Meeting the Gas Supply Challenge of the Next 20 Years

Non-Traditional Gas Sources

Prepared for

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NON-TRADITIONAL GAS SOURCES

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Introduction

A U.S. gas market of 30 Tcf or more has become a strategic context for discussions about future growth in gas sales. Some market analyses, such as the American Gas Foundation's *Fueling the Future*, see a gas market that could grow to 33 Tcf annually in the U.S. if significant developments occur with respect to national energy policy. Almost all (> 98%) of this consumption will be in the lower-48 gas markets.

Currently, 99% of U.S. gas supply comes from the lower-48 United States or Canada. While lower-48 and Canadian gas production could grow in the future, the extent to which this growth can occur is uncertain, particularly if gas is to be competitively priced as a fuel of choice. This uncertainty is expected to grow over the long term. As a result, *non-traditional gas sources*, such as LNG imports or deliveries from Alaska to the lower-48, are *expected to play a growing role in the U.S. gas supply picture*.

The non-traditional gas supply sources discussed in this report are Alaska, LNG, Mexico, Hydrates, and gas-to-liquids (GTL). They have played a minor role in lower-48 gas supply to date. In fact, *Mexico has been a net consumer of lower-48 gas supply since the mid-1980s*. In 2001, lower-48 gas consumption was 21.0 Tcf (57.6 Bcf/d), but only 108 Bcf (0.5%) of the gas supply to meet this demand came from non-traditional sources. In the future, non-traditional sources will play a growing role in lower-48 gas supply. Past 2015, non-traditional sources may provide most or all of the growth in lower-48 gas supply.

Alaska

Current Alaska gas production and markets can be divided into South Alaska Cook Inlet and North Slope. More than half of the *marketed* gas production in Alaska is in North Alaska. While each area has different drivers, reserves levels, and prospects, they may become linked over the next 20 years.

- *Production prospects in the South Alaska are uncertain.* Resource estimates suggest that Cook Inlet gas production has peaked, and may begin to decline in the near-term. The critical uncertainty for South Alaska production is coalbed methane gas production. If coalbed methane production can develop in the near term, than Cook Inlet gas production could be sustained at current levels and might even grow.

- *Over the first six months of 2002, North Alaska gas production is on a pace to exceed 3.4 Tcf (9.4 Bcf/d), a new record.* However, 92% of that gas production was re-injected. Because regulations prohibit flaring of gas from producing reservoirs, gas that cannot be consumed in North Alaska must be re-injected, or the oil cannot be produced. The re-injected gas has helped to maintain reservoir pressure, thus increasing oil recovery.

- *The Prudhoe Bay reservoir is at an operational point where marketing of the produced gas may be very attractive to the owners.* Currently, the cost of producing and re-injecting gas is covered by oil revenues, but declining oil production is increasing the burden on unit oil production costs. If incremental gas sales could be developed, the added gas revenues would reduce the burden of production costs on oil, thus improving oil economics.

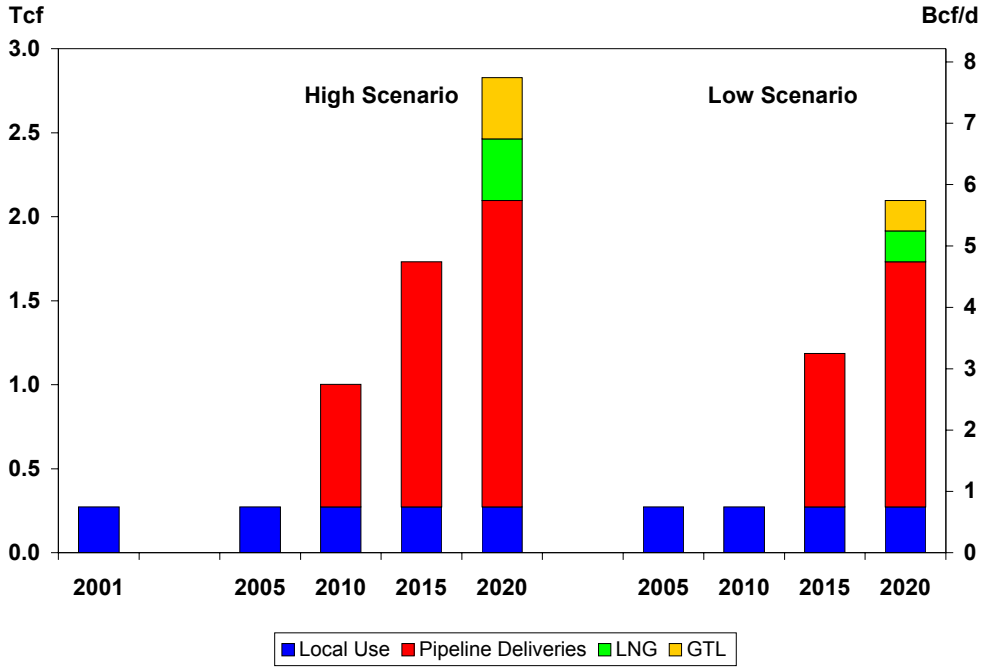
- *North Alaska ultimate gas resource estimates have more than doubled since 1979, and most recently, are almost 200 Tcf.* Based on assessments of specific North Alaska areas (National Petroleum Resource – Alaska, 1002 part of Alaska National Wildlife Refuge) and sediment yields, the ultimate resource estimate should grow substantially. Therefore, *North Alaska marketed gas production could grow substantially, possibly peaking well above 10 Bcf/d.* The critical question is whether such a large production potential or its products can be delivered to market.

- *If* ***marketed*** *Alaska gas is to grow substantially, the markets for that gas will be outside Alaska. There are four principal options to move North Alaska gas or its products 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 final option is to convert North Alaska gas to liquids via gas-to-liquids (GTL) technology in either North Alaska or South Alaska.

- ***Marketed*** *Alaska gas production could be on the verge of a significant growth that might begin as early as 2010.* Although Alaska gas production could grow substantially*, a large part of this growth may not be delivered to North American gas markets*. The significant advances in GTL technology suggest that a large share of Alaska gas production may be converted into liquids. If LNG terminals are constructed in South Alaska, a noticeable share of that LNG may find its way to North Asia or perhaps Mexican gas markets. Therefore, the *greater uncertainty* surrounding Alaska gas prospects through 2020 may be *where Alaska gas is marketed*.

Figure 1.1 allocates *marketed* North Alaska gas production to pipeline deliveries to Western Canada, GTL, and LNG. In the **High Scenario**, pipeline deliveries to the lower-48 begin in 2010, but LNG exports and GTL conversions do not develop until after 2015. By 2020, North Alaska gas production grows to 7.9 Bcf/d, but only 5 Bcf/d is delivered by pipeline to Western Canada and then on to the lower-48. Two Bcf/d is converted into LNG or liquids for delivery to market.

Figure 1.1
North Alaska Gas Market Scenarios



In the **Low Scenario**, pipeline deliveries to the lower-48 begin after 2010, and LNG exports and GTL conversions do not develop until after 2015. By 2020, North Alaska gas production reaches 5.8 Bcf/d, but pipeline deliveries only reach 4 Bcf/d. One Bcf/d is converted into LNG or liquids for delivery to market.

LNG

The LNG share of U.S. gas supply is expected to grow substantially, because U.S. gas demand is expected to grow faster than U.S. gas production. Some projections of this "gap" between U.S. gas demand and production are almost 10 Bcf/d in 2010 and could exceed 15 Bcf/d in 2015. As a result, more than 25 new LNG terminal projects with scheduled operation dates before 2010 are under consideration in the United States, Canada, or Mexico.

LNG costs have declined substantially in the last decade, improving the competitive attractiveness of LNG in the U.S. gas market, and could decline up to an additional 25% for liquefaction facilities. Given the likely decline in LNG facility costs over the next 20 years, *delivered LNG prices in the*

United States are not likely to show much growth and may even decline unless some gas equivalent of OPEC develops *during the next 20 years*.

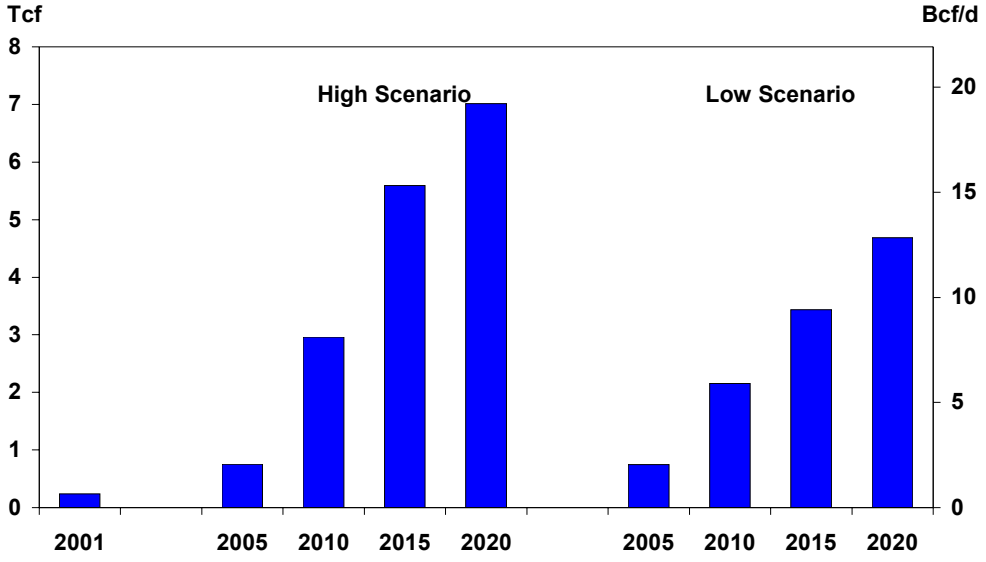
- *LNG deliveries to U.S. terminals from Atlantic Basin, Mediterranean, and Pacific sources appear economically attractive at current costs.* Deliveries from the Middle East have uncertain economics, but might be attractive should LNG costs continue to decline.

- *While long-term growth prospects for U.S. LNG imports are strong, near-term growth (through 2005) is likely to be relatively modest.* The modest, near-term growth prospects in U.S. LNG imports reflect strong competition from Western Europe gas markets for access to Atlantic Basin and Mediterranean gas liquefaction capacity. This competition could be strong through 2010, particularly if the average, annual growth in Western Europe LNG imports picks up from historical trends.

- U.S. LNG imports are likely to grow substantially in the coming years, and may provide up to 20% of U.S. gas supply by 2020. This large growth in LNG imports will probably result in LNG becoming the marginal source of U.S. gas supplies. Thus, *U.S. gas prices would increasingly be set by world gas prices*, much in the same way that U.S. oil prices are currently set by the world oil prices.

Figure 1.2 presents the outlook for LNG imports into the United States. U.S. LNG imports include LNG delivered to Baja California and Bahamas terminals. In the **High LNG Import Scenario**, LNG imports reach 750 Bcf (2.1 Bcf/d) in 2005, and grow to 3.0 Tcf (8.1 Bcf/d) by 2010. Growth after 2010 averages more than 1 Bcf/d per year. By 2020, LNG imports reach 7.0 Tcf (19.2 Bcf/d.

Figure 1.2
U.S. LNG Imports



In the **Low LNG Import Scenario**, LNG imports reach 750 Bcf (2.1 Bcf/d) in 2005, and grow to 2.2 Tcf (5.9 Bcf/d) by 2010. Growth after 2010 averages 0.7 Bcf/d per year. By 2010, LNG imports reach 4.7 Tcf (12.8 Bcf/d), utilizing 85% of available LNG terminal capacity.

U.S. - Mexico Gas Trade

The direction and size of U.S.-Mexico gas trade has varied substantially. U.S. imports of gas from Mexico averaged more than 100 Bcf/year in 1981-82, and Mexico was viewed as a significant future source of natural gas to the United States. After 1982, trade almost disappeared, and when it began to recover, the United States was exporting gas to Mexico. Since the mid-1990s, U.S. gas exports have grown substantially, setting new records in 2000 and 2001. U.S. gas exports in 2002 are on a pace to exceed 160 Bcf for the year, another new record.

- *Mexican gas demand is expected to grow 300-500 MMcf/d or more through 2020.* Most of the growth will be to generate electricity. By 2020, Mexican gas demand could reach 4.9 Tcf (13.4 Bcf/d) by 2020, almost four times its 1.3 Tcf in 2001. Based on long-term historical trends, however, gas demand might reach 3.4 Tcf (9.2 Bcf/d) by 2020.

- *Unless a world-scale gas field, play, or basin beyond current Pemex expectations is discovered in Mexico, the rapid growth in Mexican gas demand will need growing gas deliveries from outside Mexico.* In the near term, the increased demand for imports will be met *solely* by increased deliveries from U.S. gas supply sources. By 2005, U.S. gas exports to Mexico are likely to exceed 1 Bcf/d. If U.S. gas supplies remain tight in the near-term, this increased gas demand from Mexico would put upward pressures on U.S. gas prices.

- *With the opening of new LNG terminals in Mexico after 2005, the growth in Mexican demand for U.S. gas supply will begin to tail off.* Before 2010, Mexican demand for U.S. gas supply will begin to decline.

- *After 2010, net annual imports of gas by Mexico from the United States will probably end.* In fact, some modest gas volumes (net annual basis) may begin to flow back from Northeast Mexico into Texas.

Hydrates

- While the hydrate resource dwarfs traditional gas resources in North America, *significant U.S. hydrate production is unlikely to develop until after 2020* because of its current technological status. Most of the accessible (not subject to land restrictions) hydrate resource is located in North Alaska. Given the substantial and growing expectations of ultimate gas resource potential in North Alaska and the technological hurdles facing hydrate development, substantial hydrate production in North Alaska is unlikely to develop until production from traditional resources has peaked, which will probably be well after 2020.

- *A substantial hydrate resource potential also exists in the Western Gulf of Mexico, and this would also be accessible.* Because traditional gas production in the Gulf of Mexico is near its peak, noticeable progress in hydrate production technology might occur in the Western Gulf of Mexico before anywhere else in North America. More important, hydrate production in the Gulf of Mexico would receive a higher price than production in Alaska.

GTL

- Interest in GTL development has surged substantially in the last decade. Technology advances have allowed *GTL technology to be competitive* at current oil prices but with *gas feedstock prices well above the often-cited 50-75 ¢/MMBtu*. As a result, a significant number of commercial-scale GTL facilities will probably begin operation by 2010. After 2010, GTL expansion could begin to surge, and GTL would become a growing market for "stranded" gas.

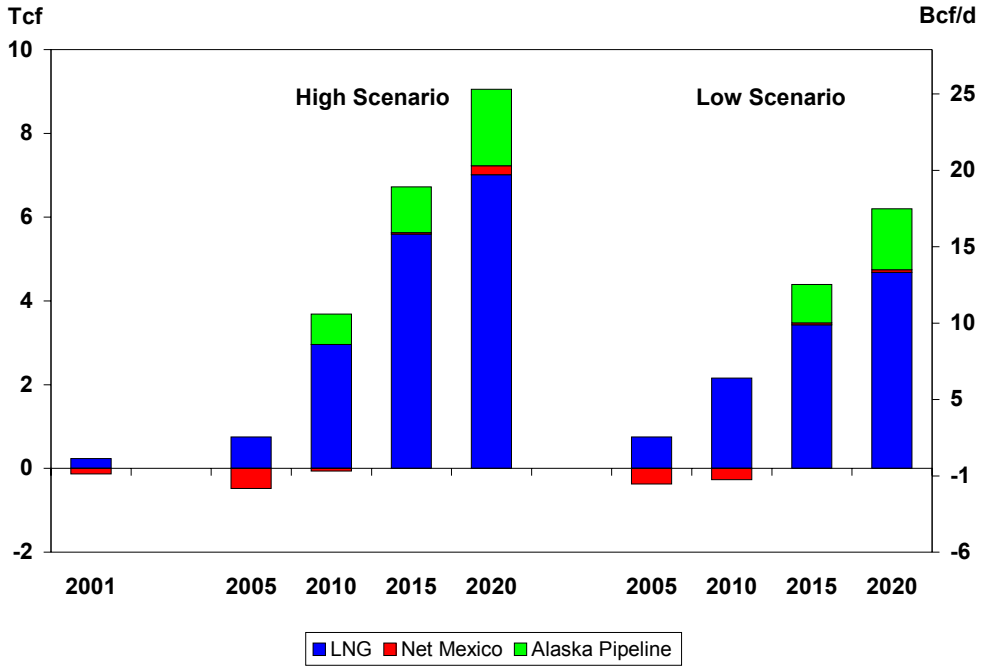
- "Stranded" gas, however, is also the principal gas source for the expected surge in global LNG supply during the next 20 years. As a result, *GTL may compete with LNG as a market for "stranded" gas reserves.*

Deliveries to Lower-48 Gas Markets

Supply from non-traditional sources are not necessarily additive. Some LNG delivered to lower-48 gas markets may come from Alaska, and some of the growth in North Alaska gas production may not even be delivered to North American gas markets. Instead, it may go to North Asia or Mexico as LNG or be converted into liquids via GTL technology. Mexico will be a consumer of lower-48 gas supply for about a decade, but then may become a source of lower-48 gas supply.

Figure 1.3 presents the outlook for gas deliveries to lower-48 gas markets from non-traditional gas sources for a high and a low scenario. Mexico is presented on a net basis, depending on whether gas flows from the lower-48 to Mexico or visa versa. Alaska deliveries are those by pipeline only; Alaska LNG that is delivered to lower-48 gas markets is included in the LNG volumes.

Figure 1.3
Non-Traditional Gas Supply to Lower-48



Gas supply from non-traditional sources grows modestly through 2005, reflecting the offsetting effect of a growing Mexican demand for gas supplies from the lower-48. In the **High Scenario**, the growth in Mexican gas demand offsets more than half of the growth in LNG imports. As a result, the outlook for U.S.-Mexico gas trade will be a significant factor in near-term non-traditional gas supply growth.

After 2010, non-traditional gas supply surges. By 2020, non-traditional gas deliveries in the **High Scenario** to the lower-48 reach 9.1 Tcf (24.7 Bcf/d), with more than three fourths coming from LNG. In the **Low Scenario**, non-traditional gas deliveries reach 6.2 Tcf (17.0 Bcf/d) by 2020, of which three fourths also comes from LNG.

Final Observations

Non-traditional sources will play a growing role in providing incremental gas supplies to lower-48 gas markets, becoming the marginal source of gas supply and thus the price-setters in lower-48 gas markets. While the increase in gas prices since the mid-1990s has make LNG and possibly North Alaska gas economically viable in lower-48 gas markets, *an increased role of non-traditional gas sources in lower-48 gas supply will probably reduce upward pressures on future gas prices*.

The economics of non-traditional gas sources are driven more by threshold affects than depletion effects. Because of the large volumes of "stranded" gas reserves and their large remaining potential resources, prices necessary to bring about large-scale development of these sources are unlikely to show much effects of resource depletion through 2020. In fact, continued reduction in the costs of LNG might even lead to some short- to medium term downward pressures on lower-48 gas prices, if and when LNG becomes the marginal source of lower-48 gas supply.

However, market factors may put upward pressures on prices for "stranded gas" because of competition between GTL plants and gas markets for access to "stranded gas." This competition could be significant, particularly for more remote "stranded" gas sources. The extent of this competition is uncertain at this point, and needs further study.

While significant commercial gas production from hydrates is not likely until about 2020 or later, the extraordinarily large potential volumes of gas in hydrates indicates that, if gas from hydrates becomes economic, *real* gas prices will be capped for a substantial period of time. In fact, depending on the technical success in improving the economic attractiveness of gas production from hydrates, large-scale gas production from hydrates might even lead to some decline in gas prices.

CHAPTER 2

ALASKA

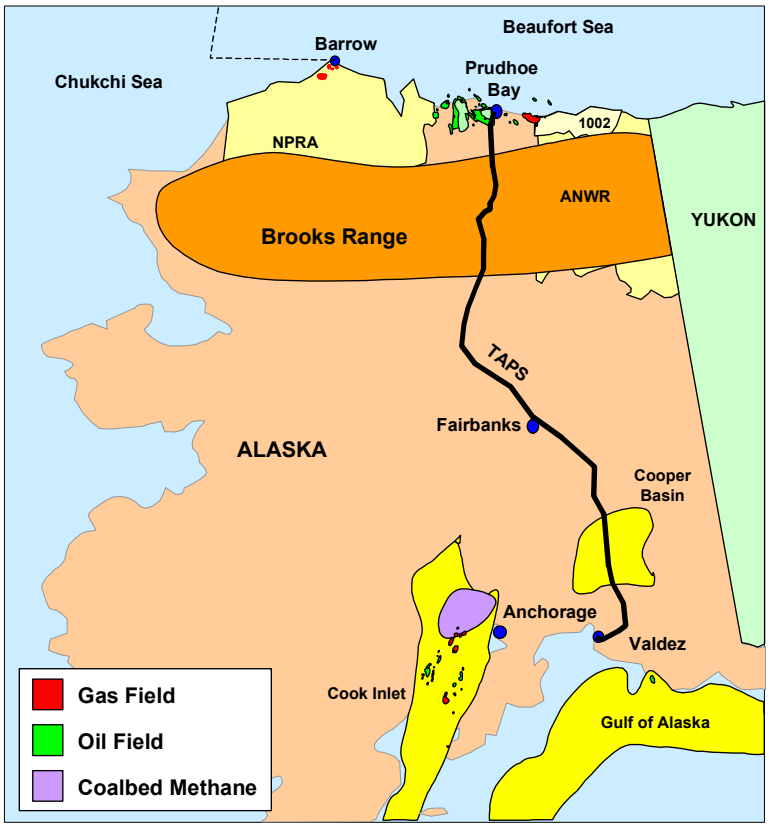
ALASKA

Introduction

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 Bcf/d for a year until 1977, when commercial oil production from Prudhoe Bay began.

Figure 2.1 indicates the three currently producing areas of Alaska: the Prudhoe Bay region, Cook Inlet, and Point Barrow. The figure also indicates areas that might begin production in the next 20 years. The National Petroleum Reserve – Alaska (NPR-A) area includes the Barrow field area. The Arctic National Wildlife Refuge (ANWR) includes the 1002 area, which has been proposed for exploration. The potential coalbed methane area in South Alaska is also indicated.

Figure 2.1
Alaska Oil and Gas Fields



Alaska gas production is primarily associated with oil production. Currently, less than 10% of Alaska gas production comes from gas wells. Industry activity is overwhelmingly oil-driven. Since 1970, less than 3% of the wells reported to the American Petroleum Institute as drilled in Alaska were gas wells.

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 9.4 Bcf/d in Alaska. However, *86%* of this production is *re-injected*. As a result, on a *marketed* basis, Alaska is only the eighth largest producing state. *Marketed* gas production in Alaska has averaged only 1.3 Bcf/d 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% is used for "domestic" energy consumption in Alaska, and this market has shown almost no growth in the last 15 years.

If *marketed gas production in Alaska grows substantially*, it *will reflect demands for gas or gas products* ***outside*** *Alaska.* This chapter will review prospects for increased *marketed* gas production in Alaska through 2020. Of particular interest will be the extent to which that increased gas production might be delivered to lower-48 gas markets. Specifically, this chapter will:

- review trends in Alaska gas production
- review Alaska gas resource prospects and their implications for future production
- identify potential markets for increased *marketed* Alaska gas production
- develop scenarios for future gas production.

