1.0 | 40.75% |
| COAL DEMAND | 18.7 | 19.1 | 19.0 | 19.491 | 19.235 | 19.537 | 19.719 | 20.011 | 20.339 | 20.492 | 20.714 | 20.982 | 21.219 | 21.496 | 2.5 | 1.13% |
| OIL DEMAND | 0.8 | 1.2 | 1.0 | 0.895 | 0.978 | 0.487 | 0.531 | 0.243 | 0.296 | 0.336 | 0.323 | 0.393 | 0.432 | 0.519 | -0.4 | -5.35% |

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

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# Existing Policies Scenario

| | Power Generation Fossil Fuel Consumption (Quads) | | | | | | | | | | 2010-2020 | | 1999-2020 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | Annual % Change | Change | Annual % Change |
| **LOWER-48** | | | | | | | | | | | | | | |
| FOSSIL FUEL CONSUMPTION | 29.375 | 30.018 | 30.516 | 31.093 | 31.669 | 32.386 | 32.963 | 33.630 | 34.278 | 35.059 | 6.4 | 2.02% | 11.283 | 1.87% |
| GAS DEMAND | 7.048 | 7.229 | 7.533 | 7.809 | 7.783 | 8.049 | 7.984 | 8.060 | 8.076 | 8.192 | 1.5 | 2.05% | 4.355 | 3.68% |
| Gas Curtailments | 0.002 | 0.005 | 0.006 | 0.006 | 0.003 | 0.003 | 0.003 | 0.003 | 0.013 | 0.023 | 0.0 | 33.09% | 0.023 | 21.61% |
| Cogen Gas Use /1 | 1.096 | 1.149 | 1.214 | 1.270 | 1.279 | 1.329 | 1.332 | 1.351 | 1.364 | 1.388 | 0.4 | 3.16% | 1.365 | 21.39% |
| COAL DEMAND | 21.728 | 21.858 | 21.950 | 21.960 | 22.037 | 22.351 | 22.727 | 23.162 | 23.575 | 24.067 | 2.6 | 1.14% | 5.077 | 1.13% |
| OIL DEMAND | 0.600 | 0.931 | 1.032 | 1.324 | 1.848 | 1.986 | 2.253 | 2.407 | 2.627 | 2.801 | 2.3 | 18.36% | 1.851 | 5.28% |

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.
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# Existing Policies Scenario