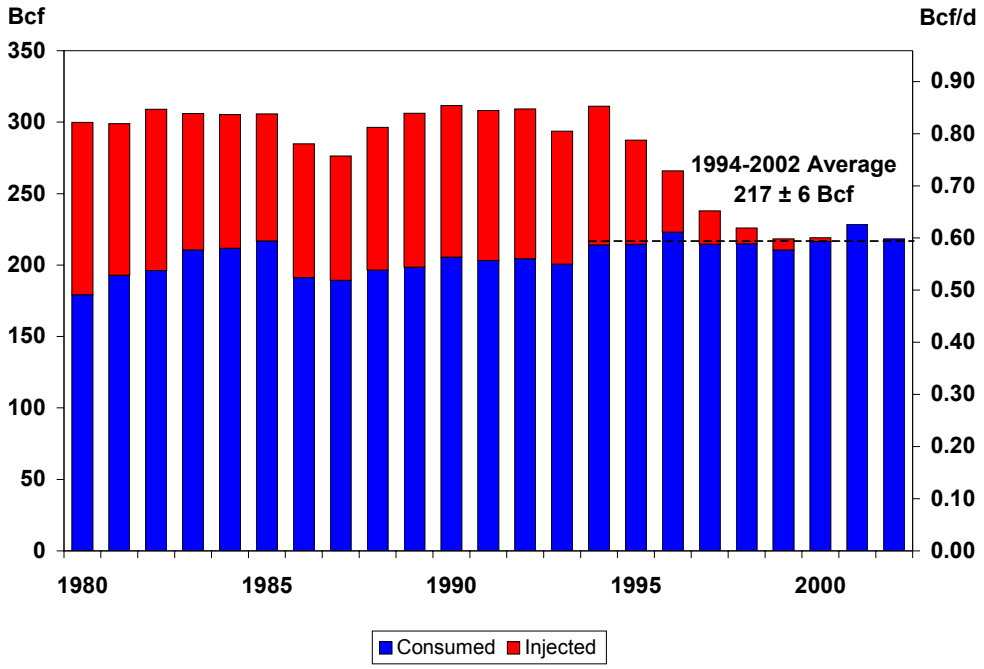
Alaska Gas Production Trends

Current Alaska gas production and markets can be divided into South Alaska Cook Inlet and North Slope. While each has different drivers, reserves levels, and prospects, they may become linked in the future. Because of the significant role of gas re-injection in Alaska, production will be allocated to gas that is consumed and gas that is re-injected.

South Alaska (Cook Inlet)

Gas production in South Alaska is used locally or exported as LNG to Japan. Figure 2.2 presents South Alaska gas production since 1980. Between 1980 and 1993, Cook Inlet gas production averaged 300 Bcf/year (820 MMcf/d). About one third of Cook Inlet gas production was re-injected, principally into the Swanson River field. Only about 200 Bcf/year (550 MMcf/d) were consumed. In 1994, the volume of gas consumed increased slightly with the expansion of LNG exports to Japan.

Figure 2.2
South Alaska Gas Production



Since 1994, Cook Inlet gas production has declined, but gas consumption has remained stable, averaging 217 Bcf (590 MMcf/d) per year (1994-2001). This is because the volume of gas that was re-injected also declined. Since 2000, no Cook Inlet gas production has been re-injected. In the first six months of 2002, Cook Inlet gas production averaged 600 MMcf/d, 30% less than its 1994 level.

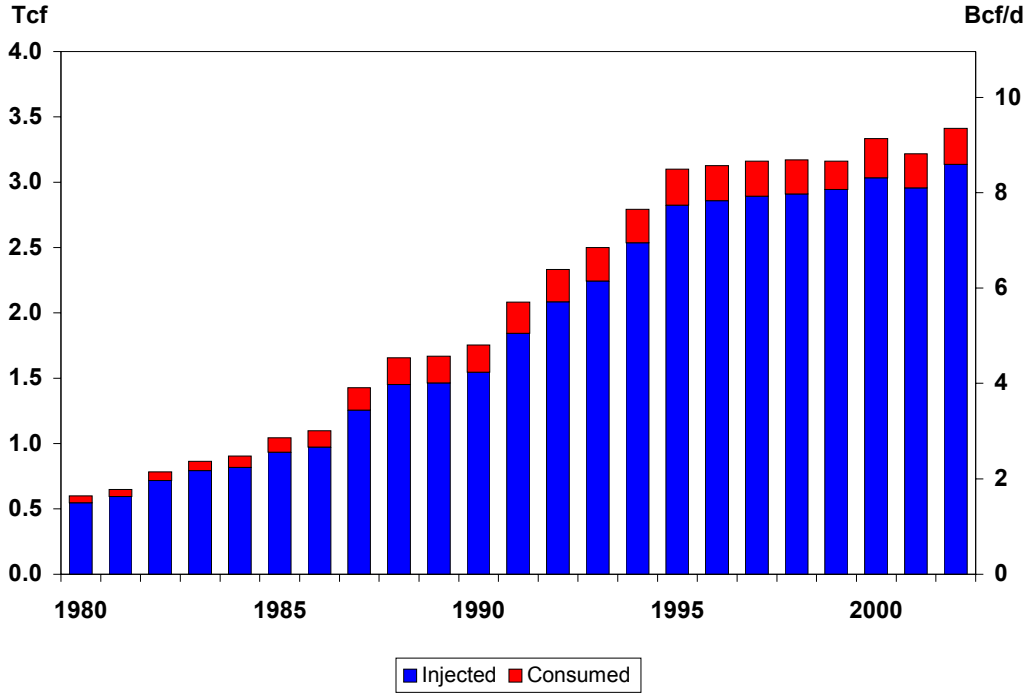
Production prospects in the Cook Inlet area are uncertain. Current gas reserves are 2.5 Tcf, resulting in a reserves-to-production (RP) ratio of about 11. Only three new fields have begun production since 1990, and only one of these (Ivan River) had more than 10 Bcf. Unless some significant discoveries are made, production in the Cook Inlet area could begin to tail off in the near-term.

Uncertain, near-term production prospects pose significant challenges to gas consumers in the Cook Inlet area. The urea plant, which currently consumes about 25% of Cook Inlet gas production, may be at risk. On the other hand, if the Cook Inlet area could be connected to the North Slope gas or coalbed methane production could be developed North of Anchorage, this would provide opportunities for increased gas use in South Alaska.

North Alaska

Figure 2.3 presents the trend in North Alaska gas production since 1980. Unlike Cook Inlet, North Alaska gas production has increased between 1980 and 2002, although most of that growth occurred by 1995. Over the first six months of 2002, gas production is on a pace to exceed 3.4 Tcf (9.4 Bcf/d), a new record.

Figure 2.3
North Alaska Gas Production



With the exception of Barrow gas production (1.5 Bcf in 2001) and its market, gas production and consumption in North Alaska is related to oil production, especially fuel for gas re-injection. Because most of the growth in gas re-injection ended in 1995, North Alaska gas consumption has been relatively stable since 1995, averaging 264 Bcf/year (720 MMcf/d), 21% more than gas consumption in the Cook Inlet area.

Although North Alaska gas production has grown slightly since 1995, 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% in 1995 and 29% 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.

Because regulations prohibit flaring of gas from producing reservoirs, gas that cannot be consumed in North Alaska must be re-injected, or the oil cannot be produced. The re-injected gas has helped to maintain reservoir pressure, thus increasing oil recovery. When Prudhoe Bay began production in 1977, recovery was estimated to be 9.8 billion barrels. Through the end of 2001, 10.3 billion barrels have been produced, and at least 2.5 billion barrels of oil reserves remain to be recovered.

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 attractive to deliver that gas to a market. Currently, the cost of producing and re-injecting gas is covered by oil revenues, but declining oil production is leading to an increasing cost burden on unit oil production costs. The current principal economic value of gas re-injection for the Prudhoe Bay reservoir is that the oil could not be produced unless the gas were re-injected. If incremental gas sales could be developed, the added gas revenues would reduce the burden of production costs on oil, thus improving oil economics.

Resource Prospects

Alaska gas production and markets are at a transition point. In the *Cook Inlet* area, *new supplies will be needed* in the near term to maintain current gas demand. The critical issue for Cook Inlet markets is whether these new supplies would be obtained from new discoveries in South Alaska or by delivering gas from North Alaska.

In North Alaska, the relative economics of gas production for delivery to a market is becoming more attractive relative to continued re-injection. While discoveries to date and current wellhead production could support deliveries of the large volumes of North Alaska gas to market at the beginning of these deliveries, new discoveries would be needed over the long term to maintain or expand gas deliveries.

South Alaska

Figure 2.4 indicates South Alaska areas that currently produce or might produce gas in the next 20 years. Currently, only the Cook Inlet area (onshore and state waters) is producing. Potential onshore producing areas are the Copper Basin and Gulf of Alaska coast. Potential offshore producing areas are Cook Inlet federal waters and the Gulf of Alaska. Interest in coalbed methane resources in Cook Inlet area has also developed. The 2000 Potential Gas Committee (PGC) report (as of December 31, 2000) estimates that the "entire Cook Inlet basin may contain about 250 Tcf of in-place coalbed methane resources" in coal seams with net "thickness up to 175 feet".

Figure 2.4
South Alaska Discoveries and Prospective Areas

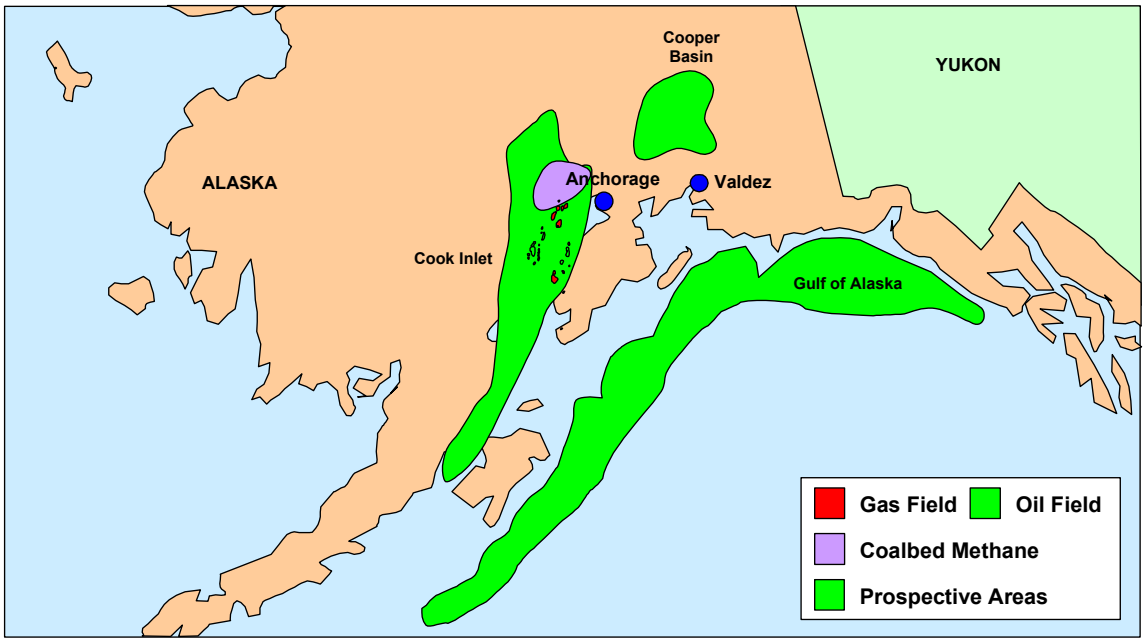
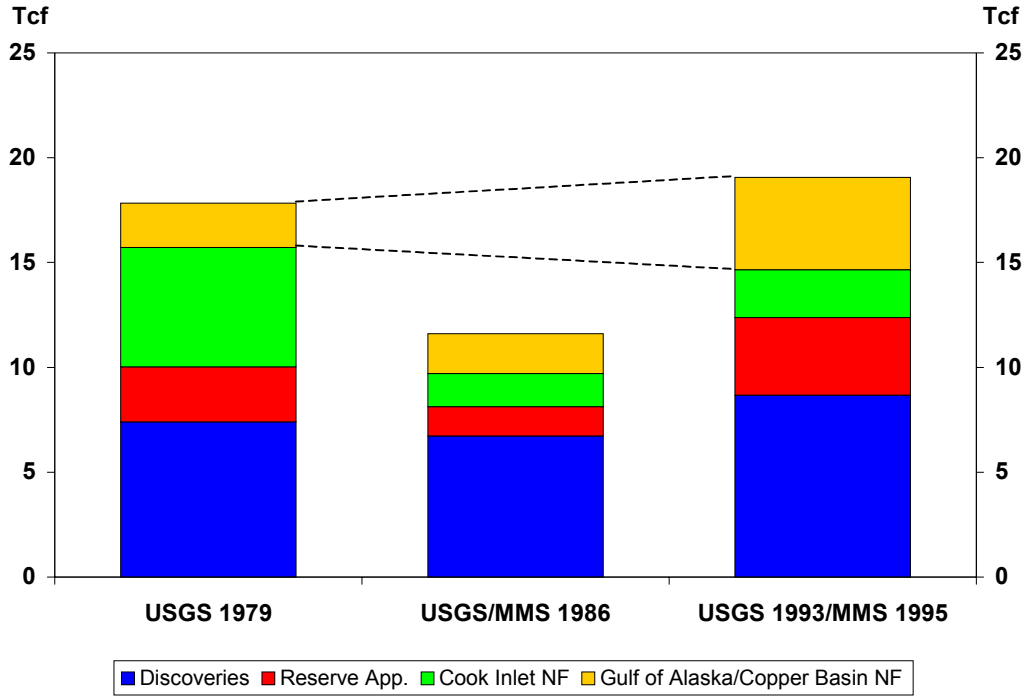


Figure 2.5 presents the trends in gas resource estimates made by the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) since 1979 for South Alaska. New field (NF) resource potentials are allocated to Cook Inlet and Gulf of Alaska/Copper Basin. While gas resource estimates for South Alaska have grown since 1979, this growth reflects higher expectations for the gas resource base in federal waters (MMS). At this point, however, it appears that production from federal waters is unlikely to develop until after 2010 and possibly 2020.

Figure 2.5
South Alaska Gas Resource Dynamics



All commercial discoveries to date have occurred in the Cook Inlet area (onshore and state waters). The most recent resource estimate (as of 1993) is somewhat less than the estimate as of 1979. This erosion is consistent with the limited discoveries in the area since the 1980s. While some wildcat wells have had significant oil or gas shows since the 1990s, they have yet to translate into significant economic discoveries.

Trends in resource estimates for Cook Inlet suggest that Cook Inlet gas production has peaked, and may begin to decline in the near-term. A critical uncertainty for South Alaska production is whether coalbed methane gas production is a near-term prospect. If only 10% of the 250 Tcf of in-place coalbed methane resources that the PGC has cited for South Alaska could be recovered, this would more than double the Cook Inlet gas resource base, and Cook Inlet would have a coalbed methane resource comparable to that currently estimated for the San Juan or Powder River basins.

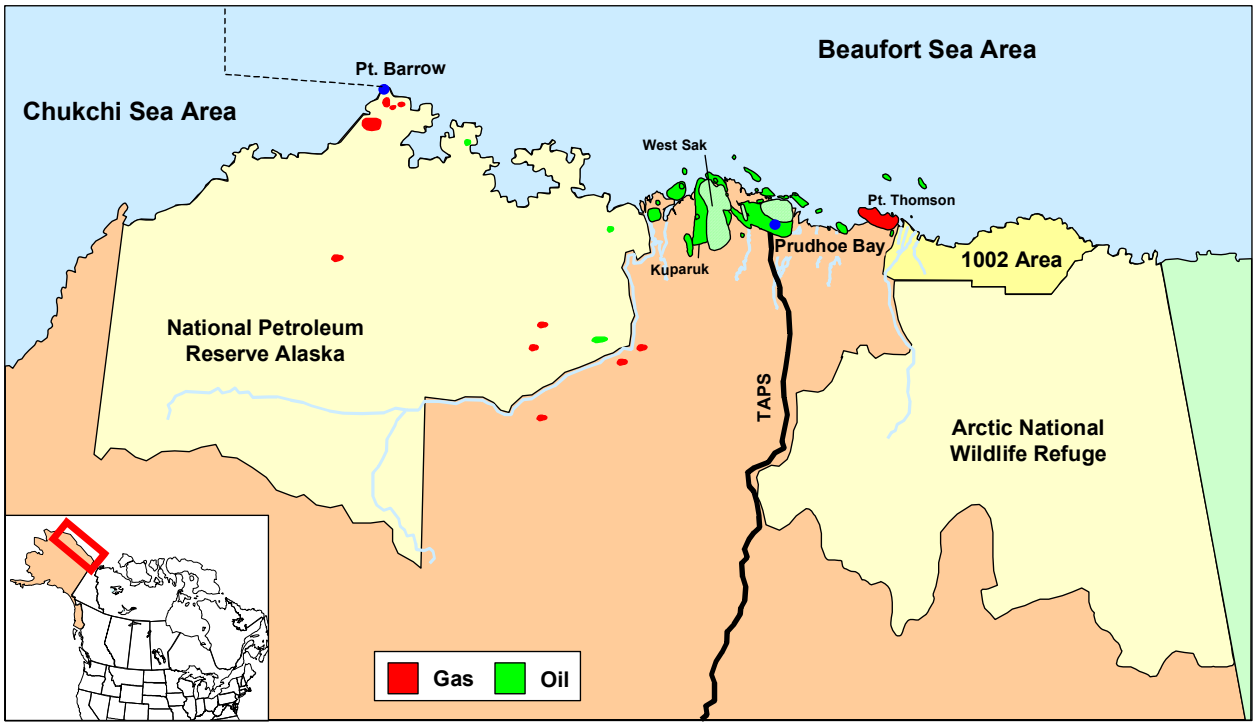
If coalbed methane production can develop in the near term, than Cook Inlet gas production could be sustained at current levels and might even grow. If coalbed methane production is a longer term

option, then prospects for South Alaska gas supply remaining at current levels for the rest of the decade may be limited.

North Alaska

Figure 2.6 indicates North Alaska areas that produce or could produce gas. Currently, only the Prudhoe Bay area and Barrow are producing. Potential onshore producing areas are the National Petroleum Reserve – Alaska (NPR-A) and the Arctic National Wildlife Refuge (ANWR), which includes the 1002 coastal area that the Federal Government has proposed to open for exploration and development. Potential offshore producing areas are in the Beaufort Sea and Chukchi Sea.

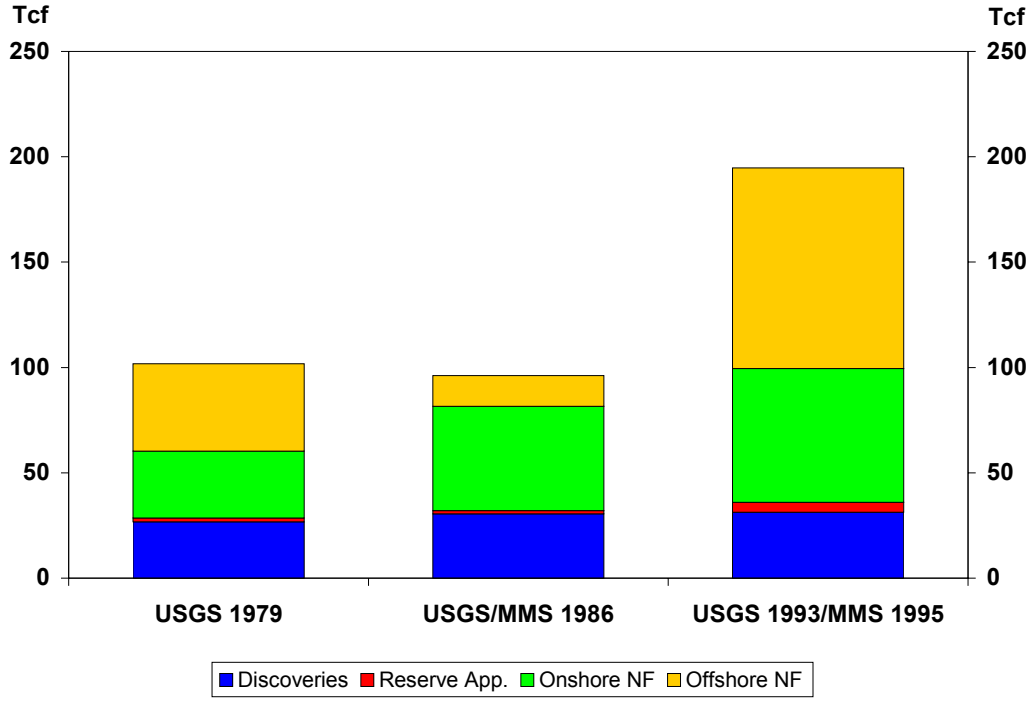
Figure 2.6
North Alaska Discoveries and Prospective Areas



Interest in coalbed methane resources in North Alaska area has also developed, and the Alaskan government (in cooperation with federal agencies) is undertaking a project to drill two exploratory wells at Wainwright, in the far Northwest corner of Alaska, for local use. The 2000 Potential Gas Committee (PGC) report (as of December 31, 2000) estimates that the Northwest Alaska, which contains the largest coal deposits in Alaska, may have an in-place coalbed methane resource in excess of 800 Tcf. However, given its remote location and the prospects for conventional gas in the NPR-A, it is unlikely that the coalbed methane resource in North Alaska would be developed for anything but local, roadless markets, such as Wainwright.

Figure 2.7 presents the trends in gas resource estimates made by the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) since 1979 for North Alaska. North Alaska ultimate gas resource estimates have more than doubled since 1979, and most recently, are almost 200 Tcf. While most of this growth reflects a more than doubling of resource expectations for the offshore area, the onshore resource has increased two thirds since 1979.

Figure 2.7
North Alaska Gas Resource Dynamics

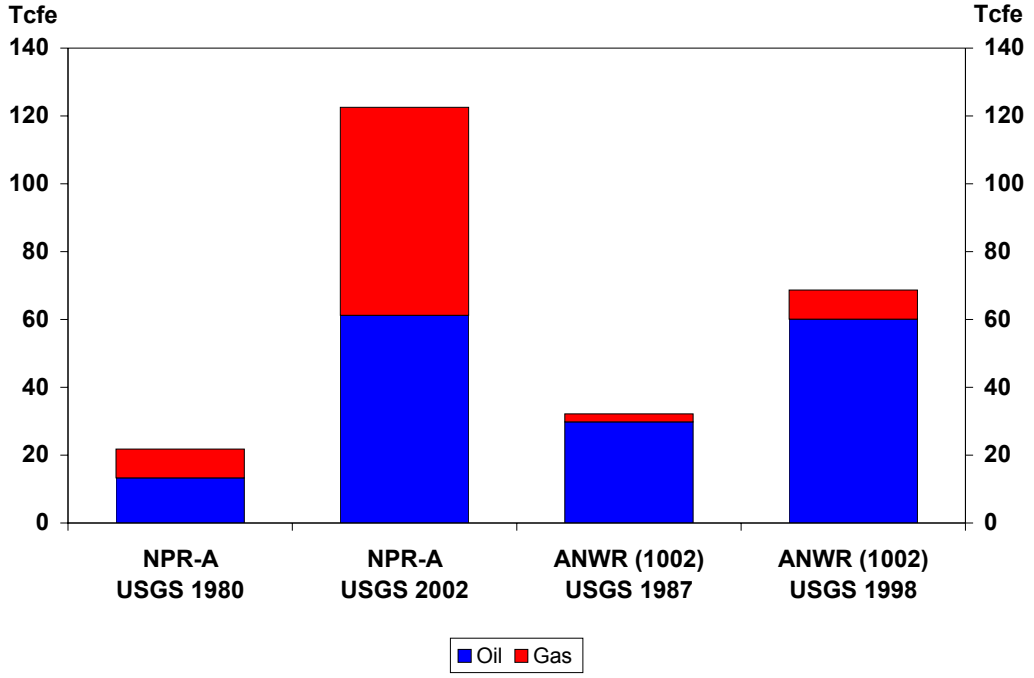


Because *only 15%* of the current estimated gas resource base has been *discovered to date*, depletion of the resource base over the next 20 years is unlikely to put much upward pressure on gas prices. If resource potentials continue to grow in North Alaska, then resource costs may decline somewhat during the next 20 years.

About 60% of the USGS/MMS hydrocarbon resource on the North Slope is oil, implying that much of the North Slope resource potential could be *associated gas*. Thus, future oil exploration could make large incremental volumes of gas available for delivery from the North Slope. Because current oil exploration carries all exploration and development costs, the additional cost to produce associated gas from a new North Slope oil discovery could be quite modest. The cost to ship the gas to a market is another issue.

The USGS has recently published area-specific studies for North Alaska assessing resource prospects for the 1002 part of ANWR plus adjacent state waters and native lands (1998) and NPR-A (2002). Figure 2-8 shows that these new estimates are substantially higher than previous estimates and that North Alaska, particularly *NPR-A*, will be *more gas-prone* than previous expected. The large increase in the NPR-A resource suggests that significant oil and gas exploration activity could occur in Northwest Alaska.

Figure 2.8
NPR-A/ANWR (1002) Oil and Gas Resource Dynamics



To date, three fields with recovery exceeding one billion BOE have been discovered in North Alaska: two oil fields, Prudhoe Bay, Kuparuk; and one gas field, Point Thompson. If 10% of the oil-in-place in the West Sak sands can be recovered, then a fourth billion BOE oil field exists. Only the Permian Basin and Onshore California have this many billion BOE fields. Because billion BOE fields are not orphans, this suggests that the average yield of North Alaska sediments might be comparable to average sediment yields in the Permian Basin and Onshore California.

Figure 2.9 compares sediment yields for North Alaska based on the USGS 1993/MMS 1995 resource estimate to sediment yields in other North American areas. The estimates for other basins are taken from the resources used in the 1997 GRI Baseline Projection.

Figure 2.9
Sediment "Productivity" of North Alaska vs. Other North America Regions

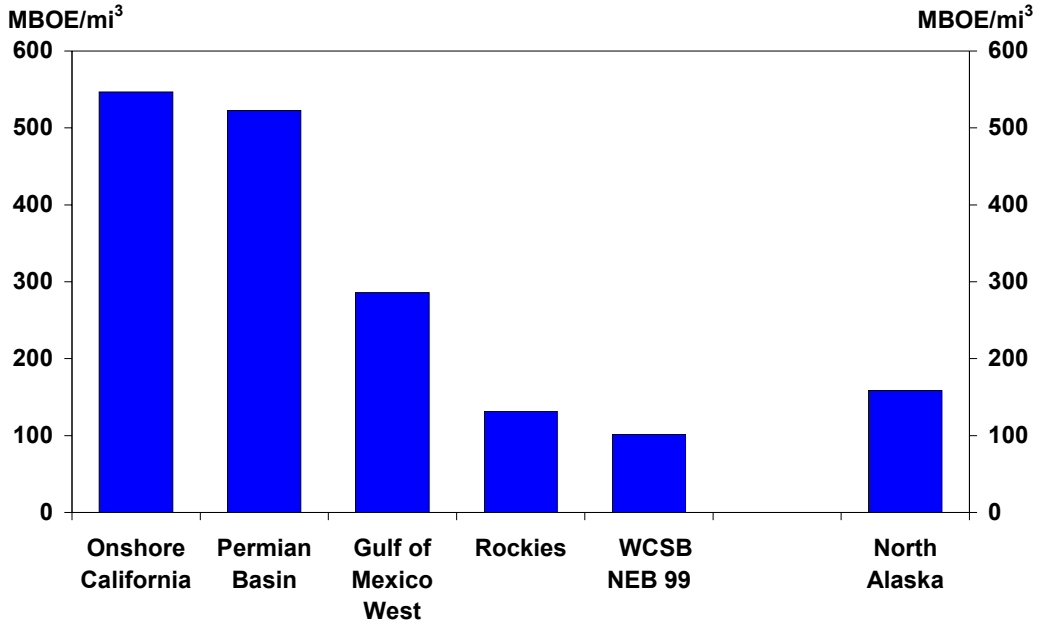


Figure 2.9 indicates that the sediment yield for North Alaska implied by the USGS 1993/MMS 1995 estimate is comparable to that expected for the Rockies and Western Canada in the 1997 GRI Baseline Projection. It is slightly more than half (55%) of the Western Gulf of Mexico yield, even though MMS reports that the Gulf of Mexico Federal Waters have no billion BOE field. The largest Gulf of Mexico producing field (Eugene Island 330) as of December 31, 1999 has 756.6 million BOE proved reserves.

Although North Alaska has a comparable number of billion BOE fields to the Permian Basin and Onshore California, its sediment yield is less than one third the yields for the Permian Basin and Onshore California. This suggests that future estimates of North Alaska oil and gas resources will grow substantially. If North Alaska sediments were only half as productive as the sediments in the Permian Basin or Onshore California (and comparable to West Gulf of Mexico), the resource base in North Alaska could be 400 Tcf, double the most recent USGS/MMS estimate.

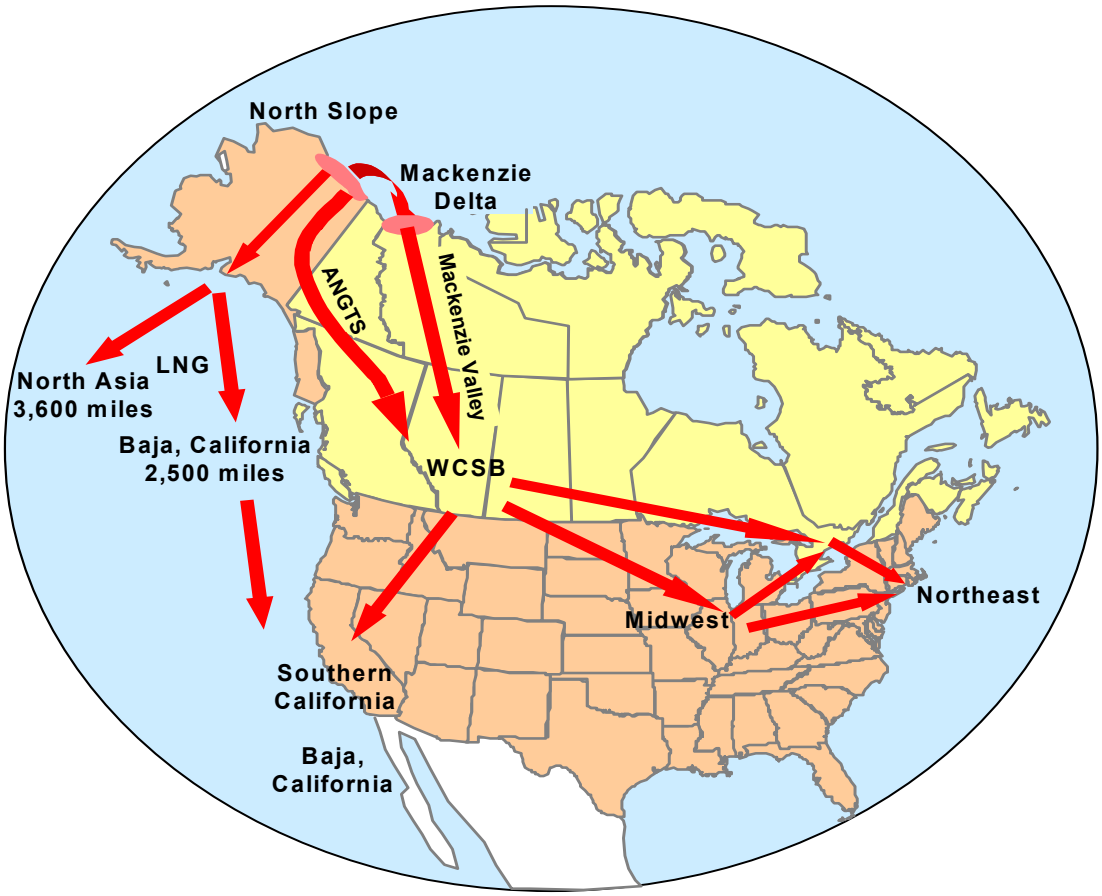
Therefore, North Alaska *marketed* gas production could grow substantially, possibly peaking near 10 Tcf. *The critical question is whether such a large production potential or its products can be delivered to market.*

Alaska Gas Markets

If *marketed* Alaska gas is to grow substantially, its markets will mostly be outside Alaska. While *North Alaska* ***marketed*** *gas production* could grow substantially in the future, its *growth will depend on major investments to move North Alaska gas to market*. Given trends in resource estimates, *marketed* gas production in South Alaska is unlikely to grow substantially unless coalbed methane production surges in the next decade.

Figure 2.10 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 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 used in the movement of 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.

Figure 2.10
Northern Gas Market Options



Wellhead prices for North Alaska gas will be much less than Gulf Coast gas prices because Northern gas will have to travel up to 3,600 miles to reach North American gas markets in Southern California or the Midwest, compared to 1,500 miles from Gulf Coast to the Northeast. While this will have *negative impacts on perceptions of the profitability* of Northern gas sales to lower-48 and Canadian gas markets, low netback prices do not necessarily imply a lack of profitability. North Alaska oil has always sold at a significant discount to Gulf Coast oil prices, particularly in its first decade of production. Between 1981 and 1985, North Slope oil sold for an average US$11.50/Bbl (US$2/MMBtu) below Texas oil prices. After more than two decades of pipeline amortization, North Slope oil still sells almost US$5/Bbl below Texas oil prices.

There are four principal options to move North Alaska gas or its products 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 final option is to convert North Alaska gas to liquids via gas-to-liquids (GTL) technology in either North Alaska or South Alaska.

North Alaska to Western Canada

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.

Alaska Highway Corridor Option

This corridor is the site of the proposed Alaska Natural Gas Transportation System (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. Capital expenditures to construct a pipeline in this corridor will be significant ($8-10 billion).

To keep gas transportation charges competitive for this corridor, volumes for proposed projects have been about 4 Bcf/d, with some discussion of volumes approaching 6 Bcf/d. Because of the large capital investments involved in the 4-6 Bcf/d projects, a smaller-volume pipeline (2.5 Bcf/d) that could be expanded in the future to 4 Bcf/d or more is also an option. This would allow Alaska gas to be introduced into the North American gas market with less downward pressure on North American gas prices, and defer some capital investment into the future.

The ANGTS project has the advantage of having approval from both the U.S. and Canadian governments via legislation, although not regulatory approval. These approvals could reduce the time to begin construction for at least the Prudhoe Bay-Boundary Lake portion of the system, which could offset some of its higher capital costs. The Alaskan Highway corridor could also provide gas to the Anchorage-Fairbanks corridor, which has most of the Alaskan population, and the Yukon population centers.

Depending on the volumes, the toll to move Alaska North Slope gas to Western Canada ranges from US$1.40/MMBtu (2.5 Bcf/d) to less than US$1/MMBtu (6 Bcf/d) at a 12% discount rate. A 15% discount rate adds 20-40 US¢/MMBtu to the toll. These transportation charges are an indicator of the gas price differential between North Alaska and Western Canada gas prices.

Over the Top Corridor Option

This option was the initial route proposed to bring gas from the North Slope of Alaska to North American gas markets in the late 1960s. Because a land route along the coastal plain is now precluded by the Alaska National Wildlife Refuge (ANWR) and the Ivvavik National Park in the Yukon, the North Slope-Mackenzie Delta leg would be offshore.

The Over the Top option has significant implications for Mackenzie Delta development. Current reserves in the Mackenzie Delta make construction of a pipeline with an initial flow exceeding 0.8 Bcf/d risky. If Mackenzie Delta producers were confident that an Over the Top option would be constructed, this would substantially reduce the risk of initially delivering more than 1 Bcf/d down the Mackenzie Valley from Mackenzie Delta gas reserves. This is because gas flows from the North Slope would backstop initial flows of Mackenzie Delta gas down the Valley to Alberta. However, because both Prudhoe Bay and Mackenzie Delta gas production will be flowing down the Mackenzie Valley, priority of access to the Mackenzie Valley portion of the pipeline may introduce some political, contractual, or operational challenges.

This distance to move North Slope gas to the North American gas transmission network is about 300 miles (15%) shorter than the Alaska Highway Corridor, but the higher cost to construct an offshore pipeline in the Beaufort Sea offsets some of this advantage. As a result, transportation tolls to move gas from North Alaska via this option will probably not be that different from those for an Alaskan Highway option for a comparable throughput. In addition, the North Slope-Mackenzie Delta leg would probably face the strongest environmental and political opposition of the Northern gas transportation options.

North Alaska to South Alaska

The pipeline length in this corridor is about 800 miles, following the oil pipeline (TAPS) right-of-way. LNG could be shipped 2,500 miles to Baja California (a proposed site for a regasification terminal), with another 100 miles of pipeline to connect to the Southern California market. For a 2.5 Bcf/d pipeline from the North Slope, the total gas pipeline toll (Alaska *and* California) would be about US$0.60/MMBtu. This option could also provide gas to the Fairbanks-Anchorage corridor. Interest has revived in this option, but its prospects are uncertain at this point.

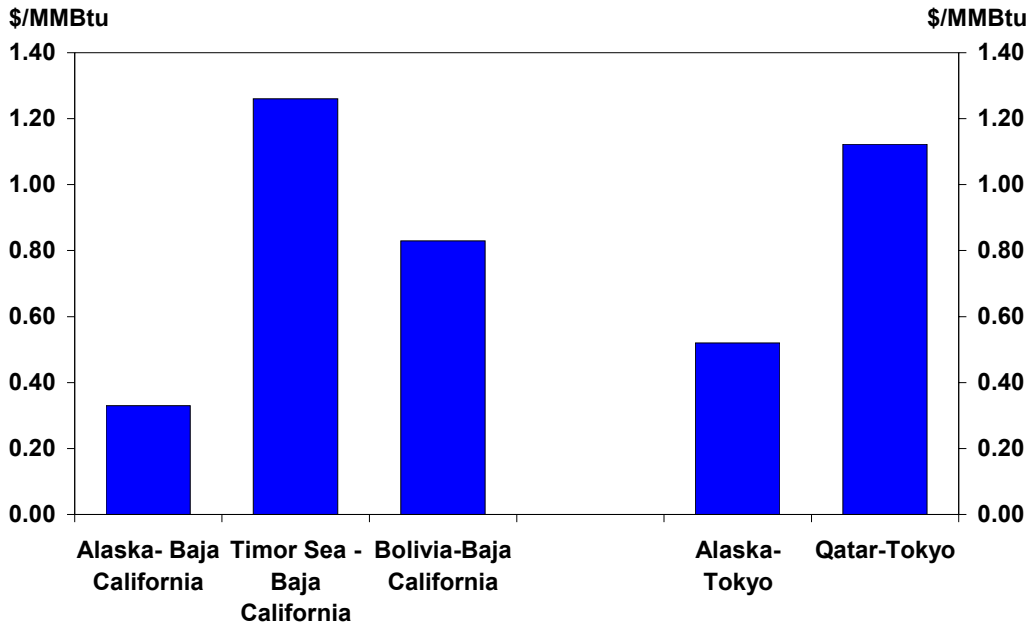
LNG from South Alaska would have its principal markets on the Pacific Coast of North America and in North Asia. Initial deliveries to the Pacific Coast could be to the proposed Baja California terminal, and deliveries to North Asia could go to Tokyo. In both markets, however, Alaska LNG will face competition.

In Baja California, this competition would be from the East Indies (e.g., Timor) or South America (e.g., Bolivia via Chile). In North Asia, Alaska LNG would face strong competition from LNG sources in the East Indies, Australia, and Sakhalin Island. However, Alaska LNG might be able to compete in North Asia with gas from new LNG capacity in the Persian.

With the exception of gas from Bolivia, most gas production sources for LNG that Alaska would compete with would be much closer to a liquefaction terminal than North Alaska. However, Alaska LNG would be closer to Pacific Coast or North Asia markets than many LNG sources. The shipping advantage for Alaska LNG might offset the costs to move North Alaska gas to a liquefaction terminal in South Alaska.

Figure 2.11 compares shipping costs for Alaska LNG to shipping costs for competing sources on the Pacific Coast or in North Asia. For LNG deliveries to a Baja California LNG terminal, Alaska LNG has a 50¢/MMBtu (Bolivia) to 90¢/MMBtu (Timor Sea) shipping advantage. Because this is comparable to or less than the cost to move gas from North Alaska to South Alaska, Alaska gas should be able to compete with South American and East Indies gas on the Pacific Coast.

Figure 2.11
Alaska LNG Price "Window"



At Tokyo, Alaska LNG would have a 60¢/MMBtu shipping advantage over LNG from Qatar, about the cost to move gas from North Alaska to South Alaska. If the price for gas delivered to a pipeline in North Alaska could match Qatar gas prices delivered to an LNG terminal in Qatar, then Alaska LNG could compete with Qatar on a price basis. However, such price competition would be very tough.

Gas-to-Liquids (GTL)

GTL may play a very significant role in providing a market opportunity for North Alaska gas. The technology has improved substantially in the last decade, and costs have declined. As will be shown in Chapter 6, GTL is likely to be an attractive economic option for "stranded" gas reserves at plant-gate gas prices well above the 50-75¢/MMBtu often-cited in the literature. Given the large volumes of re-injected associated gas in North Alaska, GTL may be option for North Slope gas.

An Alaskan GTL plant could be located in North Alaska or South Alaska. In North Alaska, GTL production could flow to South Alaska using the existing TAPS line. Currently, the TAPS line is running only about half full (1.1 MMBbl per day), and utilization is likely to decline in the future. On the other hand, moving gas to South Alaska could supply both GTL and LNG liquefaction capacity in South Alaska, *plus* supply Alaska gas markets in the Fairbanks – Anchorage corridor.

Figure 2.12 compares the relative gas prices for South Alaska and North Alaska alternatives. In South Alaska, the gas price is at the "plant-gate" to a GTL or an LNG facility. In North Alaska, the gas price is at the "plant-gate" of a North Alaska GTL plant or at the entrance to a North Alaska pipeline going to South Alaska for delivery to an LNG plant. The GTL product is distillate, and the LNG market is Baja California. The California gas market price is $4/MMBtu, and the South Alaska oil price is $25/Bbl (equivalent to about WTI $27/Bbl on NYMEX).

Figure 2.12
"Plant-Gate" Gas Prices: Alaska LNG or GTL

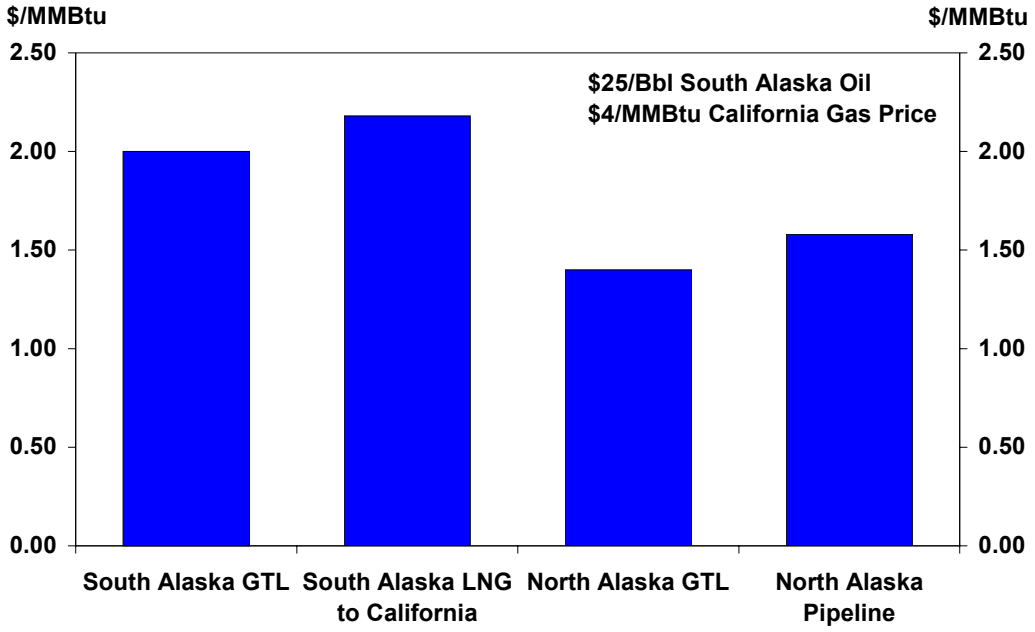


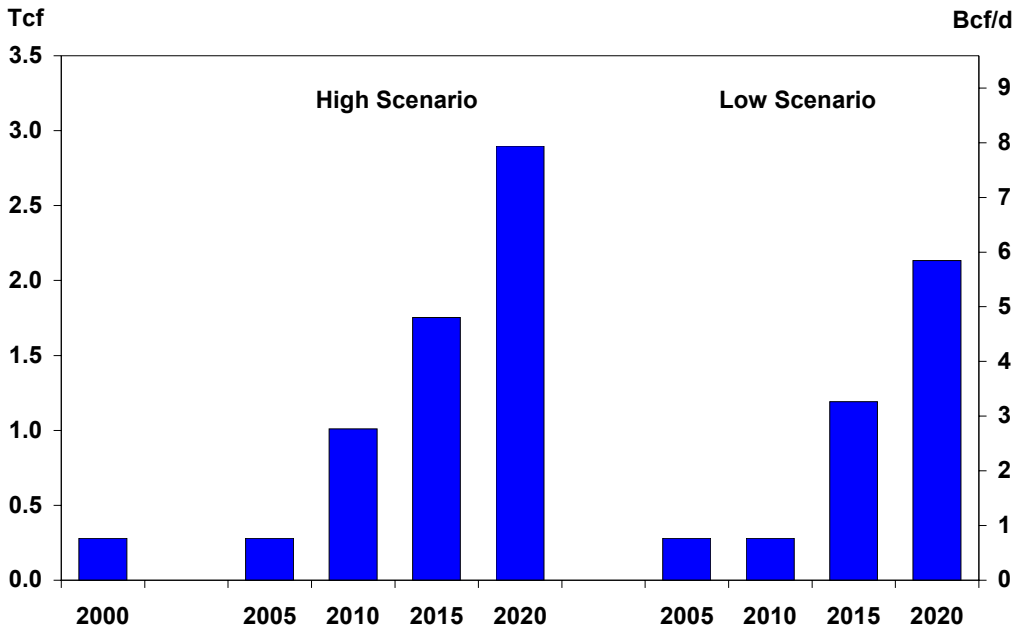
Figure 2.12 shows that GTL and LNG are comparable market options for North Alaska gas, whether the GTL facility is in South Alaska or North Alaska. Other factors, which are not included in the comparisons of Figure 2.12, will enter into the decision of a GTL location. Among those issues,

which could add to a gas "plant-gate" price for the GTL option, are the "premium" price that GTL distillate products might command in a market, such as California, and the economic advantage of using the available capacity in the TAPS oil pipeline.