## Regional Natural Gas Balance (Annual Bcf)

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 1999-2010 Change | 1999-2010 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **United States/2,3** | | | | | | | | | | | | | | | | |
| Total Consumption | 21,990 | 21,363 | 22,358 | 23,269 | 21,547 | 22,417 | 21,495 | 21,993 | 22,091 | 21,975 | 22,538 | 23,168 | 23,575 | 23,959 | 1,601 | 0.63% |
| +Storage Injections/1 | 1,886 | 1,993 | 1,656 | 1,533 | 2,380 | 1,637 | 2,406 | 2,045 | 2,102 | 2,318 | 2,291 | 2,244 | 2,287 | 2,241 | 586 | 2.79% |
| + LNG Injections | 76 | 58 | 37 | 56 | 35 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 5 | 1.27% |
| + Pipeline Exports | | | | | | | | | | | | | | | | |
| + Exports to Canada | 529 | 435 | 539 | 581 | 789 | 735 | 883 | 819 | 784 | 810 | 832 | 872 | 892 | 910 | 371 | 4.87% |
| + Exports to Mexico | 33 | 48 | 55 | 100 | 140 | 266 | 340 | 409 | 512 | 461 | 212 | 240 | 240 | 272 | 218 | 15.73% |
| =Total Demand | 24,513 | 23,896 | 24,644 | 25,540 | 24,893 | 25,098 | 25,165 | 25,309 | 25,531 | 25,605 | 25,915 | 26,567 | 27,035 | 27,424 | 2,781 | 0.98% |
| Total Production | 19,207 | 18,862 | 18,922 | 19,088 | 19,383 | 18,734 | 18,528 | 18,415 | 18,389 | 18,512 | 18,795 | 18,969 | 19,052 | 19,201 | 279 | 0.13% |
| + Supplemental Fuels | 103 | 102 | 98 | 86 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | -19 | -1.94% |
| + Storage Withdrawals/1 | 1,919 | 1,470 | 1,797 | 2,380 | 1,231 | 2,080 | 2,211 | 2,328 | 2,391 | 2,047 | 2,025 | 2,249 | 2,203 | 2,325 | 528 | 2.37% |
| +LNGWithdrawals | 68 | 52 | 36 | 51 | 35 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 3 | 0.80% |
| + Net LNG Imports | 16 | 20 | 100 | 160 | 169 | 164 | 464 | 807 | 1,047 | 1,487 | 1,578 | 1,765 | 1,870 | 1,870 | 1,770 | 30.52% |
| + Ethane Rejection | 5 | 39 | 7 | 0 | 102 | 0 | 87 | 5 | 0 | 23 | 17 | 11 | 6 | 62 | 55 | 21.93% |
| + Pipeline Imports | | | | | | | | | | | | | | | | |
| + Imports from Canada | 3,494 | 3,577 | 3,856 | 3,997 | 4,261 | 4,227 | 4,087 | 3,918 | 3,835 | 3,692 | 3,580 | 3,661 | 3,996 | 4,086 | 230 | 0.53% |
| + Imports from Mexico | 11 | 10 | 50 | 6 | 7 | 0 | 0 | 0 | 0 | 9 | 73 | 53 | 60 | 49 | -2 | -0.29% |
| =Total Supply | 24,822 | 24,131 | 24,866 | 25,769 | 25,266 | 25,324 | 25,496 | 25,592 | 25,781 | 25,889 | 26,186 | 26,827 | 27,306 | 27,711 | 2,844 | 0.99% |
| Balancing Item | 309 | 236 | 222 | 229 | 374 | 226 | 331 | 283 | 249 | 283 | 270 | 260 | 271 | 286 | 64 | 2.32% |

1. Sum of net monthly storage injections/withdrawals.
2. Net LNG Imports line item does not include LNG imports at Baja.
3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

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# Existing Policies Scenario

**Regional Natural Gas Balance (Annual Bcf)**

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Change | 2010-2020 Annual % Change | Change | 1999-2020 Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **United States/2,3** | | | | | | | | | | | | | | |
| Total Consumption | 24,354 | 24,612 | 24,877 | 25,228 | 25,190 | 25,583 | 25,608 | 25,803 | 25,882 | 26,111 | 2,152 | 0.86% | 3,753 | 0.74% |
| + Storage Injections/1 | 2,233 | 2,371 | 2,278 | 2,307 | 2,400 | 2,339 | 2,402 | 2,368 | 2,429 | 2,434 | 193 | 0.83% | 779 | 1.85% |
| + LNG Injections | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 0 | 0.00% | 5 | 0.66% |
| + Pipeline Exports | | | | | | | | | | | | | | |
| + Exports to Canada | 903 | 895 | 913 | 920 | 918 | 923 | 928 | 948 | 926 | 925 | 16 | 0.17% | 386 | 2.61% |
| + Exports to Mexico | 273 | 273 | 255 | 255 | 255 | 255 | 255 | 255 | 255 | 255 | -17 | -0.65% | 200 | 7.62% |
| =Total Demand | 27,805 | 28,194 | 28,366 | 28,752 | 28,805 | 29,142 | 29,236 | 29,415 | 29,533 | 29,768 | 2,343 | 0.82% | 5,124 | 0.90% |
| Total Production | 19,414 | 19,717 | 19,882 | 20,049 | 20,152 | 20,271 | 20,294 | 20,366 | 20,418 | 20,528 | 1,327 | 0.67% | 1,606 | 0.39% |
| + Supplemental Fuels | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 0 | 0.00% | -19 | -1.02% |
| + Storage Withdrawals/1 | 2,356 | 2,311 | 2,282 | 2,323 | 2,297 | 2,333 | 2,360 | 2,372 | 2,435 | 2,497 | 172 | 0.72% | 700 | 1.58% |
| + LNG Withdrawals | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 0 | 0.12% | 4 | 0.47% |
| + Net LNG Imports | 1,870 | 1,875 | 1,870 | 1,870 | 1,870 | 1,875 | 1,870 | 1,870 | 1,870 | 1,875 | 5 | 0.03% | 1,775 | 14.99% |
| + Ethane Rejection | 109 | 170 | 187 | 214 | 270 | 270 | 291 | 309 | 347 | 372 | 310 | 19.67% | 365 | 20.85% |
| + Pipeline Imports | | | | | | | | | | | | | | |
| + Imports from Canada | 4,207 | 4,324 | 4,346 | 4,512 | 4,534 | 4,663 | 4,713 | 4,787 | 4,805 | 4,869 | 783 | 1.77% | 1,013 | 1.12% |
| + Imports from Mexico | 45 | 45 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 34 | 5.45% | 33 | 2.40% |
| =Total Supply | 28,119 | 28,560 | 28,768 | 29,169 | 29,324 | 29,615 | 29,730 | 29,906 | 30,076 | 30,343 | 2,632 | 0.91% | 5,476 | 0.95% |
| Balancing Item | 314 | 366 | 403 | 417 | 519 | 473 | 495 | 491 | 543 | 575 | 289 | 7.23% | 353 | 4.63% |