North Alaska Gas Scenarios

Figure 2.13 presents two scenarios for North Alaska gas production through 2020. In the **High Scenario**, North Alaska gas begins to be delivered to outside markets in 2010. Deliveries grow through 2020, reaching 7 Bcf/d by 2020. Including North Alaska field use, North Alaska gas production is 2.9 Tcf (8 Bcf/d) by 2020. In the **Low Scenario**, deliveries to outside markets begin in 2012, and only reach 5 Bcf/d by 2020. Including field use, North Alaska gas production is 2.1 Tcf (6 Bcf/d) by 2020.

Figure 2.13
North Alaska Production Scenarios



While new discoveries are not really needed until after 2010, a successful exploration program adding substantial new reserves needs to be underway by about 2012 at the latest in the **High Scenario** and 2016 at the latest in the **Low Scenario**. In the **High Scenario**, *about 30 Tcf of new gas discoveries* need to be made in North Alaska through 2020 to support the growth in production. In the **Low Scenario**, only about *20 Tcf of new gas discoveries* are needed through 2020. Given resource prospects for North Alaska, these levels of reserve additions are not likely to put much upward pressure on North Alaska gas prices.

Final Observations

Marketed Alaska gas production could be on the verge of significant growth that might begin as early as 2010. By 2020, *marketed* Alaska gas production should exceed 8 Bcf/d, and might approach 10 Bcf/d if coalbed methane production in South Alaska develops rapidly. However, prospects for *large-scale* coalbed methane development in South Alaska are too uncertain at this point to be included in a production outlook.

Although Alaska gas production is likely to grow substantially*, a large part of this growth may not be delivered to North American gas markets*. The significant advances in GTL technology suggest that a large share of Alaska gas production may be converted into liquids. If LNG terminals are constructed in South Alaska, a noticeable share of that LNG may find its way to North Asia or perhaps Mexican gas markets. Therefore, the *greater uncertainty* surrounding Alaska gas prospects through 2020 may be *where Alaska gas is marketed, not whether it grows significantly*.

CHAPTER 3

LNG IMPORTS

LNG IMPORTS

Introduction

When LNG imports into the United States began in 1970, they were priced on an f.o.b. cost plus basis. As a result, they were seen as a high-cost source of natural gas, which would be largely limited to seasonal uses that could economically accommodate their high prices. *In 1988, however, LNG import* contracts were changed to base LNG prices on *market prices* rather than f.o.b. cost plus. As a result, LNG is now viewed as a competitively priced source of increased U.S. gas supplies on a year-round basis.

LNG currently provides less than 1% of U.S. gas supply. That share, however, is expected to grow substantially, because U.S. gas demand is expected to grow faster than U.S. gas production. Some projections of this "gap" between U.S. gas demand and production are almost 10 Bcf/d in 2010 and could exceed 15 Bcf/d by 2015 in some cases. As a result, more than 25 new LNG terminal projects are under consideration in the United States, Canada, or Mexico with scheduled operation dates before 2010.

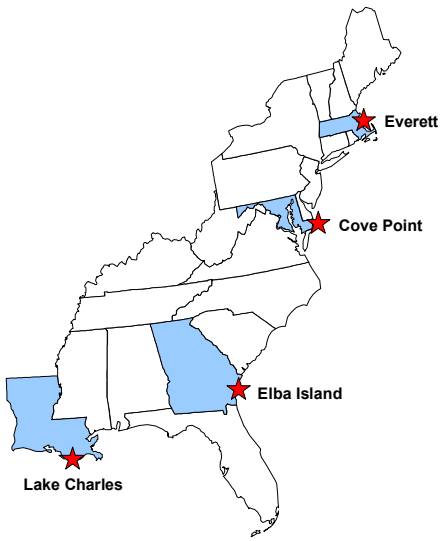
This chapter will review prospects for increased LNG deliveries to U.S. gas markets through 2020. Specifically, the chapter will review:

- U.S. LNG import trends
- LNG economics
- U.S. LNG terminal prospects
- LNG availability to U.S. markets
- U.S. LNG import prospects.

Although pipeline units (cubic feet of gas) are used in this chapter, many discussions of LNG use liquid measures, such as cubic meters or metric tons (tonnes). Because LNG can have varying shares of natural gas liquids (In 2000, the Btu content of LNG imports into the United States ranged from 1,050 Btu/cf [Trinidad] to 1,173 Btu/cf [Oman and Australia].), conversions from LNG liquid measures to gas pipeline volumes can vary. Listed below are some *nominal conversions* that are used in this chapter.

LNG Liquid		Pipeline Gas
One cubic foot	contains	600 cubic feet
One cubic meter	contains	21 Mcf
One metric tonne	contains	49 Mcf

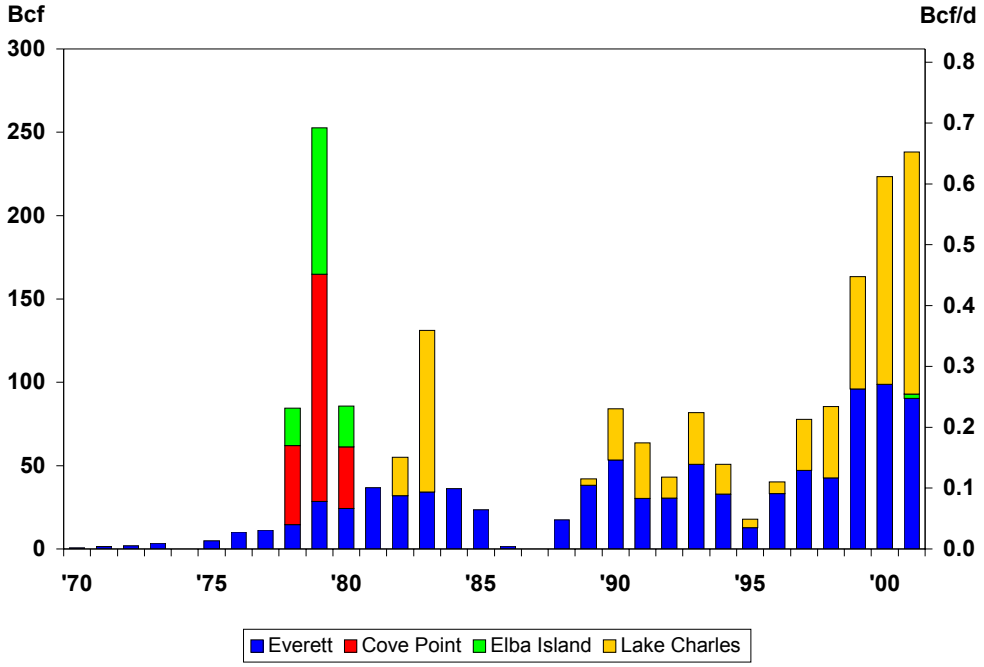
U.S. LNG Import Trends



The United States has four LNG receiving terminals, located in Everett, Massachusetts; Cove Point Maryland; Elba Island, Georgia; and Lake Charles, Louisiana. Only the Cove Point terminal was closed as of mid-2002, and it is expected to re-open in late 2002 or early 2003. Annual capacity of these four terminals is currently 2.4 Bcf/d, but plans are underway to expand capacity to 3.5 Bcf/d by 2005-6. Ultimately, capacity for the four terminals could exceed 4 Bcf/d.

LNG imports began in 1970 at the Everett, Massachusetts, terminal. Figure 3.1 presents LNG imports by terminal since 1970. With the opening of the Cove Point and Elba Island terminals in 1978, LNG imports reached 253 Bcf in 1979, their highest level to date. *In April 1980, Algeria stopped delivering LNG* to Elba Island and Cove Point because the terminals would not accept a 200% increase in Algerian f.o.b. LNG prices linked to the increase in world oil prices.

Figure 3.1
U.S. LNG Imports: 1970 - 2001



In 1981, only the Everett terminal was active, and LNG imports declined to 37 Bcf. LNG imports grew in 1982 with the opening of the Lake Charles terminal, reaching 131 Bcf in 1983. In

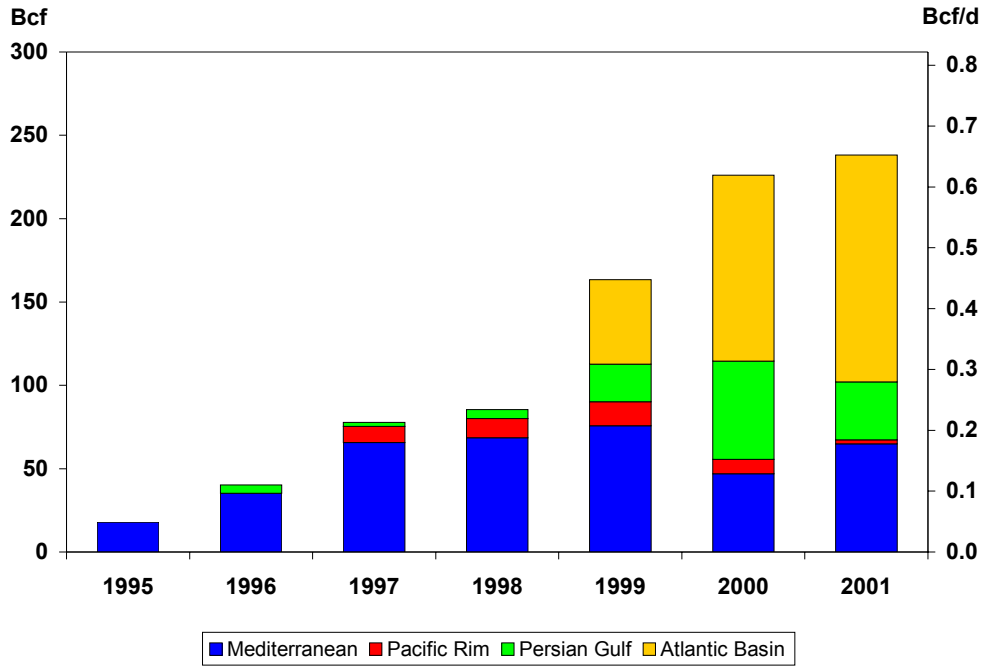
December 1983, however, Lake Charles invoked *force majeure*, because high prices made LNG unmarketable. Once again, Everett was the only active terminal.

With the gas price collapse in 1986-87, only one spot cargo (1.7 Bcf) from Indonesia was imported into Everett in 1986, and none in 1987. Following *renegotiations* of contracts with Algeria to set LNG prices on a *competitively priced "landed" basis instead of a cost-plus f.o.b. basis*, imports resumed at Everett in 1988 and at Lake Charles in 1989. Elba Island resumed operation in late 2001.

Since 1995, LNG imports have grown substantially, exceeding 200 Bcf in 2000. In 2001, LNG imports were on a pace to set a new record, but following September 11 and an erosion in U.S. gas prices, LNG imports declined, but appear to be recovering in 2002 (LNG imports in April 2002 exceeded 12 Bcf.).

With the exception of a single cargo from Indonesia in 1986, all U.S. LNG imports through 1995 came from Algeria (Mediterranean). Since 1996, LNG sources have diversified, including some sources that were thought to be uneconomic through the early 1990s. Figure 3.2 presents U.S. LNG imports by regional source since 1995.

Figure 3.2
Sources of U.S. LNG Imports



The growth in LNG imports between 1995 and 1998 was driven principally by increased imports from the Mediterranean (Algeria), but there has been no sustained growth in LNG imports from the Mediterranean since then. Since 1998, growth in LNG imports has been carried principally by Atlantic Basin sources (Trinidad & Tobago and Nigeria). In 2001, 57% of LNG imports came Atlantic Basin sources. Some growth also occurred in LNG deliveries from the Persian Gulf. LNG imports from the Pacific regions declined after 1999, in large part due to economic recovery in the Far East.

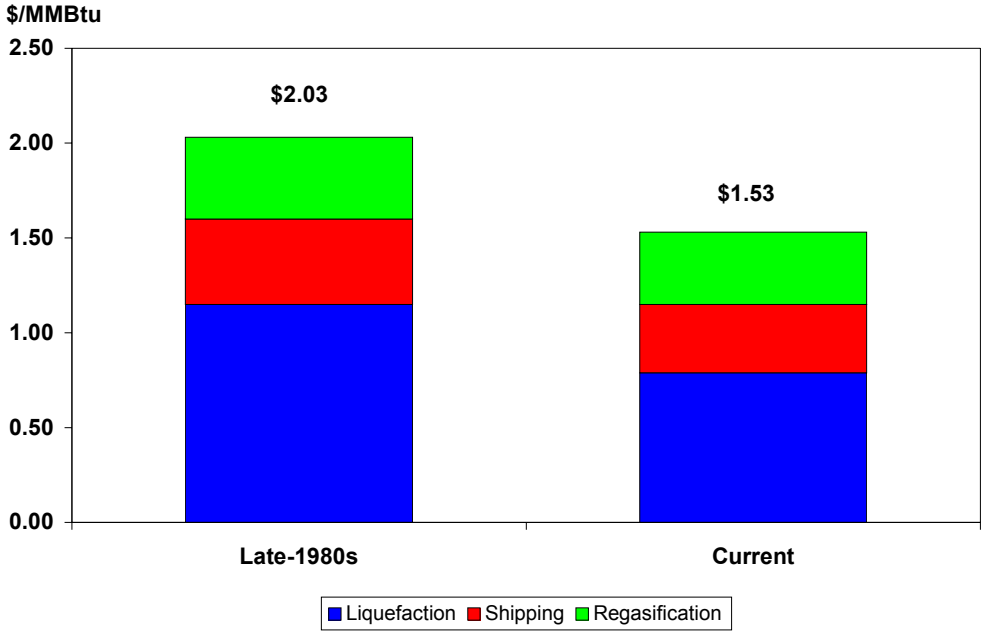
LNG Economics

If LNG imports grow substantially, they must be competitively priced to be a fuel of choice for new gas-fired power plants. Depending on the location of a U.S. LNG import terminal, this price probably cannot exceed $3.50-4.00/MMBtu before LNG begins to lose its economic attractiveness for new gas-fired power plants. This market price, however, must recover the costs of new investments to bring LNG to the United States.

The landed LNG cost is the sum of the *commodity price* at the beginning of the LNG chain plus the *costs of the LNG chain*. The LNG chain is comprised of a gas liquefaction facility, ships, and a regasification facility. The costs for each component of the LNG chain is comprised of capital recovery, O&M expenses, and gas shrinkage. Liquefaction is the largest component of the LNG cost chain for distances up to about 6,000 miles. Beyond 6,000 miles, it costs more to ship LNG than it does to liquefy gas. Shrinkage charges depend on the gas commodity price at the beginning of the LNG chain.

LNG costs have declined substantially in the last decade, improving the competitive attractiveness of LNG in the U.S. gas market. Figure 3-3 compares LNG facility costs (excludes gas shrinkage costs) that would have been incurred to move LNG 2,500 miles in the late 1980s to current facility costs. Since the late 1980s, revenues required to recover facility costs (capital and operating) have declined about *25%*. A major contributing factor to this has been lower capital costs for new LNG liquefaction facilities. Costs are likely to decline in the future.

Figure 3.3
LNG Facility Cost Changes
(2,500 Mile Shipment)



Liquefaction Costs Outlook

In the late 1980s, the capital intensity of a "green field" (new site) liquefaction facility was in the $300-400/tonne range. Currently, it is about $200/tonne. Continuing growth in train size (up to 5 million metric tons [MMt]) and improved technology are expected to reduce costs to as low as $150/tonne, a decline of up to 25% for a "green field" facility.

The capital intensity for new LNG capacity can also be reduced if new capacity is added at a site with existing LNG capacity ("brown field" site). For example, capital costs for the first train (3 MMt) at the Atlantic LNG site were $1.1 billion, or $322/tonne. Trains 2 and 3 (6.6 MMt/year) at the Atlantic LNG site have a capital cost of $1.1 billion or $167/tonne because the new trains can use some existing facilities. Two thirds of current industry plans to double liquefaction capacity in the Persian Gulf is at existing facilities. Because these expansions can utilize previous capital investments for non-liquefaction parts of the site, their capital costs will probably be low.

Therefore, *as LNG output expands, capital costs per unit of output should continue to decline, reflecting both reduced costs for new "green field" sites and capacity expansion at existing liquefaction sites*.

Shipping Costs Outlook

LNG shipping costs have declined substantially since the early 1990s. LNG ship size has increased about 10% to 138,000 m^3, and the nominal cost of a ship has declined from $260 million in 1990 to $170 million in 2001. As a result, *costs per unit of capacity* are currently more than *40% less* than what they were in 1990.

Costs per unit of capacity should continue to decline in the future. Designs to increase the capacity of an LNG tanker an additional 10% are underway.

Regasification Costs Outlook

Regasification generally accounts for the smallest portion of the LNG price chain. While current regasification facilities are located onshore, proposals have been made to locate LNG regasification terminals in the Gulf of Mexico. This may reduce opposition to new terminals, improving prospects for timely opening of new LNG capacity.

In addition, El Paso Energy has proposed to develop *floating* regasification capability by adding regasification capability to LNG tankers. This would allow an LNG tanker to dock with an offshore mooring facility, gasify LNG on the tanker, and inject the gas into a pipeline. El Paso plans to add this capability to three new LNG tankers that it has ordered.

El Paso's initial estimates of on-board gasification costs increase LNG tanker costs about $60 million (one third) to $230 million per ship. El Paso envisions the capacity of a three-tanker system to be on the order of 400-500 MMcf/d. The incremental gasification costs for three tankers appear attractive -- about one third of the costs per unit for a land terminal. If these initial estimates prove out, floating regasification would probably be more attractive than building new onshore

regasification terminals for LNG deliveries to the East Coast from most Atlantic Basin and Mediterranean LNG sources. On the Pacific Coast, floating regasification appears attractive for LNG from Alaska and possibly South America.

Implications for Future LNG Costs

LNG capital costs have declined substantially during the 1990s, and could decline up to an additional 25% for liquefaction facilities. Shipping costs may also decline somewhat. Development of offshore facilities, whether floating or fixed, offers opportunities for reductions in the risks associated with siting new regasification terminals and possibly capital costs as well. These cost reductions will further improve LNG competitiveness in the U.S. market and the attractiveness of providing gas to the LNG chain.

Overall, the current LNG facilities costs presented in Figure 3.3 might be reduced on the order of 10-20% in the coming decade. This would improve the competitive attractiveness of LNG to U.S. gas markets either by reducing LNG costs in the United States or allowing higher gas commodity prices to the exporting country.

U.S. LNG Source Economics

For U.S. LNG imports to grow on a long-term basis, the United States must provide an economically attractive market for new LNG capacity. Relying solely on the availability of surplus LNG capacity will not be sufficient to support a sustained, long-term growth in LNG imports that would take LNG to 10% or more of U.S. gas supply by 2020.

U.S. Terminal "Economics"

Figure 3.4 presents current LNG costs to deliver gas to selected LNG terminals on the Gulf Coast (Lake Charles, Louisiana), Atlantic Coast (Cove Point, Maryland), and Pacific Coast (Baja California). LNG sources are Trinidad, Nigeria, Algeria, and the Middle East for Lake Charles. Deliveries from Norway are also included for Cove Point. Deliveries to Baja California come from the East Indies and Bolivia. The liquefaction plant-gate price in the exporting country is $1/MMBtu, and the cost of capital is 12%.

Figure 3.4
U.S. Regasification Terminal Tail-Gate Prices

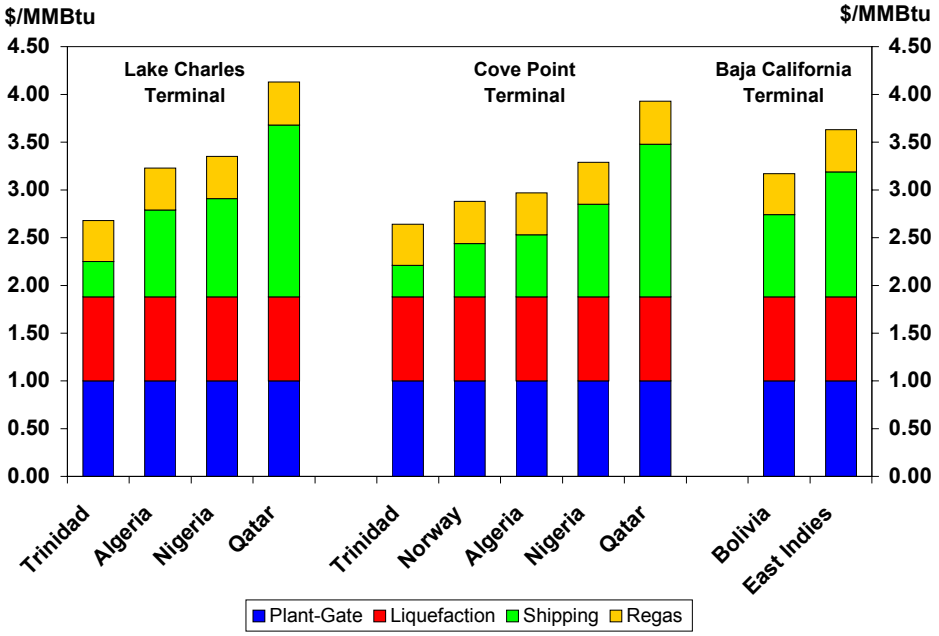


Figure 3.4 shows that gas could leave the Lake Charles terminal at less than $3.50/MMBtu for LNG deliveries from Mediterranean or Atlantic Basin sources. In fact, prices for deliveries from Caribbean sources would be less than $3/MMBtu. Gas from Qatar, however, would leave Lake Charles at more than $4/MMBtu, which may be too high for Qatar LNG to be competitively priced at many electricity power plants. As a result, at current costs, the Middle East is unlikely to be a significant long-term option as a source for LNG to U.S. gas markets unless gas can be delivered to a Middle East liquefaction plant for much less than $1/MMBtu.

Gas could leave the Cove Point terminal at less than $3/MMBtu LNG deliveries from Norway, the Caribbean, or the Mediterranean. Nigerian LNG could leave Cove Point at less than $3.50/MMBtu. While Qatar LNG would have the highest price, it could leave Cove Point at less than $4/MMBtu, allowing it to be competitively priced to electric power plants in the Cove Point region.

LNG deliveries to a Baja California terminal have been proposed from Bolivia (Sempra/CMS) or the East Indies (El Paso). Gas could leave a Baja California terminal at $3.20/MMBtu for Bolivian LNG and $3.60/MMBtu for East Indies LNG, which could be competitive in California gas markets.

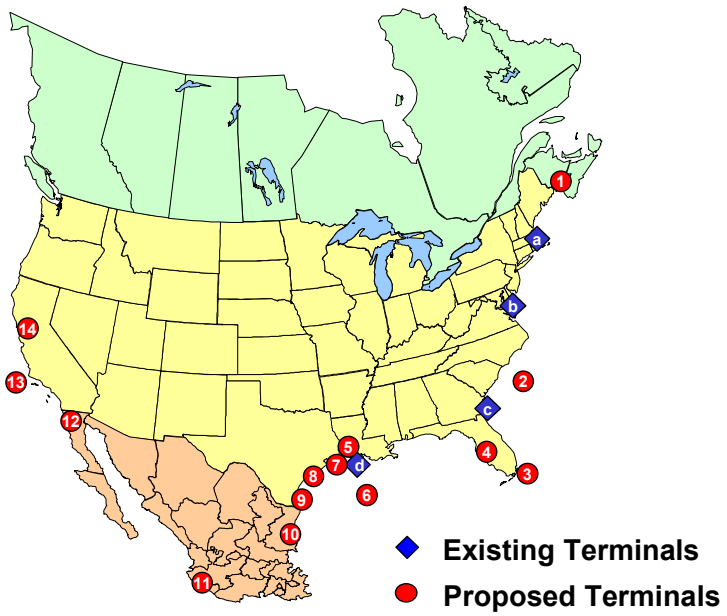
At current LNG costs, LNG deliveries from Atlantic Basin, Mediterranean, South America (Pacific Coast), and the East Indies (Pacific Coast) sources can be delivered at competitive prices to the United States. As a result, investments in gas liquefaction facilities and ships for LNG exports to the United States could be undertaken for these sources. Continued improvements on the order of 20% in liquefaction facility costs, however, could allow LNG from sources in the Atlantic Basin, Mediterranean, and South America (Pacific Coast) to enter the U.S. gas transmission network at prices under $3/MMBtu.