1. Sum of net monthly storage injections/withdrawals.
2. Net LNG Imports line item does not include LNG imports at Baja.
3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

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# Existing Policies Scenario

Gas Prices (Nominal $/MMBtu)

| Henry Hub | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVG | Std Dev |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1997 | 3.37 | 2.21 | 1.91 | 2.04 | 2.24 | 2.21 | 2.19 | 2.49 | 2.87 | 3.04 | 2.98 | 2.33 | 2.49 | 0.44 |
| 1998 | 2.11 | 2.22 | 2.23 | 2.44 | 2.13 | 2.16 | 2.20 | 1.85 | 1.99 | 1.89 | 2.09 | 1.68 | 2.08 | 0.19 |
| 1999 | 1.84 | 1.77 | 1.80 | 2.13 | 2.26 | 2.30 | 2.29 | 2.79 | 2.57 | 2.70 | 2.31 | 2.36 | 2.26 | 0.32 |
| 2000 | 2.41 | 2.66 | 2.78 | 3.02 | 3.58 | 4.30 | 4.05 | 4.39 | 5.02 | 5.03 | 5.49 | 8.69 | 4.29 | 1.65 |
| 2001 | 8.48 | 5.65 | 5.15 | 5.20 | 4.21 | 3.74 | 3.07 | 3.02 | 2.20 | 2.44 | 2.37 | 2.37 | 3.99 | 1.79 |
| 2002 | 2.32 | 2.28 | 3.02 | 3.39 | 3.52 | 3.22 | 3.04 | 3.13 | 3.55 | 4.13 | 4.06 | 4.74 | 3.37 | 0.68 |
| 2003 | 5.71 | 7.09 | 6.39 | 5.27 | 5.76 | 5.80 | 5.04 | 4.98 | 4.69 | 4.66 | 4.43 | 6.12 | 5.49 | 0.76 |
| 2004 | 6.05 | 5.40 | 5.38 | 4.42 | 5.62 | 5.73 | 7.08 | 6.38 | 5.68 | 4.95 | 5.75 | 5.85 | 5.69 | 0.64 |
| 2005 | 7.02 | 7.29 | 6.86 | 8.92 | 9.16 | 7.62 | 7.48 | 7.07 | 8.02 | 7.52 | 7.67 | 7.86 | 7.71 | 0.68 |
| 2006 | 8.93 | 9.02 | 8.20 | 7.34 | 9.04 | 7.81 | 7.76 | 7.48 | 8.59 | 7.66 | 7.93 | 8.07 | 8.15 | 0.58 |
| 2007 | 8.69 | 8.48 | 7.92 | 6.30 | 6.28 | 5.88 | 6.36 | 6.29 | 6.14 | 4.51 | 5.70 | 5.80 | 6.53 | 1.17 |
| 2008 | 6.38 | 6.34 | 5.78 | 7.15 | 7.65 | 6.97 | 7.48 | 7.23 | 6.97 | 5.85 | 6.72 | 6.84 | 6.78 | 0.57 |
| 2009 | 7.38 | 7.20 | 6.70 | 6.12 | 5.94 | 5.94 | 6.60 | 6.44 | 6.38 | 5.40 | 6.14 | 6.23 | 6.37 | 0.52 |
| 2010 | 6.83 | 6.69 | 6.15 | 8.29 | 9.01 | 7.96 | 7.70 | 7.75 | 8.42 | 6.59 | 7.49 | 7.74 | 7.55 | 0.81 |
| 2011 | 8.40 | 8.33 | 7.71 | 8.75 | 8.73 | 8.10 | 8.50 | 8.24 | 8.76 | 7.51 | 8.24 | 8.35 | 8.30 | 0.37 |
| 2012 | 9.14 | 9.23 | 8.54 | 8.61 | 9.92 | 9.71 | 9.81 | 9.66 | 9.83 | 9.29 | 9.61 | 9.74 | 9.43 | 0.45 |
| 2013 | 10.32 | 10.23 | 9.64 | 9.49 | 9.74 | 9.75 | 9.92 | 9.84 | 9.86 | 8.50 | 9.41 | 9.58 | 9.69 | 0.44 |
| 2014 | 10.19 | 10.17 | 9.69 | 10.41 | 10.91 | 10.21 | 10.24 | 10.25 | 10.58 | 10.31 | 10.37 | 10.54 | 10.32 | 0.28 |
| 2015 | 11.15 | 11.21 | 10.60 | 11.15 | 12.00 | 11.47 | 11.58 | 11.32 | 11.83 | 10.83 | 11.11 | 11.47 | 11.31 | 0.38 |
| 2016 | 11.86 | 11.95 | 11.35 | 11.17 | 11.79 | 11.36 | 11.54 | 11.28 | 11.25 | 10.53 | 11.04 | 11.18 | 11.36 | 0.38 |
| 2017 | 11.77 | 11.78 | 11.16 | | 2.95 | 12.01 | 12.22 | 11.77 | 12.17 | 11.19 | 11.71 | 11.84 | 11.91 | 0.47 |
| 2018 | 12.38 | 12.40 | 11.79 | | 3.32 | 12.61 | 13.11 | 12.18 | 12.35 | 11.67 | 12.07 | 12.20 | 12.32 | 0.49 |
| 2019 | 12.81 | 12.87 | 12.25 | [illegible] | 4.29 | 13.64 | 13.65 | 12.70 | 13.71 | 12.08 | 12.86 | 12.98 | 13.15 | 0.66 |
| 2020 | 13.61 | 13.76 | 13.11 | 14.09 | 15.02 | 14.07 | 14.29 | 13.15 | 14.10 | 12.96 | 13.41 | 13.57 | 13.76 | 0.56 |

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# Existing Policies Scenario

Gas Prices (2003$/MMBtu)

| Henry Hub | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVG | Std Dev |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1997 | 3.81 | 2.50 | 2.15 | 2.30 | 2.52 | 2.48 | 2.46 | 2.79 | 3.21 | 3.40 | 3.33 | 2.60 | 2.80 | 0.49 |
| 1998 | 2.35 | 2.47 | 2.48 | 2.72 | 2.36 | 2.40 | 2.44 | 2.04 | 2.20 | 2.09 | 2.31 | 1.86 | 2.31 | 0.22 |
| 1999 | 2.03 | 1.94 | 1.98 | 2.33 | 2.48 | 2.51 | 2.51 | 3.04 | 2.81 | 2.94 | 2.51 | 2.56 | 2.47 | 0.34 |
| 2000 | 2.61 | 2.87 | 3.00 | 3.24 | 3.83 | 4.60 | 4.33 | 4.69 | 5.35 | 5.35 | 5.84 | 9.21 | 4.58 | 1.73 |
| 2001 | 8.97 | 5.97 | 5.43 | 5.47 | 4.42 | 3.92 | 3.22 | 3.16 | 2.29 | 2.54 | 2.46 | 2.46 | 4.19 | 1.91 |
| 2002 | 2.40 | 2.36 | 3.12 | 3.48 | 3.62 | 3.30 | 3.11 | 3.19 | 3.62 | 4.20 | 4.12 | 4.80 | 3.44 | 0.68 |
| 2003 | 5.77 | 7.14 | 6.43 | 5.29 | 5.78 | 5.80 | 5.02 | 4.95 | 4.66 | 4.62 | 4.38 | 6.05 | 5.49 | 0.78 |
| 2004 | 5.96 | 5.31 | 5.28 | 4.33 | 5.49 | 5.59 | 6.89 | 6.20 | 5.51 | 4.79 | 5.55 | 5.64 | 5.55 | 0.62 |
| 2005 | 6.75 | 6.99 | 6.57 | 8.52 | 8.74 | 7.25 | 7.10 | 6.71 | 7.59 | 7.10 | 7.23 | 7.39 | 7.33 | 0.65 |
| 2006 | 8.37 | 8.44 | 7.67 | 6.84 | 8.41 | 7.26 | 7.19 | 6.91 | 7.93 | 7.06 | 7.29 | 7.40 | 7.56 | 0.56 |
| 2007 | 7.95 | 7.75 | 7.22 | 5.73 | 5.70 | 5.33 | 5.75 | 5.67 | 5.53 | 4.05 | 5.11 | 5.19 | 5.92 | 1.10 |
| 2008 | 5.70 | 5.65 | 5.14 | 6.34 | 6.77 | 6.16 | 6.60 | 6.36 | 6.13 | 5.13 | 5.88 | 5.98 | 5.99 | 0.50 |
| 2009 | 6.43 | 6.26 | 5.81 | 5.30 | 5.14 | 5.12 | 5.68 | 5.53 | 5.46 | 4.62 | 5.24 | 5.31 | 5.49 | 0.48 |
| 2010 | 5.81 | 5.67 | 5.21 | 7.00 | 7.59 | 6.70 | 6.46 | 6.49 | 7.04 | 5.50 | 6.24 | 6.43 | 6.34 | 0.67 |
| 2011 | 6.96 | 6.90 | 6.37 | 7.21 | 7.18 | 6.65 | 6.97 | 6.74 | 7.14 | 6.11 | 6.70 | 6.77 | 6.81 | 0.32 |
| 2012 | 7.39 | 7.45 | 6.88 | 6.93 | 7.96 | 7.78 | 7.84 | 7.70 | 7.82 | 7.38 | 7.62 | 7.71 | 7.54 | 0.33 |
| 2013 | 8.15 | 8.06 | 7.58 | 7.45 | 7.62 | 7.62 | 7.73 | 7.66 | 7.66 | 6.59 | 7.27 | 7.39 | 7.56 | 0.38 |
| 2014 | 7.85 | 7.81 | 7.43 | 7.9[illegible] | [illegible] | 7.78 | 7.79 | 7.78 | 8.01 | 7.79 | 7.82 | 7.93 | 7.86 | 0.20 |
| 2015 | 8.38 | 8.40 | 7.93 | 8.3[illegible] | | 8.53 | 8.59 | 8.38 | 8.74 | 7.98 | 8.17 | 8.43 | 8.40 | 0.28 |
| 2016 | 8.69 | 8.74 | 8.29 | 8.1[illegible] | | 8.24 | 8.36 | 8.15 | 8.11 | 7.58 | 7.93 | 8.01 | 8.23 | 0.32 |
| 2017 | 8.41 | 8.41 | 7.95 | 8.78 | 9.19 | 8.50 | 8.63 | 8.30 | 8.56 | 7.86 | 8.20 | 8.28 | 8.42 | 0.34 |
| 2018 | 8.64 | 8.63 | 8.19 | 8.16 | 9.22 | 8.71 | 9.04 | 8.37 | 8.48 | 7.99 | 8.25 | 8.32 | 8.50 | 0.35 |
| 2019 | 8.72 | 8.74 | 8.30 | 9.43 | 9.64 | 9.19 | 9.17 | 8.52 | 9.18 | 8.07 | 8.58 | 8.64 | 8.85 | 0.45 |
| 2020 | 9.04 | 9.12 | 8.67 | 9.29 | 9.89 | 9.24 | 9.37 | 8.61 | 9.21 | 8.45 | 8.72 | 8.81 | 9.03 | 0.39 |

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