While LNG deliveries from the Middle East are marginal at best under current costs, a continued reduction in LNG costs could make investments to deliver Middle East LNG to the United States economically attractive as a long-term option. However, until such cost reductions occur, deliveries of Middle East LNG to the United States are more likely to be short-term in nature, occurring when surplus gas liquefaction and shipping capacity are available.

U.S. LNG Terminal Prospects

Figure 3.5 shows the locations of the four existing LNG terminal sites (a-d) and the 14 proposed "sites" for new LNG terminals. Three of the four existing terminals (Everett, Massachusetts, Lake Charles, Louisiana, and Elba Island, Georgia) currently receive LNG cargoes. The fourth terminal (Cove Point, Maryland) is expected to re-open in late 2002 or early 2003. Current annual capacity of the three active terminals is 1.6 Bcf/d. When Cove Point is opened, and planned expansions occur, capacity for the four existing terminals would reach 3.5 Bcf/d. Ultimately, their annual capacity could exceed 4 Bcf/d, about 6% of current U.S. gas supply.

Figure 3.5
New LNG Terminal Sites



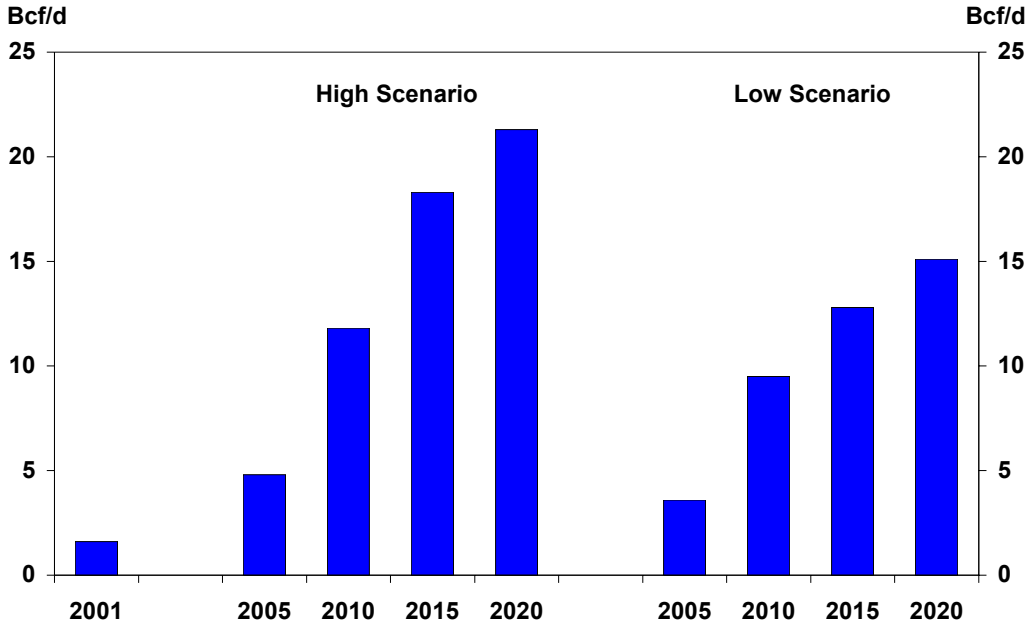
Some of the 14 proposed "sites" have more than one proposed project. For example, five projects have been proposed for the Baja California site, three for an Offshore Gulf of Mexico site, three in the Bahamas, and three in Northeast Mexico. *There are currently 26 active proposals at the 15 "sites*." In addition, some discussion has begun about a potential LNG terminal at Fall River, Massachusetts. Appendix A lists the four existing terminals and proposed projects at the 15 "sites" indicated in the figure.

The proposed capacity of the new terminals range from 500 MMcf/d (Tampa, Florida) to 1.5 Bcf/d (Hackberry, Louisiana). Given LNG economies of scale, "ultimate" (as opposed to initial) capacity at the proposed onshore or offshore platform sites that achieve operation are likely to be 1 Bcf/d or more. Currently, *three new sites* (Hackberry, Louisiana; Bahamas; and Baja California) *have a reasonable likelihood to achieve operation within the next 5-6 years*. In addition, El Paso projects that it would have up to four (4) offshore "terminals" using shipboard regasification by 2008 (1.6-2 Bcf/d capacity).

The number of new LNG terminals depends heavily on growth in lower-48 gas demand. If substantial growth in gas demand does not develop or appear likely within the next five years, then one or more of the three new sites likely to achieve operation in the next five years might be cancelled or delayed past 2010. After 2010, lower-48 and Western Canada gas production may top out. As a result, growth in U.S. gas demand would probably be carried largely by LNG or Alaska gas.

Figure 3.6 shows a range in LNG terminal capacity serving U.S. gas markets that could develop through 2020 in a world where U.S. gas consumption is on a track to reach 35 Tcf by 2020. The two LNG scenarios present a range of terminal capacity that would be expected to develop through 2020. The capacity that develops is expected to be found between this range.

Figure 3.6
U.S. LNG Terminal Capacity



In the **High LNG Import Scenario**, some new LNG terminal capacity becomes available in 2005. By 2010, LNG terminal capacity grows to 12 Bcf/d and 21 Bcf/d by 2020! In the **Low LNG Import Scenario**, new terminal capacity is not opened until after 2005. By 2010, LNG import capacity is approaching 10 Bcf/d; by 2020, it is 15 Bcf/d. The *critical uncertainty is the extent to which this LNG import capacity will be used*.

LNG Availability to U.S. Markets

In 2001, the United States imported less than 5% of world LNG supplies. From the perspective of proposed new LNG import terminals and gas demand growth in the United States, LNG imports should grow substantially in the future. As a result, the U.S. share of world LNG imports would surge. The growths in Figure 3.6 imply that the United States would be a major driving factor in the growth of LNG trade between 2001 and 2020. The extent to which this capacity would be utilized depends on availability of liquefaction and shipping capacity to U.S. LNG terminals.

World Liquefaction Capacity

Current world liquefaction capacity totals 121 million metric tons (MMt), almost 6 Tcf (16 Bcf/d). Within the next decade, liquefaction capacity could more than double. Liquefaction capacity can be allocated to four general, geographical regions.

- **Pacific Rim --** This region contains *half of existing world liquefaction capacity* (60.9 MMt), with almost all of this capacity in the East Indies area (Indonesia, Brunei, Malaysia, NW Australia). Liquefaction capacity may develop on the Pacific Coast of South America (Peru or Chile) and on Sakhalin Island in the next decade. Liquefaction capacity may also expand in South Alaska.

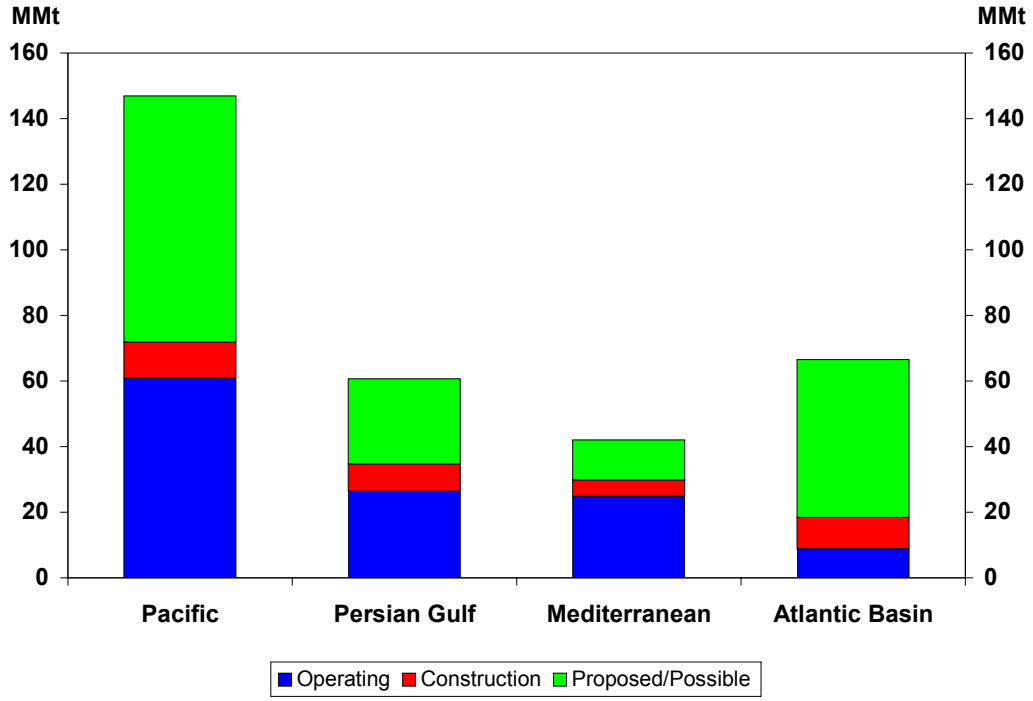
- **Persian Gulf** -- Liquefaction capacity (24.9 MMt) currently exists in United Arab Emirates (UAE), Qatar, and Oman. Liquefaction capacity is under consideration in Yemen.

- **Mediterranean** -- Liquefaction capacity currently exists in Algeria (22.4 MMt) and Libya (2.5 MMt). Liquefaction capacity is currently under construction in Egypt (5.0 MMt), with an expected completion date of 2004.

- **Atlantic Basin.** Liquefaction capacity (8.9 MMt) currently exists in Trinidad and Nigeria, and this capacity is expected to grow substantially in the next decade. Plans are active to develop liquefaction capacity in Norway, Venezuela, Angola, and Namibia.

Figure 3.7 allocates regional liquefaction capacity to three categories, existing, under construction (likely available before 2005), and proposed (could be available before 2010).

Figure 3.7
World Liquefaction Capacity



If all the facilities in Figure 3.7 reach operation by 2010, world liquefaction capacity would approach 320 MMt, more than 2.5 times current capacity. However, liquefaction capacity is unlikely to exceed 240 MMt by 2010. The Atlantic Basin, which currently has the least liquefaction capacity of the four areas, could have more liquefaction capacity by 2010 than the Mediterranean or the Middle East.

World LNG Shipping

In 2001, the LNG tanker fleet of 128 ships moved 5.2 Tcf. With firm orders for 64 ships scheduled to be delivered by 2006, and 20 options for additional LNG tankers, the LNG tanker fleet could be able to move more than 8 Tcf per year by 2006, more than most expected growths in world LNG trade through that period. A continuation of this pace of construction should be able to support a continued strong expansion of world LNG trade.

U.S. LNG Import Prospects

While less than 5% of world LNG supplies were delivered to the United States in 2001, that share should grow noticeably in the future. The growth in the U.S. share of world LNG supply, however, may have to compete against LNG demand in other countries, particularly in the near term.

Gulf and Atlantic Imports

LNG deliveries to the U.S. Gulf and Atlantic coasts will principally draw their long-term gas supply from Mediterranean and Atlantic Basin sources. Western Europe is the dominant market for LNG exports from Atlantic Basin/Mediterranean countries, currently taking almost 90% of their LNG output. In addition, new markets are expected to develop in Latin America (e.g., Caribbean, Brazil) that would also draw on Atlantic Basin LNG supply.

Because Western Europe and Latin America demand for Atlantic Basin/Mediterranean LNG will grow in the future, this implies that LNG output must grow quite rapidly to accommodate increased demand *from the United States, Latin America, and Western Europe*. As a result, U.S. demand may have to compete against Western Europe and Latin America (East "Coast") LNG demand, particularly through 2010.

Since the mid-1990s, annual growth in Western Europe LNG imports has been steady, averaging less than 70 Bcf/year (190 MMcf/d). Since the mid-1990s, LNG has provided about 14% of the increase in Western Europe gas demand, but that share has declined since the late 1990s. If the annual growth in Western Europe LNG imports increases to 110 Bcf/year (two thirds higher than the 1993-2001 average), LNG would provide 20% of the increased gas demand in Western Europe expected in the latest U.S. Department of Energy International Energy Outlook (IEO2002). By 2020, LNG would provide 13% of Western Europe gas supply, compared to an estimated 8% in 2001.

At 110 Bcf/year, Western Europe would compete strongly with U.S. LNG demand between 2000 and 2010. As a result, U.S. LNG imports into Atlantic and Gulf Coast terminals may not grow as rapidly as terminal capacity through 2010. After 2010, competition eases, and utilization of Atlantic and Gulf Coast terminal capacity would likely grow.

Pacific Imports

LNG deliveries to the U.S. Pacific Coast will principally come from Pacific Rim sources, such as the West Coast of South America, the East Indies, and possibly Alaska. Pacific Coast demand will compete against Asia and West Coast Mexico gas demand. Deliveries from the Middle East could go to any U.S. coast, but they are more likely to be short-term in nature, reflecting the availability of surplus LNG liquefaction and shipping capacity.

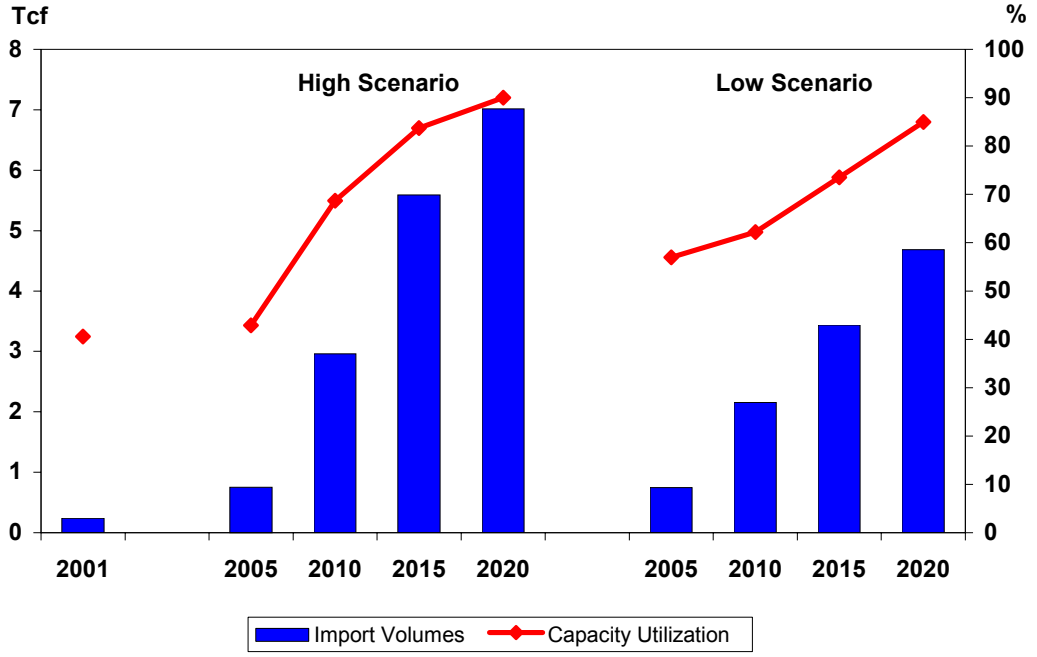
Asian gas markets have grown almost 200 Bcf/year since 1993, and that growth is likely to pick up in the future as large, new LNG markets develop in China and India. By 2010, annual LNG demand in Asia could be up 2 Tcf or more. Current plans to expand LNG capacity that would serve Asian

markets (Figure 3-7) substantially exceed this growth. If capacity currently under construction and only half the proposed capacity becomes operational by 2010, liquefaction capacity available to Asian markets would grow more than 3 Tcf, more than enough to accommodate the expected growth in Asian demand for LNG. As a result, LNG capacity on the U.S. Pacific Coast could run near (90%) capacity through 2010.

U.S. Import Scenarios

Figure 3.8 presents the outlook for LNG imports into the United States under the **High and Low LNG Import** scenarios. U.S. LNG imports include LNG delivered to Baja California and Bahamas terminals. The figure also shows utilization of U.S. LNG import terminal capacity trends presented in Figure 3.6.

Figure 3.8
U.S. LNG Imports and
LNG Terminal Utilization



In the **High LNG Import Scenario**, LNG imports reach 750 Bcf (2.1 Bcf/d) in 2005, 57% of available LNG terminal capacity. The low utilization rate reflects a combination of competition with Western Europe for LNG supply and normal build-up in capacity utilization as new terminals open. While competition with Western Europe remains strong between 2005 and 2010, LNG imports grow to 3.0 Tcf (8.1 Bcf/d) by 2010, and capacity utilization grows to 69%. Growth after 2010 averages more than 1 Bcf/d per year. By 2020, LNG imports reach 7.0 Tcf (19.2 Bcf/d), utilizing 90% of available LNG terminal capacity.

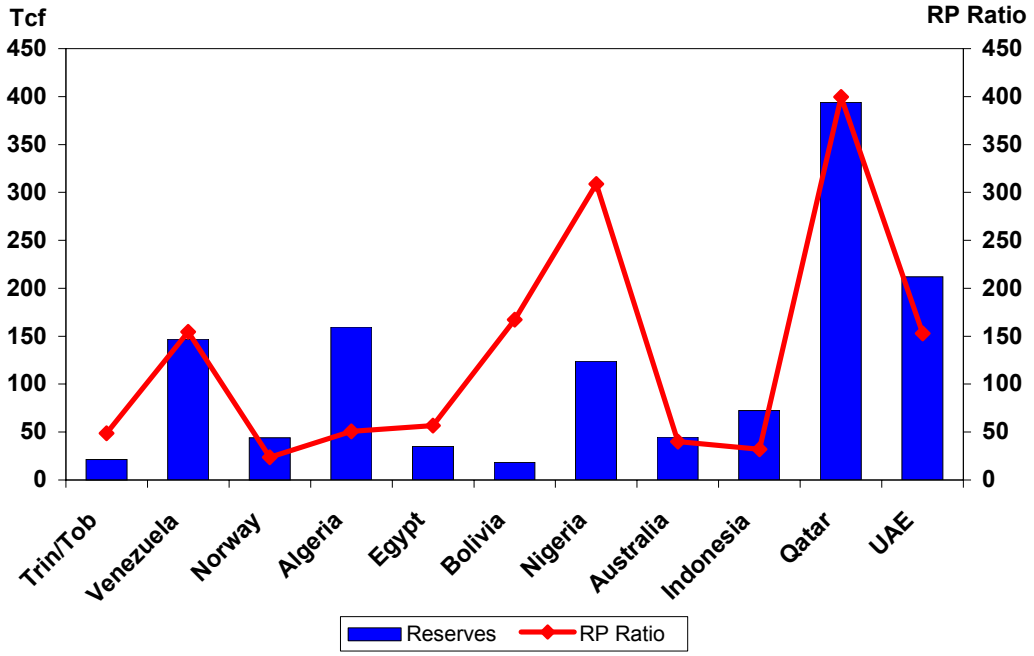
In the **Low LNG Import Scenario**, LNG imports reach 750 Bcf (2.1 Bcf/d) in 2005, 57% of available LNG terminal capacity. The *higher utilization rate* in this scenario is *because no new*

terminals begin operation until after 2005. LNG imports grow to 2.2 Tcf (5.9 Bcf/d) by 2010, and capacity utilization grows to 62%. Growth after 2010 averages 0.7 Bcf/d per year. By 2010, LNG imports reach 4.7 Tcf (12.8 Bcf/d), utilizing 85% of available LNG terminal capacity.

World Gas Supply

Most U.S. LNG imports will come from the Atlantic Basin and the Mediterranean, with some deliveries to the West Coast from South American or East Indies sources. Deliveries from the Middle East could occur, but mostly when there is surplus liquefaction and shipping capacity. Figure 3.9 presents the reserves and RP ratios in 2000 for the potential sources of LNG to the United States. The sources are arranged in order of their nominal distances from U.S. LNG terminals.

Figure 3.9
Reserves and RP Ratios
Potential U.S. LNG Sources



Gas RP ratios in 2000 ranged from a low of 24 in Norway to a high of 400 in Qatar. While more than half of the gas reserves in Figure 3.9 are in the Middle East, 550 Tcf is in the Atlantic Basin and Mediterranean. The average RP for Atlantic Basin/Mediterranean gas reserves in 2000 was 73. Other Atlantic Basin or Mediterranean countries, such as Angola and Libya, could become sources of LNG by 2020. If only 2% of current South Atlantic Basin/Mediterranean (i.e., Africa and Latin America) gas reserves were produced for export as LNG, these countries could export more than 10 Tcf per year. Therefore, from a reserves standpoint, LNG exports from Atlantic Basin/Mediterranean countries could accommodate the expected growth in U.S. LNG imports.

Figure 3.10 presents the impact of the **High LNG Import Scenario** *and* increased Western Europe LNG demand on gas reserves in Africa and South America. In this scenario, Western Europe and U.S. LNG imports exceed 10 Tcf in 2020 (compared to 1.4 Tcf in 2001) and are *solely* met by gas from Atlantic Basin and Mediterranean countries. The remaining Atlantic Basin/Mediterranean Basin reserves in 2020 are estimated based on the assumption that *no new gas reserves are added between 2000 and 2020*, an unlikely event. Because some Western Europe LNG imports may come from the Middle East and some U.S. LNG imports from Pacific Rim sources, this assessment probably overstates U.S./Western Europe/Latin America demand for Atlantic Basin/Mediterranean gas.

Figure 3.10
Basin/Mediterranean Gas Reserves
Draw-down: High Scenario

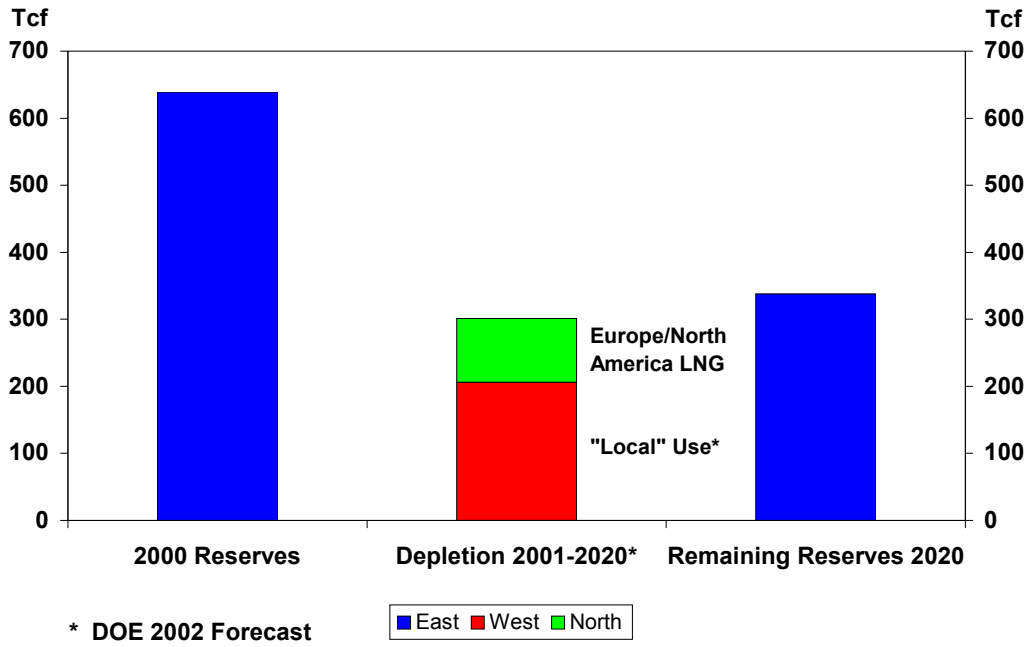


Figure 3.10 shows that the surge in LNG demand and increased local gas demand in Atlantic Basin and Mediterranean countries would only draw down about one half of the proved reserves as of year-end 2000 in **High LNG Import Scenario**. In this scenario, Atlantic Basin/Mediterranean gas production would exceed 27 Tcf (75 Bcf/d) in 2020. With 340 Tcf of remaining reserves at year-end 2020, the RP ratio would be 12.3. Because gas reserve additions will be made in the future, the aggregate RP ratio in the Atlantic Basin/Mediterranean countries would probably exceed 20 by 2020. While this is a substantial drawdown of the RP ratio from its current value of 80, this RP ratio could still support increased LNG exports and local demand after 2020. Therefore, *world gas reserves should be adequate to sustain a major growth in world LNG demand that, in large part, could be driven by increased LNG imports into the United States*.

Final Observations

U.S. LNG imports are likely to grow substantially in the coming years. By 2020, they may provide up to 20% or more of U.S. gas supply. This large growth in LNG imports will probably result in LNG becoming the marginal source of U.S. gas supplies. Thus, *U.S. gas prices will be increasingly set by world gas prices*, much in the same way that U.S. oil prices are currently set by the world oil prices.

Only about 25% or less of LNG prices in the United States since the mid-1990s reflects the cost to deliver the gas to the liquefaction plant gate (wellhead price plus pipeline tariff to liquefaction plant) in the exporting country. Because an aggressive expansion of world gas demand can be supported by current proved reserves outside North America, a rapid expansion of world LNG trade is unlikely to put significant upward pressures on world gas commodity prices through 2020. Given the likely decline in LNG facility costs over the next 20 years, *delivered LNG prices in the United States are not likely to show much growth and may even decline* unless some gas equivalent of OPEC develops *during the next 20 years*.

While long-term growth prospects for U.S. LNG imports are strong, near-term growth (through 2005) is likely to be relatively modest. The modest, near-term growth prospects in U.S. LNG imports reflects strong competition from Western Europe gas markets for access to Atlantic Basin and Mediterranean gas liquefaction capacity. This competition could be strong through 2010, particularly if the average, annual growth in Western Europe LNG imports picks up from its historical trends. If LNG growth remains near its historical level of 70 Bcf/year, however, opportunities improve for a rapid expansion of LNG imports into the United States from Atlantic Basin/Mediterranean countries, and U.S. LNG imports could approach 1 Tcf by 2005.

LNG imports into the U.S. Pacific Coast are unlikely to face severe competition from Asian markets. Some competition, however, may develop with Mexico for access to LNG, particularly if Mexico gas demand grows substantially faster than Mexico gas production.

Appendix A. North America LNG Terminal "Sites"

Map Legend	Terminal "Site"	Year	Capacity MMcf/d	Sponsors, Comments
a	Everett, MA	Open	535	Tractebel, expanding to at least 700 MMcf/d by 2005
b	Cove Point, MD	2002-3	750	Williams (could expand up to 1.2 Bcf/d)
c	Elba Island, GA	Open	440	El Paso, expanding to 800 MMcf/d by 2005
d	Lake Charles, LA	Open	700	CMS, expanding to 1.2 Bcf/d by 2005
1	St. John, NB	2005+	500	Irving Oil
2	Offshore Atlantic	NA	400+	**2 Proposals** El Paso Golar LNG
3	Bahamas	2005	800+	**3 Proposals** AES El Paso Enron
4	Tampa, FL	2005+	500	BP
5	Hackberry, LA	2006	1,500	Dynegy, applied for FERC approval May 30, 2002
6	Gulf of Mexico	2005	1,000+	**3 Proposals** ChevronTexaco CMS El Paso
7	Sabine Pass, TX	2007+	1,000+	Cheniere
8	Freeport, TX	2006	1,000+	Cheniere
9	Brownsville, TX	2006	1,000+	Cheniere
10	Altamira, Mexico	2005	700+	**3 Proposals** El Paso/Shell CMS Tractebel
11	Lazaro Cardenas, Mexico	2005+	800+	Tractebel (2 other West Coast Mexico sites possible)
12	Baja California	2005	750	**5 Proposals** Marathon Oil/Pertamina/Golar LNG/Grupo GGS El Paso/Phillips Sempra/CMS ChevronTexaco Shell
13	California	2005	500	**2 Proposals** ChevronTexaco El Paso
14	Mare Island, California	2007	1,300+	Shell/Bechtel

CHAPTER 4

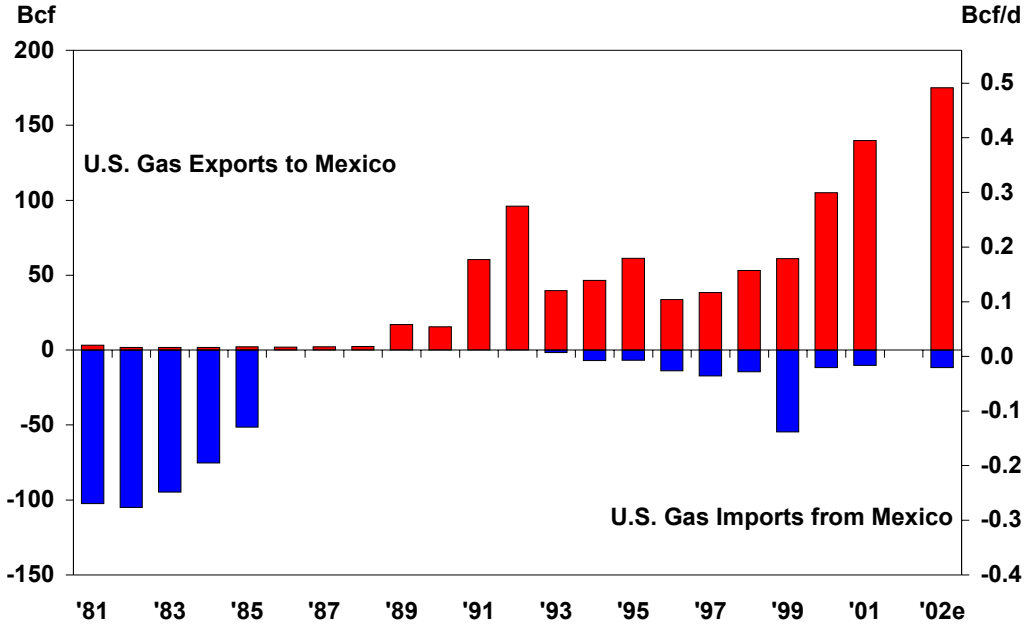
U.S.-MEXICO GAS TRADE

U.S.-MEXICO GAS TRADE

Introduction

The direction and size of U.S.-Mexico gas trade has varied substantially. Figure 4.1 shows U.S.-Mexico gas trade since 1981 with an estimate for gas trade in 2002 based on the first four months of the year. U.S. imports of gas from Mexico averaged more than 100 Bcf/year in 1981-82, and Mexico was then viewed as a significant future source of natural gas to the United States. From that peak, however, gas imports from Mexico fell off rapidly. *By 1985*, gas imports from Mexico had ended, and U.S.-Mexico gas trade was reduced to only about 2 Bcf/year of U.S. exports to gas markets in Sonora.

Figure 4.1
U.S. Mexico Gas Trade



U.S.-Mexico gas trade began to increase in 1989, but this time it was *growing exports from the United States to Mexico*. In the late 1990s, *U.S. gas exports grew substantially*, setting new records in 2000 and 2001. U.S. gas exports in 2002 are on a pace to exceed 160 Bcf for the year, another new record.

U.S. gas imports from Mexico resumed in 1993, coinciding with significant growth in Burgos Basin gas production. Since 1993, U.S. imports of Mexican gas have been modest, with the exception of 1999 when net U.S.-Mexico gas trade was almost balanced. The surge in U.S. imports of Mexican gas was a combination of continued growth in Burgos Basin gas production and a small decline in Mexico gas consumption. With the "recovery" in Mexican gas consumption and limited growth in Burgos gas production since 1999, U.S. imports of Mexican have averaged less than 10 Bcf/year.

The critical uncertainty is whether the recent surge in net gas flows South from the United States to Mexico indicates a long-term trend or is simply another periodic variation in U.S.-Mexico gas trade, reflecting the gas supply/demand balance in Mexico.

Because Mexican gas consumption is expected to grow substantially in the future, U.S.-Mexico gas trade may also increase. The direction and size of that flow, however, will depend on the future growth in Mexican gas demand and supply (domestic or LNG imports), and could have a significant impact on gas supply and prices in the United States.

This chapter will assess the outlook for U.S.-Mexico gas trade in the future and whether *Mexico* will be a *source or consumer of gas supply in the United States*. Specifically, this chapter will:

- review the current market context of Mexican gas consumption
- assess prospects for Mexican gas consumption
- assess prospects for increased Mexican gas supply
- discuss implications for U.S.-Mexico gas trade.

The data used in this chapter are taken from the U.S. Department of Energy, Energy Information (EIA) international energy data. While EIA and Pemex data start from the same wellhead production data, EIA gas production and consumption for Mexico currently run about 500 MMcf/d below reported Mexican production data, from which Pemex derives its supply/demand balance. This difference is because EIA production excludes some field "losses". Pemex data include these "losses" in both the supply and consumption ends of the balance. Therefore, both data sets are consistent; they are just measured from different points.

Mexican Gas Market Context

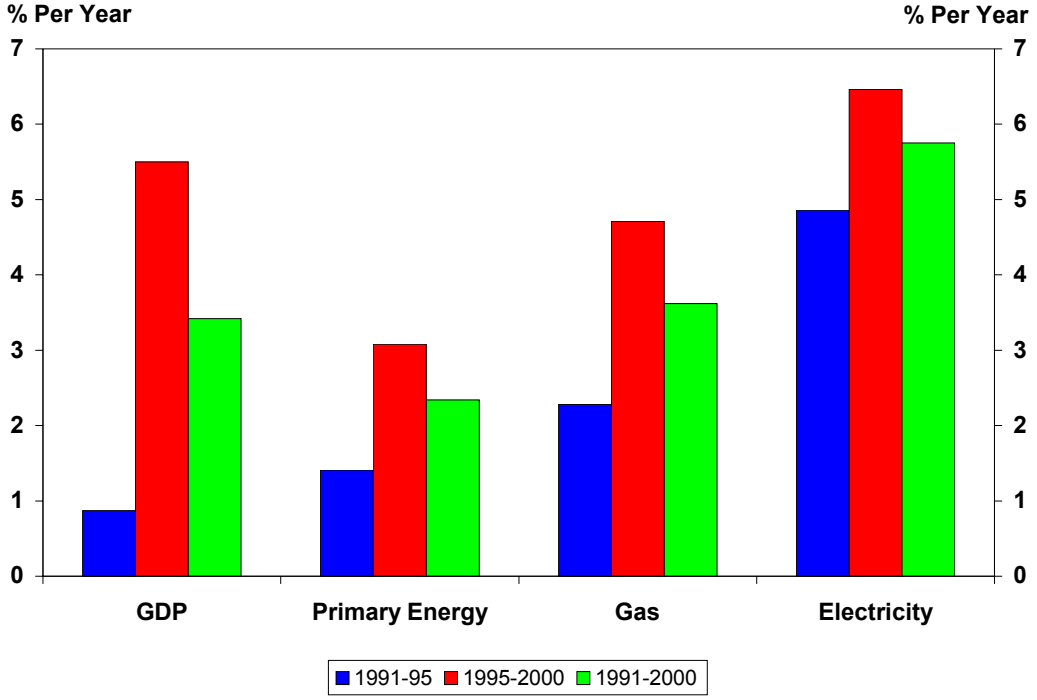
Table 4.1 compares energy consumption data in North America (Mexico, United States, and Canada). While Mexican energy consumption is substantially less than U.S. and Canadian energy consumption, the gas share of primary energy consumption is relatively consistent in all three countries. Therefore, the *low level of Mexican gas consumption reflects the low level of total Mexican energy consumption, not a small aggregate market penetration by gas*. If Mexican gas consumption grows substantially in the next 20 years, it implies a gas share of Mexican primary energy consumption that will probably be much higher than in the United States or Canada. The critical question is whether such a rapid growth would be plausible.

Table 4.1
North America Energy Consumption in 2000

	Mexico	United States	Canada
Primary Energy (quads)	6.2	98.8	13.1
Gas Consumption (quads)	1.5	23.1	3.4
Gas Share	23.6%	23.4%	25.8%
Electricity (10^9 kwh)	183	3,621	500

Figure 4.2 presents the growth rates for Mexico's GDP plus primary energy, gas, and electricity consumption since 1991. Growths are presented for the period of economic doldrums (1991-95), rapid economic growth (1995-2000), and the entire period (1991-2000). During the economic doldrums period, all three energy types grew more rapidly than reported GDP. However, when economic growth picked up after 1995, only electricity grew more rapidly than GDP.

Figure 4.2
Mexico Average Annual Growths



Primary Energy. Primary energy consumption in Mexico grew 23% between 1991 and 2000. Most of that growth occurred after 1995, when the Mexico's economic activity came out of its early 1990s doldrums.

Gas. Gas consumption 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% in 1991 to almost 24% in 2000. Most of the increased share occurred after 1995.

Electricity. Electricity generation accounts for about one third of primary energy consumption in Mexico, less than the 40% or more in the United States or Canada. *Electricity consumption* in Mexico *grew more than twice as fast* as growth in primary energy demand during the 1990s. Even during Mexico's economic doldrums between 1991 and 1995, electricity consumption grew 4.9% per year. Between 1995 and 2000, electricity consumption grew 6.5%.

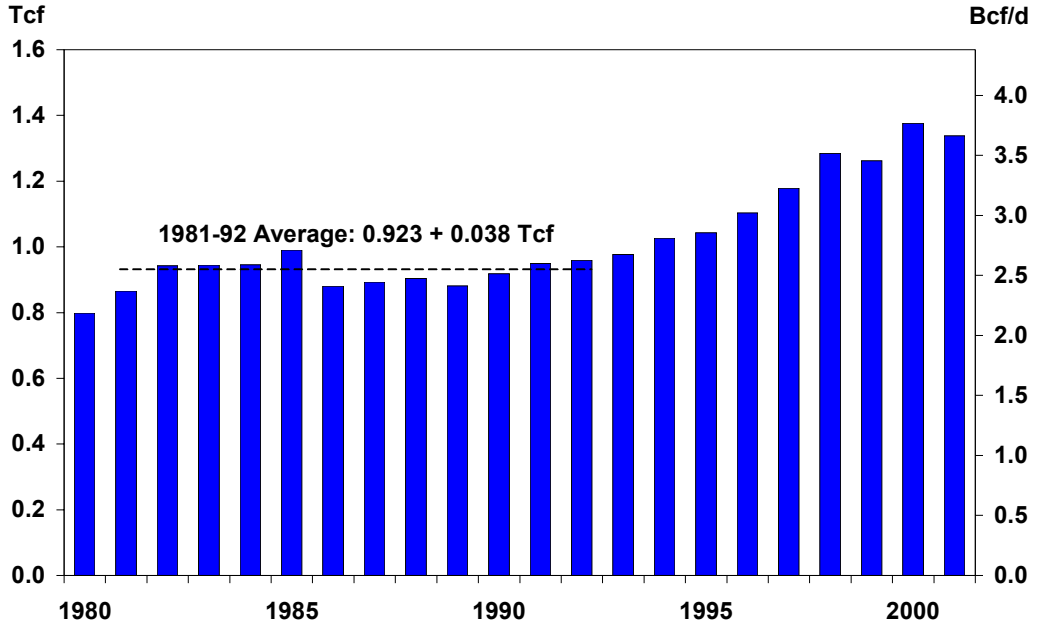
Currently, *most Mexican electricity is generated by oil, but most proposed new electricity generation capacity is gas-fired*. In addition, a significant amount of existing oil-fired electricity generation

capacity will be converted to gas. As a result, the demand for gas in Mexico should surge as new gas-fired generation comes on line.

Mexican Gas Prospects

Figure 4.3 presents the trend in Mexican gas consumption since 1980. Mexican gas demand showed essentially no growth between 1981 and 1992, averaging 0.9 Tcf/year (2.5 Bcf/d). While the Mexican economy reported essentially no growth between 1981 and 1988, growth resumed in 1989, and continued through 1992. Mexican gas demand, however, did not begin to grow until 1993, when the Mexican economy had once again returned to the doldrums. Thus, the linkage between the growths in Mexican GDP and gas consumption has been weak.

Figure 4.3
Mexico Gas Consumption



Since 1992, Mexican gas consumption has increased, but 85% of that increase occurred by 1998. Since 1998, Mexican gas consumption has only increased 150 MMcf/d. Mexican gas consumption in 2001 is estimated to exceed 1.3 Tcf (3.7 Bcf/d).

Two scenarios for future Mexican gas consumption are developed. They reflect differing expectations for Mexican gas demand and Mexican gas supply, and are developed to bracket a range of prospects for increased Mexican gas demand and gas production over the next 20 years.

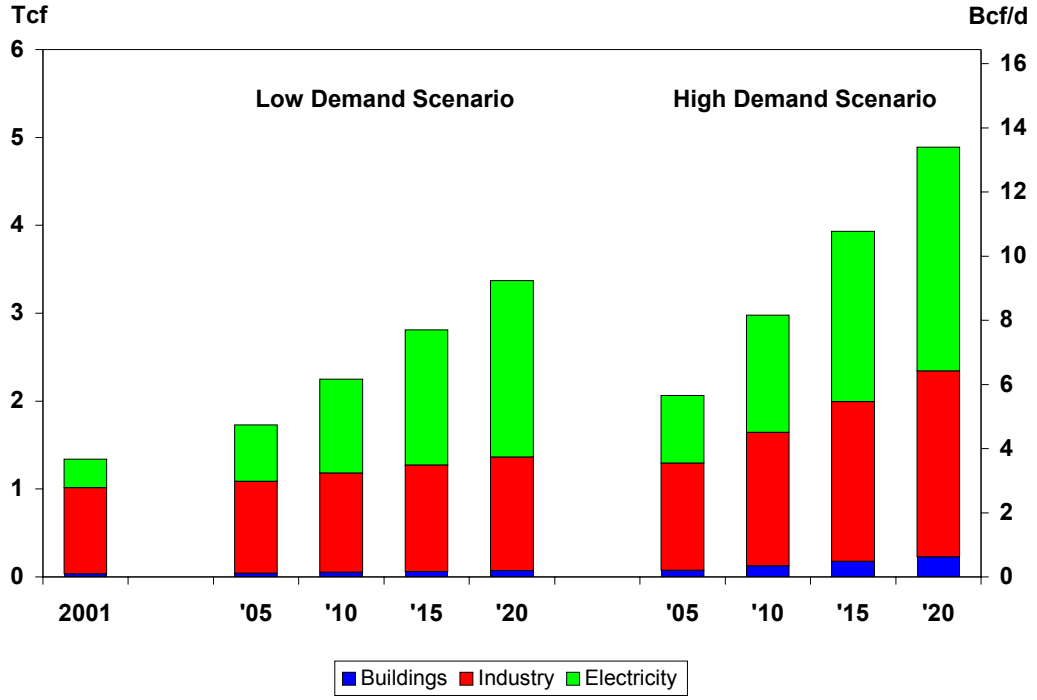
The **High Demand Scenario** expects that Mexican economic growth resembles its average rate since 1995 (> 5%/year), consistent with Mexican government forecasts. In this scenario, plans to rapidly expand Mexican gas production are successful, and Mexican gas supply grows significantly. Despite this domestic supply success, imported gas plays a growing role in Mexican gas supply.

The **Low Demand Scenario** is more consistent with average trends since 1991 and thus reflects the effects of economic cycles *and* limited near-term growth in Mexican gas production. It is, however, more optimistic than the most recent EIA International Energy Outlook (2002). While efforts to expand Mexican gas supply are successful, growth in Mexican gas production does not become significant until near 2010. As a result, most of the growth in near-term Mexican gas supply for this scenario relies on increased gas imports from the United States or overseas as LNG.

Mexican Gas Demand Prospects

Figure 4.4 presents the outlook for Mexican gas demand in the two scenarios. Demand is allocated to buildings (residential/commercial), industry, and electricity generation. Industry gas consumption includes Pemex consumption. The allocations are based on Mexican government data.

Figure 4.4
Mexico Gas Consumption



In the **Low Demand Scenario**, Mexican gas consumption doubles by 2015 and reaches 3.4 Tcf (9.2 Bcf/d). In this scenario, Mexican gas consumption grows 5.9%/year between 2001 and 2010 and 4.1% per year between 2010 and 2020. While buildings consumption more than doubles in this scenario, its share is only 2%.

Industrial gas consumption is currently the largest gas market in Mexico, accounting for 73% of Mexican gas consumption in 2001. Its growth, however, is projected to be relatively modest through 2020, about half the rate expected by the Mexican government. Between 2001 and 2020, it increases only 315 Bcf (860 MMcf/d). By 2020, industry only accounts for only 38% of Mexican gas consumption.

Gas consumption for electricity generation surges between 2001 and 2020, increasing more than six times. Shortly after 2010, it becomes the largest gas market in Mexico. By 2020, it accounts for 59% of Mexican gas consumption.

In the **High Demand Scenario**, Mexican gas consumption doubles before 2010 and reaches 4.9 Tcf (13.4 Bcf/d) by 2020. In this scenario, Mexican gas consumption grows 9.3%/year between 2001 and 2010 and 5.1%/year between 2010 and 2020. Buildings consumption more than doubles in this scenario by 2005 and doubles again after 2010. By 2020, buildings consumption has increased almost sevenfold above its 2001 level, accounting for 5% of Mexican gas consumption in 2020.

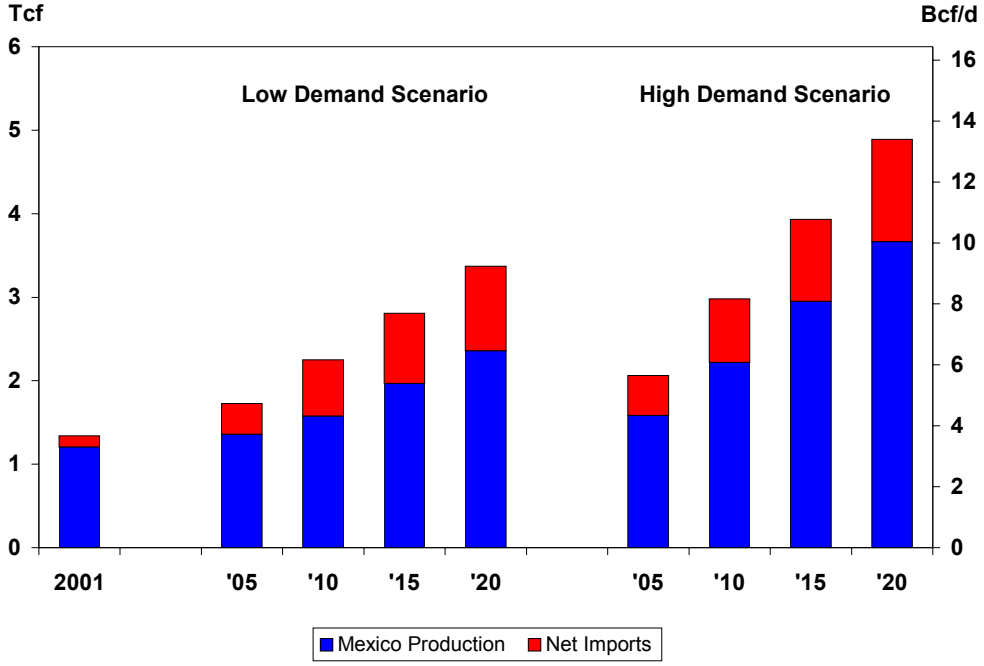
Gas consumption by *industry* more than doubles in this scenario between 2000 and 2020, increasing 1.1 Tcf (3.0 Bcf/d). Despite this more rapid growth, its share of Mexican gas consumption shrinks to 43% by 2020.

Gas consumption for electricity generation surges even more in this scenario, increasing almost eightfold between 2000 and 2020. Because of the larger growth of industrial gas consumption in this scenario, electricity generation does not become the largest gas market in Mexico until almost 2015. By 2020, it accounts for 52% of Mexican gas consumption.

Mexican Gas Supply Prospects

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% of Mexican gas supply*** came from the ***United States***. Figure 4.5 presents the outlook for Mexican gas supply in the two scenarios. Supply is allocated to Mexico gas production and net imports. In both scenarios, net imports are expected to continue to play a growing role in Mexican gas supply.

Figure 4.5
Mexico Gas Supply Sources



In the **Low Demand Scenario**, Mexican gas production grows 3% per year between 2001 and 2010, reaching 1.6 Tcf (4.3 Bcf/d) by 2010. This is almost double the observed growth rate since 1997, but less than half the rate forecast in current Pemex plans. This slower growth rate implies that development of new gas producing areas in Mexico takes longer than current Pemex plans. Imports grow substantially between 2001 and 2010. By *2010, net imports* into Mexico reach 0.7 Tcf (1.8 Bcf/d), *five times their 2001 level*. Between 2001 and 2010, imports provide *60% of the increased gas supply* in Mexico. By 2010, imports provide 30% of Mexican gas supply, compared to 10% in 2001.

The growth in Mexican gas production picks up after 2010, averaging 4.1% per year between 2010 and 2020. This reflects continued success in the Burgos Basin and opening of new producing areas in Mexico. The growth in Mexican gas production matches the growth in Mexican gas consumption after 2010, thus maintaining its share of total supply at 70%. By *2020, Mexican gas production* is 2.4 Tcf (*6.5 Bcf/d*), *almost double current production levels*. Net imports continue to grow after 2010, reaching 1.0 Tcf (2.8 Bcf/d) by 2020.

In the **High Demand Scenario**, efforts to expand production have significant near-term success. Between 2001 and 2010, Mexican gas production grows 7%/year or 1.0 Tcf (2.8 Bcf/d), reaching 2.2 Tcf (6.1 Bcf/d) in 2010. Despite this rapid growth in domestic gas production, imports provide a growing share of Mexican gas supply. By *2010, net imports into Mexico* are 0.8 Tcf (2.1 Bcf/d), *25% of Mexican gas supply*, consistent with Mexican government expectations.

Efforts to expand Mexican gas production continue to be successful after 2010, but the average annual growth rate slows to 5.1% per year. Given current Pemex expectations for the Burgos Basin, this implies additional successes in the Burgos Basin *and/or* development of new producing areas. Although growth in Mexican gas production slows after 2010, it keeps pace with growing Mexican gas consumption, thus maintaining its share of total supply at 75%. By *2020, Mexican gas production* is 3.7 Tcf (*10.0 Bcf/d*), *triple 2001 production*. Net imports reach 1.2 Tcf (3.3 Bcf/d) by 2020.

Implications For U.S.-Mexico Gas Trade

Mexican government plans expect that net imports will play a growing role in Mexican gas supply. While imports currently come from the United States, LNG is likely to become the dominant player in Mexican gas imports in the next decade. In fact, LNG may totally replace the role of U.S. gas supply in the Mexican gas market.

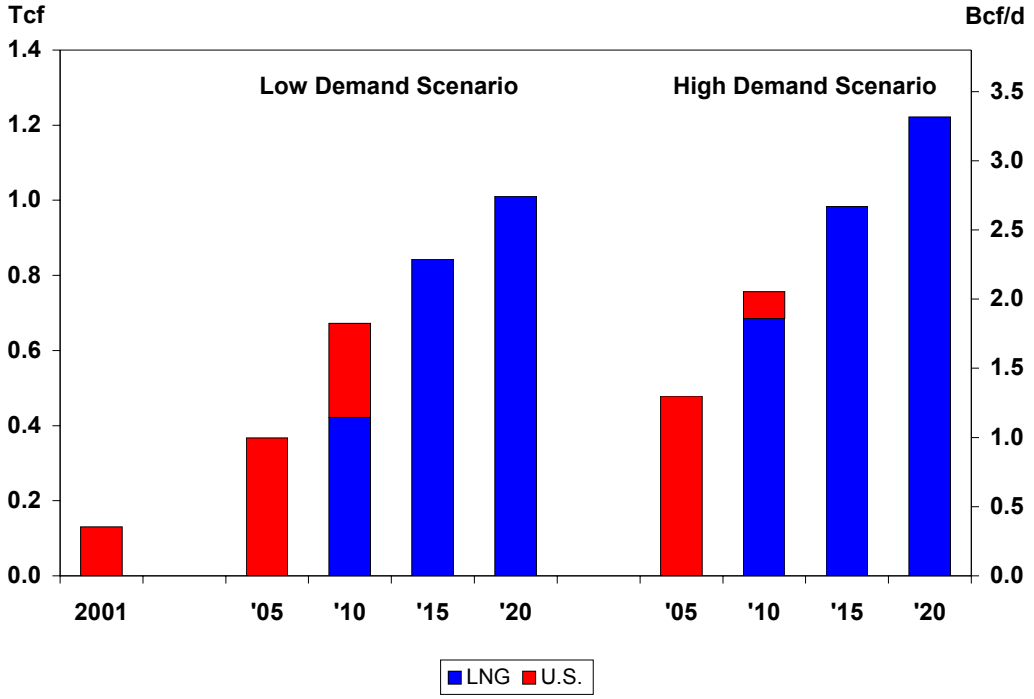
Currently, five LNG terminals have been proposed for Mexico. Two (one at Altamira, Tamaulipas and the other in Baja California) are quite far along in planning and could begin operation within the next 5-6 years. The other terminals would be along the Mexican Pacific Coast. Figure 4.6 indicates the locations of these proposed terminals.

Figure 4.6
Mexico Proposed LNG Terminals and Pipelines

The Altamira terminal is directed at the Mexican gas market, but most of the gas delivered to a Baja California terminal is likely to be delivered to California by pipeline or by wire (as electricity). A Lazaro Cardenas or other Pacific Coast terminal would help develop significant gas markets in Western Mexico and could also provide gas to Central Mexico markets.

Until LNG imports begin, the United States would supply any increased demand for gas imports by Mexico. Figure 4.7 allocates Mexican gas imports to U.S. and overseas (LNG) sources for the two scenarios. In the **Low Demand Scenario**, LNG imports begin in 2006, and two terminals (Baja California and Altamira) are opened by 2010. A third (Lazaro Cardenas) is opened after 2010. In the **High Demand Scenario**, LNG imports begin in 2006. Three terminals (Baja California, Altamira, and Lazaro Cardenas) are opened before 2010, and an additional Pacific Coast terminal after 2015.

Figure 4.7
Mexico Gas Imports Sources



In the **Low Demand Scenario**, *Mexico imports* (net basis) 370 Bcf (1.0 Bcf/d) of gas from the United States in 2005, almost *triple its 2001 level* of 130 Bcf (355 MMcf/d). With the opening of two LNG terminals, the growth in demand for gas imports from the United States slows, and then declines. By 2010, Mexico only imports 250 Bcf (680 MMcf/d) from the United States. With the opening of a third terminal after 2010, demand for U.S. gas imports by Mexico is largely over on a net annual basis.

In the **High Demand Scenario**, Mexico imports (net basis) 480 Bcf (1.3 Bcf/d) of gas from the United States in 2005, more than triple its 2001 level. With the opening of three LNG terminals before 2010, demand for gas imports from the United States tails off sharply. By 2010, demand for U.S. imports is less than 100 Bcf, and the opening of a fourth terminal allows LNG to meet increased Mexican demand for gas imports without any net annual gas imports from the United States. In fact, some LNG deliveries to non-Baja terminals might find its way North into the United States (Texas/Tamaulipas) after 2010.

Final Observations

Principally because of a need to supply a rapidly electricity growing demand in Mexico, Mexican gas demand is likely to grow 300-500 MMcf/d or more per year over the next 20 years. Unless a world-scale gas field, play, or basin beyond current Pemex 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 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 Bcf/d*. If U.S. gas supplies remain tight in the near-term, this increased gas demand from Mexico would put upward pressures on gas prices.

With the opening of new LNG terminals in Mexico after 2005, Mexican demand for U.S. gas supply will begin to tail off. By 2010, less than half of Mexican gas imports will come from the United States. The pace at which U.S. gas exports to Mexico tail off after 2010 will depend heavily on the timing of the opening of a third LNG terminal in Mexico.

After 2015, net annual imports of gas by Mexico from the United States will likely be essentially over. In fact, some modest gas volumes (net annual basis) may begin to flow back from Northeast Mexico into Texas, about 2015, particularly if a fourth terminal begins operation. Therefore, *the recent surge in net U.S. gas exports to Mexico should last through much of the decade, but after 2010, net U.S. gas exports are likely to be essentially over.*

CHAPTER 5

GAS HYDRATES

GAS HYDRATES

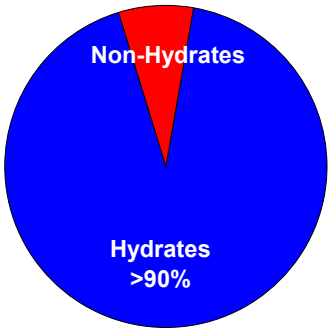
Introduction

Natural gas hydrates are a type of clathrate (i.e., a compound of methane and natural gas liquids held inside a solid, crystalline lattice of water). The presence of natural gas stabilizes the host structure (ice) above its normal melting point at a particular pressure. Three types of gas hydrate structures have been identified:

- *Type I*, which contains methane and ethane
- *Type II*, which can also contain propane and iso-butane
- *Type H*, which can also hold iso-pentane.

Gas hydrates first came to the attention of the gas industry in the 1930s, when they were identified as the cause of ice-plugging in some pipelines. In the 1960s, they were recognized in some wells drilled in Arctic regions. Before 1992, the Ocean Drilling Program (ODP) avoided areas of suspected gas hydrates because of the potential risk of a blowout. Since 1992, however, hydrate deposits have been the target of many ODP wells to evaluate their magnitudes and locations.

Global Gas Resource



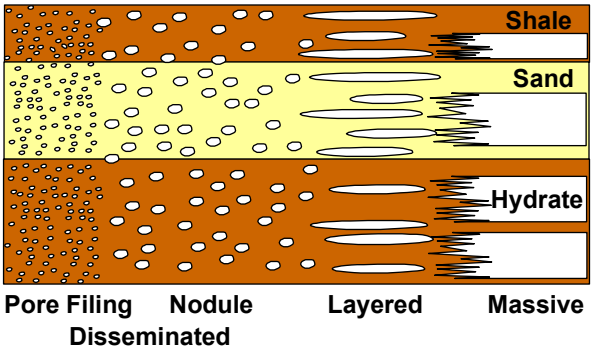
While estimates of global gas *hydrate resources* have varied greatly, they *dwarf estimates of all other natural gas resources combined*. Recent estimates of gas-in-place volumes trapped in hydrates range from 100,000 to 1,000,000 Tcf. As more data are gathered, the range should narrow.

If only 5% of the hydrate resource were recoverable, it would exceed estimates of recoverable gas from non-hydrate sources. However, *gas production from hydrates is not economic using current technology*. This chapter will review hydrate resource prospects and the current status of production technology. Based on this review, prospects for hydrate production will be discussed.

Hydrate Resource Prospects

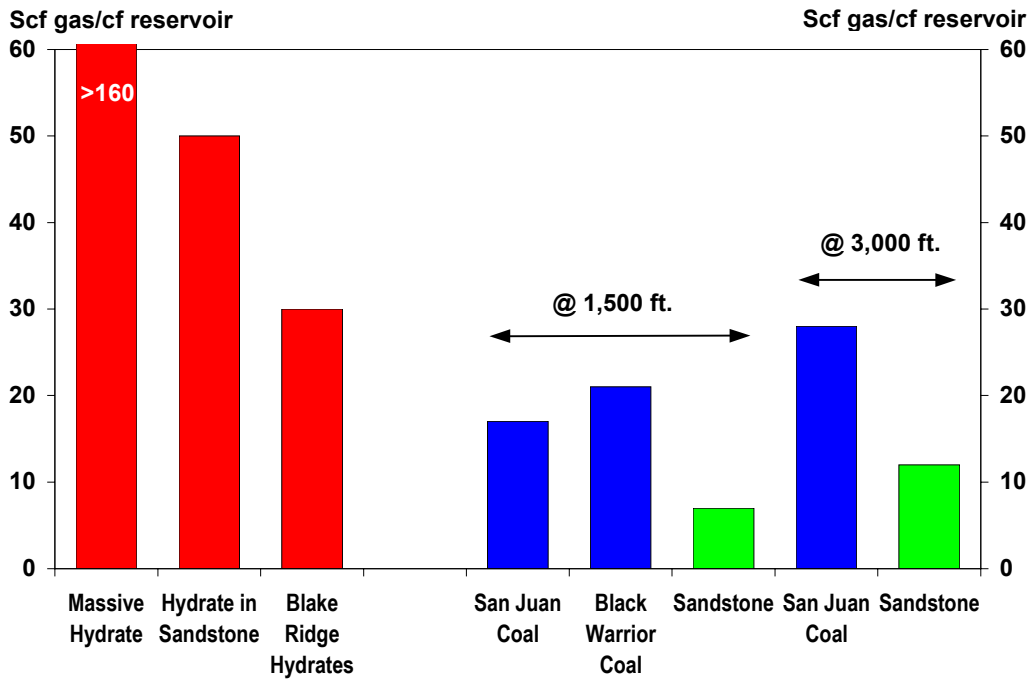
Hydrates can be found in a variety of geological conditions. In order of increasing continuity, their physical forms within sediments are pore filling, nodular, layered, and massive. In the Gulf of Mexico they even occur on the sea floor, associated with natural gas seeps.

Hydrate Forms



The storage capacity of gas hydrates is compared with sandstone and coal in Figure 5.1. Gas storage capacity is presented in terms of standard cubic feet (scf) of natural gas per cubic foot (cf) of reservoir rock volume. Three hydrate cases are presented. The largest concentration is for a massive distribution; the second is for a pore-filling hydrate in sandstone, such as those found in the Arctic; and the third is for hydrates observed in the silts and clays at Blake Ridge. The Blake Ridge deposit, which is estimated to contain up to 1,300 Tcf, is about 200 miles offshore North Carolina.

Figure 5.1
Gas Storage Capacity



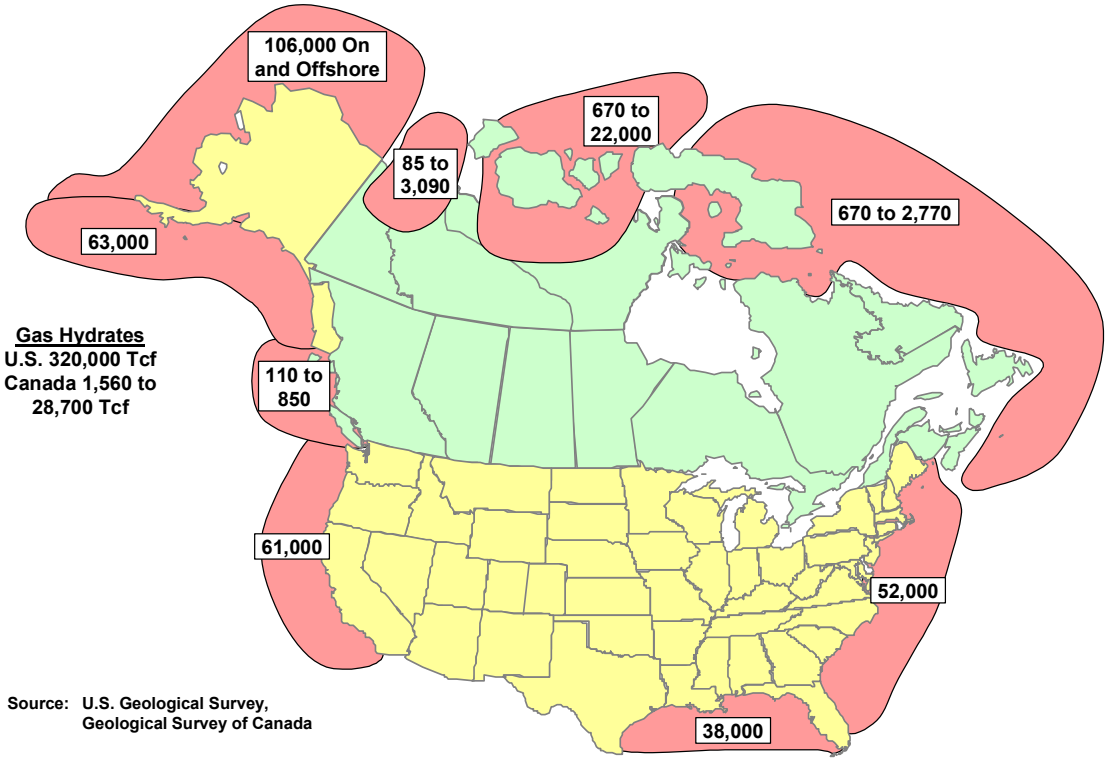
Source: GRI (1989)
Sandstone: Porosity = 25%, Water Saturation = 30%

Figure 5.1 shows that gas storage capacity for *massive* hydrate deposits can be more than an order of magnitude larger than conventional sandstone reservoirs. Hydrates at Blake Ridge have more gas storage capacity than coal seams. Given these concentrations, it is understandable how hydrate gas-in-place estimates can be so large.

Gas hydrates are found around the world in outer continental shelf (OCS) sediments in water depths greater than 500 meters, where temperatures are only a few degrees above freezing, and in polar (permafrost areas) sediments. The Hydrate Stability Zone (HSZ), where gas hydrates are stable, ranges from a few meters to more than 1,000 meters thick, depending on temperature, pressure, geothermal gradient, gas volume, and gas composition. These factors also control the depth at which the HSZ begins.

Hydrates have been identified in offshore sediments surrounding North America as well as in the northern continental permafrost regions. Figure 5.2 presents the published U.S. Geological Survey (USGS) and the Geological Survey of Canada (GSC) estimates of the gas hydrate resources in North. The USGS estimate totals 320,000 Tcf. The more recent (2001) GSC estimates incorporate the latest knowledge of hydrate distribution, and concentration, and are more conservative ranging from 1,560-28,700 Tcf.

Figure 5-2
Undiscovered Gas (Tcf)



The Canadian gas hydrate resource estimates are based on seismic data indicating the presence and thickness of hydrates. However, significant uncertainty surrounds the interpretations of the seismic data. Because most seismic is shot exploring for deeper oil and gas pools, it is not optimized for the shallow depths of the HSZ. In addition, the seismic signal frequencies are not optimum for the detection of hydrates. The ODP has also identified hydrates where no seismic character was present. A recent re-evaluation of the USGS estimates using ODP data suggests that the USGS estimate should be reduced about 40% to about *200,000 Tcf*, still a massive resource.

While the lower-48 hydrate resource may exceed 100,000 Tcf, most of the lower-48 hydrate resource is in areas (Offshore Atlantic, Eastern Gulf, Offshore Pacific) where development is currently precluded. Only the hydrate resource in the parts of the Gulf of Mexico currently open to drilling could be developed. Nevertheless, if only about 5% of the hydrate gas-in-place resource estimate for the Gulf of Mexico were recoverable, more than 1,000 Tcf of gas could be produced from Gulf of Mexico hydrates.

Production Prospects

Production from gas hydrates is claimed to have occurred at Messoyakha, the first producing gas field in the West Siberia basin. The field was discovered in 1964 and began production in 1969. The field has produced 508 Bcf, and 36% (183 Bcf) may be from the hydrates which cap the field. Recent studies, however, have questioned whether most of this gas is actually coming from hydrates.

On the North Slope of Alaska, a shallow gas hydrate deposit above the Prudhoe Bay and Kuparuk River oil fields is estimated to *contain 37 to 44 Tcf* of gas-in-place. This hydrate deposit has been penetrated by many wells developing the underlying oil fields, but it was also the target of one evaluation well. This well was cored and produced gas from the hydrates. It was tested with a flow rate of *4 Mcf/d* (similar to production rates reported for hydrate zones at Messoyakha).

A consortium, including the USGS, the Japan National Oil Company (JNOC), led by the GSC, and operated by the Japan Petroleum Exploration Company (JAPEX), drilled the first Arctic gas hydrate test well in 1998 at Malik 2L-38 on Richards Island in the Canadian Mackenzie Delta. Early in 2002, the well was stimulated with hot water and production tested. The flowed gas was flared. Details of the test have been held confidential, according to the terms of the consortium agreement.

Production Technology

Hydrates are very impermeable, and thus can act as a reservoir seal, trapping free gas beneath them, as they have at Kuparak and Messoyakha. Offshore, many hydrates are contained in impermeable clays and low permeability silts. As a result, *direct production of gas from hydrates will probably need stimulation to dissociate the gas from the hydrate* ***and*** *create a path for the gas to move to the well bore*.

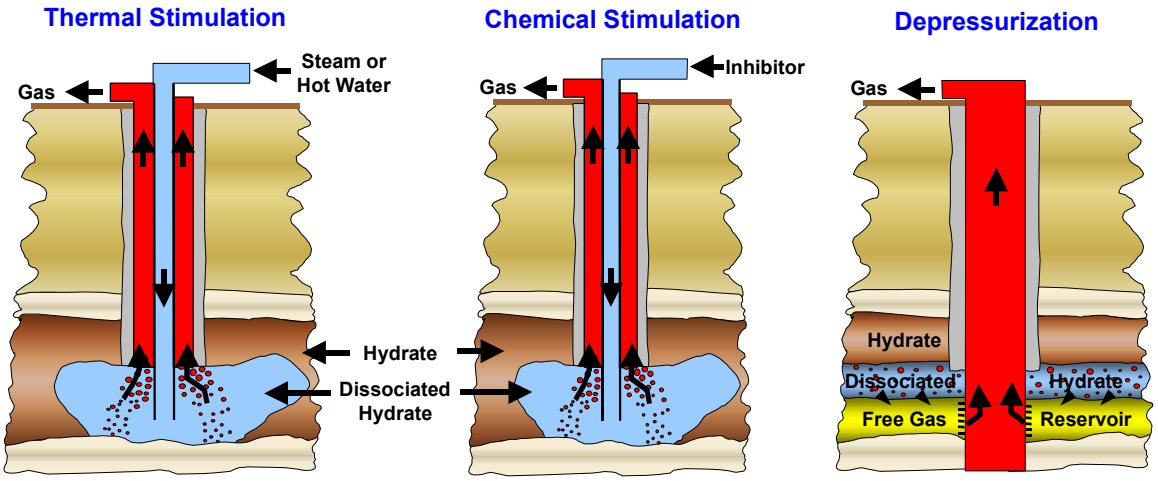
Figure 5.3 illustrates three proposed production mechanisms:

- **Depressurization**, the process attributed to late-stage production at Messoyakha, is the *lowest cost* process, and has been demonstrated to be technically feasible. Production results, however, suggest that this "natural" process is *unlikely* to be *economic without further technology advance*.

- **Thermal Stimulation** introduces heat into the reservoir by direct stimulation (electric or sonic) or by injection of steam or heated water.

- **Chemical Stimulation** could employ processes currently in use to prevent hydrate formation during gas production, processing, or transportation.

Figure 5.3
Potential Production Mechanisms



Computer model simulations of thermal stimulation processes in gas hydrates show that gas flow is possible, but that initiating and maintaining the flow paths will be a challenge. Because dissociation is an endothermic (requires energy input) reaction, flow paths may become restricted by ice formation or even by hydrate re-formation in the host formation. In addition, the energy injected into the hydrates must be kept small compared to the natural gas energy produced from the hydrates.

The high degree of uncertainty over production mechanisms, and gas flow rates from hydrates, makes any evaluation of costs and economics highly speculative. The National Petroleum Council (NPC) in their 1992 report natural gas report made some initial estimates of potential hydrate costs that might develop after some technology advances. Table 5.1 compares costs and resulting gas wellhead prices to a nominal conventional well.

Table 5.1
NPC Economic and Technical Well Assumptions

	Depressurization	Thermal Stimulation	Conventional Gas
Capital Cost (US$ Millions)	3.3	5.1	3.2
Annual Cost (US$ Millions)	2.5	3.2[1]	2
Rate(MMcf/d)	3	2.5	3
Wellhead Price ($/Mcf)	2.80	4.50	2.00

[1] 30,000 Bbl/d hot water injected

Hydrate production costs might be reduced in areas of conventional production, by using deep-sourced, hot-formation water and re-completed wells that would otherwise be abandoned at the end of their conventional production life. The critical question, however, will be production rates from hydrate wells. Currently, depressurized processes appear to produce of only a few Mcf/d. Therefore, the *critical issue* for hydrate production may be *more increasing production rather than reducing costs*.

Current Research

In the United States, the Methane Hydrate Research and Development Act, signed in May 2000 initiated the National Methane Hydrate program led by the U.S. Department of Energy, with authorization to spend US$47.5 Million over five years. The research is focused on resource assessment and development of drilling technologies to reduce the risk of drilling through natural gas hydrates.

In addition to the Malik project discussed previously, Japan is evaluating gas hydrates in the Nankai trough off the coast of Japan. An offshore hydrate test well was drilled in 1999, and Japan is targeting commercial production from hydrates in 2016. Other countries, such as India, Germany and Norway, are also researching hydrates.

Hydrate Production Prospects

The current hydrate situation may be analogous to coalbed methane 20-25 years ago, when it was sometimes dismissed as "moonbeam" gas. While research substantially reduced coalbed methane investment and operation costs, the most critical advance was substantially increasing coalbed methane production with limited increases and often decreases in capital and operating costs.

The challenge to develop *economic gas production from hydrates* is to *initiate and maintain flow paths within a "hydrate" reservoir at a competitive price*. Because of its lower cost, depressurization is a likely initial production option, but current depressurization applications result in very low gas flow rates. The rates in Messoyakha and Alaska appear to be on the order of a few Mcf/d. The 1992 NPC study indicated that production rates from hydrates had to be on the order of many MMcf/d for hydrate production to even be marginally uneconomic. The high unit operating costs of thermal or chemical stimulation mean that hydrates are unlikely to compete economically with high flow-rate, conventional frontier gas wells unless gas hydrate production rates are much higher and/or can be sustained at high rates for a substantial period of time.

Current estimates of the hydrate resource base are 320,000 Tcf in the United States and perhaps as high as 30,000 Tcf in Canada. However, most of this hydrate resource would face severe economic or institutional barriers. *More than half of U.S. hydrate resources and 90% of Canadian hydrate resources are in Arctic or near-Arctic remote locations*, where gas wellhead prices would have to be quite low for gas from hydrates to be a competitively priced gas source in North American or world gas markets. In addition, more than one third of the U.S. gas hydrated resource is in offshore lower-48 areas that are currently closed to exploration. Therefore, *only* about *10% of the total hydrate*

resource in North America can be currently considered a *reasonable resource prospect in the next 20 years*, and even this part of the hydrate resource will require significant technical advances to be economically attractive. Nevertheless, even this small share of the total hydrate resource would provide a significant boost to North American gas supply if technical advances can make it economically and technically feasible to develop.

At this point, significant commercial hydrate production is unlikely to occur through the mid-term. Even the relatively aggressive Japanese program does not expect commercial production from hydrates until 2016. Thus, hydrates may at best be only a small, marginal source by 2020. But, who would have thought 20-25 years ago that coalbed methane production would be where it is today.

CHAPTER 6

GAS-TO-LIQUIDS

GAS-TO-LIQUIDS

Introduction

When natural gas was first discovered, it was generally viewed as a byproduct of oil exploration and production. If gas were associated with crude oil, it was often flared or re-injected. If it were non-associated, it was often considered non-economic or produced to extract its natural gas liquids before flaring or re-injection (e.g., Katy field). Night navigation during the early days of aviation in Texas used gas flares as directional indicators!

At the end of World War II, less than 60% of U.S. gas production was delivered to customers or used as pipeline fuel. Because gas was largely viewed as a byproduct of oil activity at the end of World War II, its price averaged only 5 cents per Mcf. With such a large volume of gas production not reaching customers *and* the volumes that did being almost given away, interest developed in converting gas to liquids (GTL) as a way to extract value from "stranded" natural gas production in the United States. In 1950, the Carthage Hydrocol plant in Brownsville, Texas began operation.

However, development of continental gas markets in the Lower-48 United States after World War II increased gas demand, and lower-48 gas prices began to grow. In addition, large volumes of low-cost oil were discovered outside the United States. By the time operating difficulties with the Hydrocol plant were addressed, GTL economics were unattractive, and the plant was shut down and dismantled in the 1950s.

In the 1990s, interest in GTL technology has revived, largely due to substantial volumes of gas reserves that are "stranded" in remote areas. In the Middle East, the reserves-to-production (RP) ratio is almost 250, and in the former Soviet Union (FSU), it is almost 80. "Stranded" gas also exists in *North Alaska*, where *the marketed gas RP ratio currently exceeds 100*. Furthermore, GTL technology has improved in the last 20 years, and costs have been reduced. Currently, two non-pilot scale GTL plants are operating, and new, commercial-scale plants have been proposed.

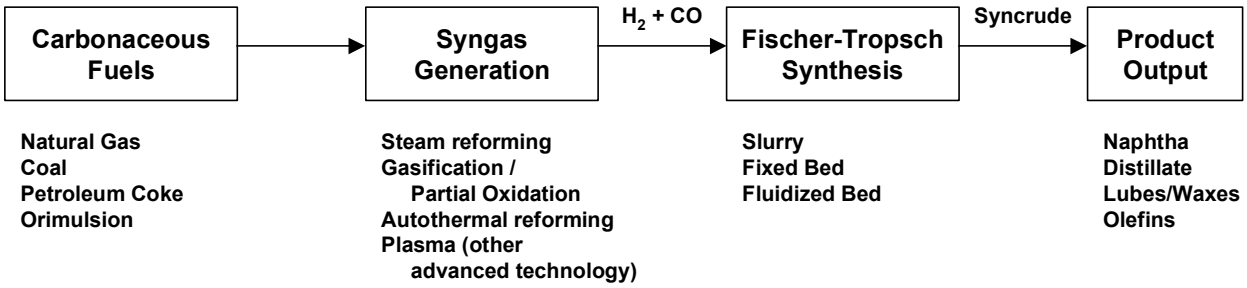
This chapter will review GTL technology and economics and their implications for large-scale commercial development of GTL technology.

GTL Technology

While GTL technology has advanced substantially in the last decade, it is still based on the Fischer-Tropsch (FT) process that was developed during the 1920s to convert syngas made from a carbonaceous fuel, such as coal, into chemicals and liquid hydrocarbons. The FT technology was commercialized in the 1930s, and was used by Germany during World War II to produce 12,000 bpd of liquid hydrocarbon fuels from coal. Commercial-scale FT processes also convert coal-derived syngas to liquids in South Africa (Sasol I-III). Currently, two non-pilot scale GTL plants are operating, Mossgas in South Africa (30,000 bpd) and Shell Bintulu in Malaysia (12,500 bpd).

Figure 6.1 presents a schematic of the basic GTL process. The GTL technology passes through three general processes, syngas production from a carbonaceous fuel, conversion of that syngas into a liquid, and upgrading that liquid to commercial products.

Figure 6.1
Gas-to-Liquids Process Flow



Syngas can be obtained from a variety of carbonaceous fuels, such as natural gas, petroleum coke, or coal. It is principally comprised of hydrogen (H_2), carbon monoxide (CO), and carbon dioxide (CO_2). Only about 10% or less of the syngas is CO_2. The H_2 and CO shares depend on the method used to obtain syngas. If syngas is obtained via steam reforming, H_2 can account for about three fourths of the syngas. If syngas is obtained via partial oxidation, then almost as much CO as H_2 can be made.

Syngas is converted into a waxy syncrude via the basic F-T reaction:

$$CO + 2\ H_2 = C_nH_{2n+2} + H_2O$$

Depending on catalysts, syngas feed assay, and reactor conditions, a variety of syncrudes can be made. Using hydroprocessing or other methods, petroleum products are made from the syncrude. The principal products to date have been naphtha, distillates, olefins, and some lubes and waxes.

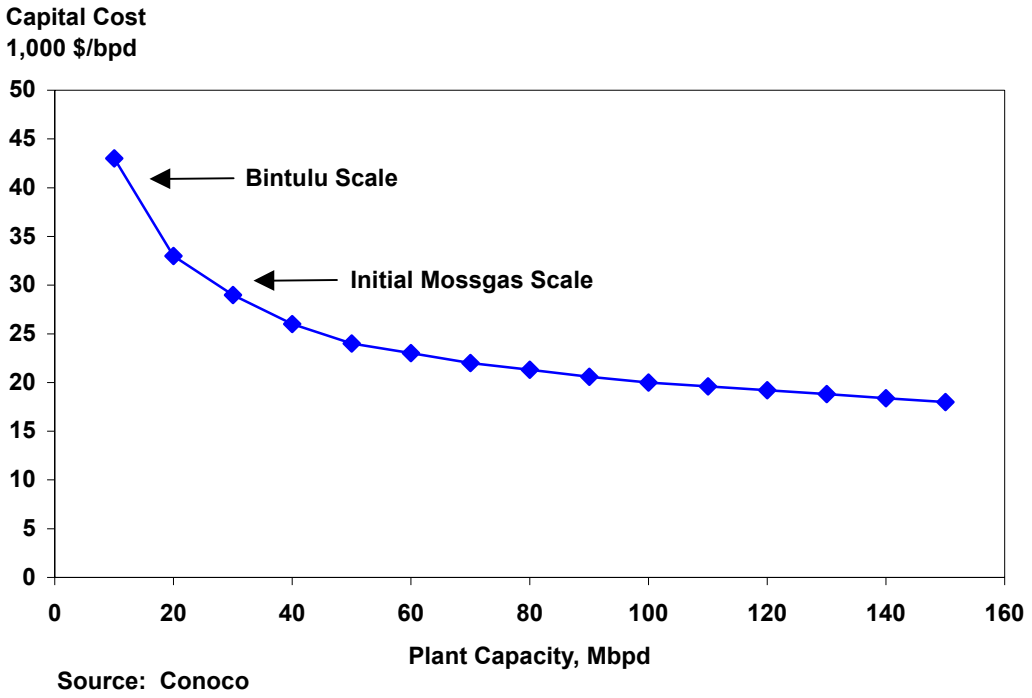
The Sasol plants in South Africa, which currently make petroleum products from coal, have a syncrude yield of about 80% diesel with the remaining 20% paraffinic naphtha. Distillates derived from natural gas have a higher quality (e.g., lower sulfur, higher cetane number) than current "nominal" products from a petroleum refinery, and thus could receive a higher price. As a result, GTL products could command higher prices than "conventional" refinery products. This could allow gas prices to be higher at the inlet of a GTL plant. GTL products, however, cannot really be considered boiler fuel.

GTL Economics

Commercial scale GTL plants are expected to have capacities in the 50-100,000 barrels per day (bpd) range, substantially larger than the two currently operating, non-pilot scale plants in South Africa and Malaysia. Because of economies of scale, capital costs for commercial-scale plants are expected to be on the order of $25-20,000/bpd of capacity, substantially less than capital costs for plants with the capacity of the two currently operating non-pilot scale plants. While a substantial reduction in capital costs is expected, no commercial-scale (>50,000 bpd) plants have been built to date. As a result, the capital intensity for commercial-scale plants should be seen as design targets.

Figure 6.2 presents the trend in capital investment per daily barrel of capacity. Plants at the scale of the Bintulu facility (10,000 bpd) have a capital cost on the order of $40,000/bpd of capacity, for a total cost of $400 million. For a plant with this capital cost intensity, gas would have to be in the 50-75 cents per MMBtu range to be competitive with crude-based products. Industry expectations are that a facility of 100,000 bpd would have a capital cost of $2 billion or $20,000/daily barrel of capacity. The substantial reduction in capital costs for commercial-scale facilities will allow GTL plants to be competitive at gas prices above the often-cited.

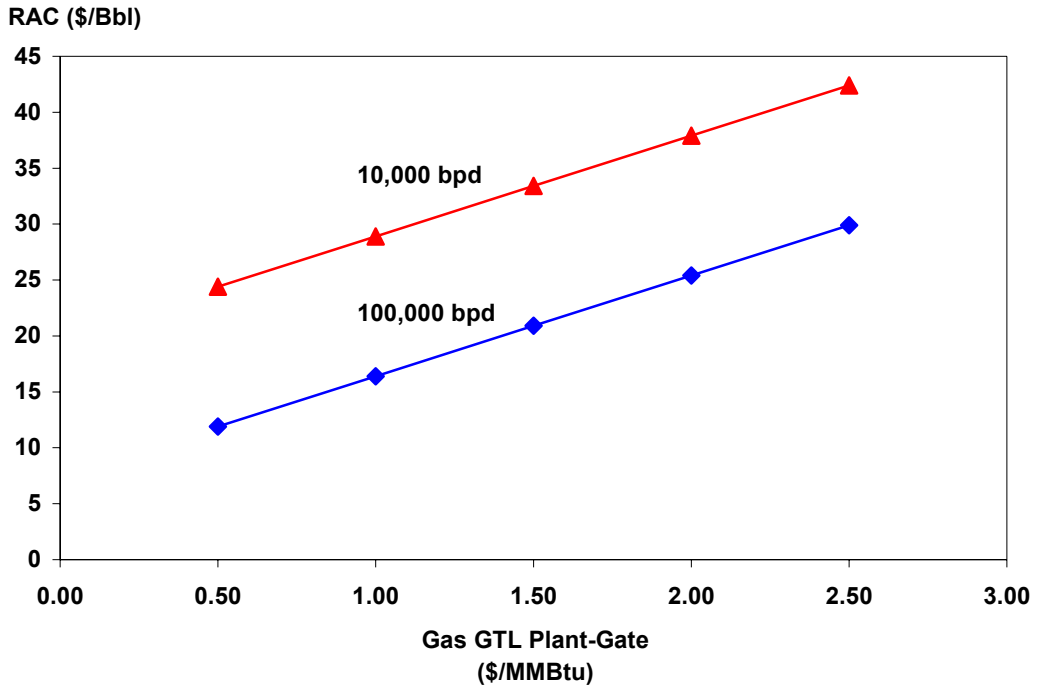
Figure 6.2
Gas-to-Liquids Economies of Scale



Source: Conoco

Figure 6.3 presents the minimum crude oil refinery acquisition price (RAC) at which a GTL plant-gate gas price would be competitive for distillate production. Capital costs are based on a 12% discount rate and a gas conversion efficiency of 9 Mcf per barrel of distillate, about the current efficiency of the Shell Bintulu plant. Distillate prices are taken to be $5.60/Bbl above RAC, the long-term average in the United States since 1980. Because plant-gate gas prices include gathering and some processing expenses, wellhead gas prices would be less than plant-gate gas prices. Gas price versus RAC is calculated for a 10,000 bpd and a 100,000 bpd facility.

Figure 6.3
GTL Gas Prices vs RAC Oil Prices



At current U.S. RAC, gas would have to be delivered to a 10,000 bpd GTL plant-gate at about 50-75 cents per MMBtu. If the capital intensity design targets for a 100,000 bpd GTL facility (Figure 6.2) can be achieved, GTL plant-gate gas prices could approach $2/MMBtu. If long-term RAC prices were to decline to their 1990s average of less than $20/Bbl, then plant-gate gas prices could not exceed $1.50/MMBtu.

The correlations in Figure 6.3 do not include the impact of the higher quality distillate that a GTL plant would produce. The higher price for this higher quality distillate could "add" about 20 cents/MMBtu to the plant-gate gas price. On the other hand, because GTL plants would be built for a "stranded" gas in remote places, GTL capital costs could be higher than shown in Figure 6.2. On the North Slope of Alaska, there might be a "site cost premium" of up to 50%.

Because North Alaska has substantial volumes of "stranded" gas, a North Alaska GTL plant would provide an alternative option to monetize "stranded" North Alaska gas to a gas pipeline to deliver

North Alaska gas to North American gas markets or LNG terminals in South Alaska. Figure 6.4 presents the RAC at which a particular GTL plant-gate gas price would be competitive for distillate production. The correlation is calculated for a 100,000 bpd GTL plant located in South Alaska or North Alaska. The North Alaska facility has a 1.5 "site cost premium" multiplier to its capital costs. The average wellhead oil prices for 2000-01 in North Alaska ($20/Bbl) and South Alaska ($25/Bbl) are indicated for reference.

Figure 6.4
GTL Gas Price vs Oil Price in North Alaska

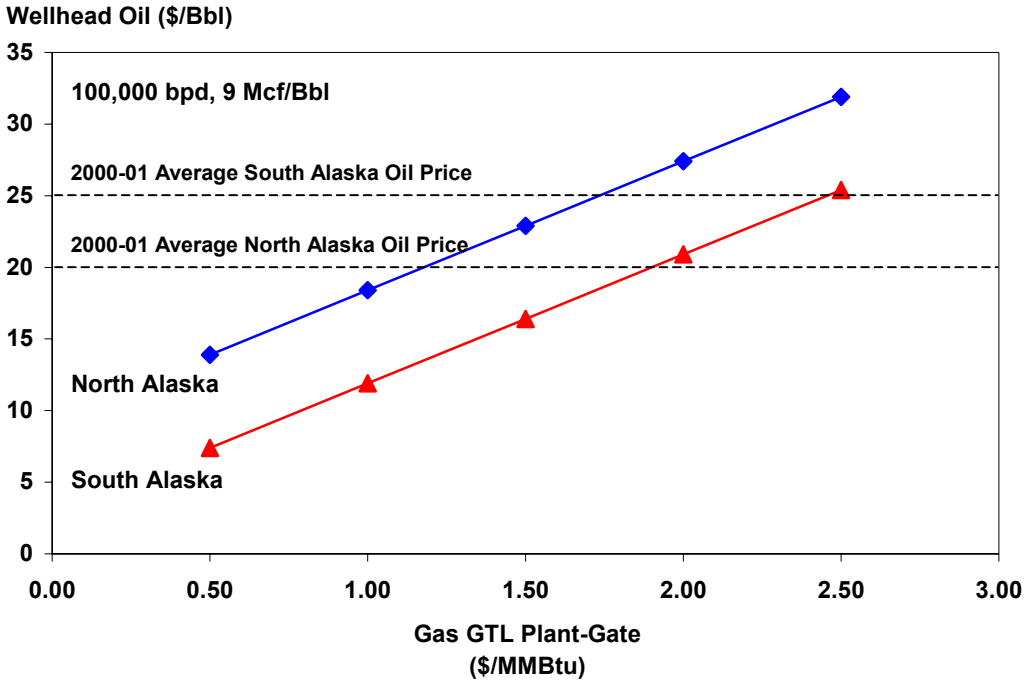


Figure 6.4 shows that, at a wellhead oil price of $20/Bbl in North Alaska, a North Alaska GTL could not pay more than about $1.25/MMBtu for gas and be competitive. However, a GTL plant in South Alaska could pay up to $2.50/MMBtu at the plant-gate for gas if South Alaska oil prices were $25/Bbl. This suggests that delivering gas from the North Slope to a South Alaska GTL might be more attractive than building a GTL plant in North Alaska. On the other hand, products from a GTL facility on the North Slope could utilize the more than 1 million bpd of available liquids capacity in the oil pipeline to Valdez. It is interesting to note that producing 1 million bpd of liquids from gas in North Alaska would utilize about 9 Bcf/d of gas, about the current gas production on the North Slope.

Final Observations

Interest in GTL technology has been growing substantially since the late 1990s. Pilot plants to test out new processes, catalysts, designs, and operating practices are under construction. Sufficient advances may be achieved to reduce capital or operating costs or to improve gas conversion efficiency such that commercial-scale ($20-25,000/bpd of capacity) GTL plant may be as small as 30,000 bpd.

More than 15 commercial-scale facilities (> 30,000 bpd) are under discussion or planning, with many expected to be in operation before 2010. The Sasol facility in South Africa may be converted to using gas as a feedstock instead of coal. The gas demand at this facility would serve as an anchor for a new 840-km gas pipeline under construction to bring gas from Mozambique to South Africa.

Therefore, *GTL technology could reach commercial take-off point by about 2010*. After 2010, GTL capacity could begin to surge. This could have significant implications for U.S. gas supplies and markets.

In some areas, such as the Persian Gulf, LNG may have to compete against GTL for access to "stranded" gas reserves, because GTL may be more attractive than LNG to monetize "stranded" gas. In addition, large-scale development of GTL will probably reduce the demand for world oil, thereby easing upward pressures on oil prices and possibly even capping them for a sustained period of time. Given the large volumes of "stranded" gas reserves in the world, GTL output could grow substantially past 2020 without putting upward pressures on world gas prices.

CHAPTER 7

GAS SUPPLY PROSPECTS

NON TRADITIONAL GAS SUPPLY DELIVERIES TO LOWER-48 GAS MARKETS

Introduction

The non-traditional gas supply sources discussed in this report, Alaska, LNG, Mexico, Hydrates, GTL, have played a minor role in lower-48 gas supply to date. In fact, Mexico has been a net consumer of lower-48 gas supply since the mid-1980s. In 2001, lower-48 gas consumption was 21.0 Tcf (57.6 Bcf/d), but only 108 Bcf (0.5%) of the gas supply to meet this demand came from non-traditional sources. In the future, however, non-traditional sources will play a growing role in lower-48 gas supply. Past 2015, they may provide most or even all of the growth in lower-48 gas supply.

Deliveries to Lower-48 Gas Markets

Supply from non-traditional sources are not necessarily additive. Some LNG delivered to lower-48 gas markets may come from Alaska, and some of the growth in North Alaska gas production may not even be delivered to North American gas markets. Instead, it may go to North Asia or Mexico as LNG or be converted into liquids via GTL technology. Mexico will be a consumer of lower-48 gas supply for about a decade, but then may become a source of lower-48 gas supply.

Figure 7.1 presents the trends in non-traditional gas supply through 2020 for a high supply scenario and a low supply scenario. Trends in total supply are presented along with the volumes expected to be delivered to lower-48 gas markets. The differences reflect gas consumption in North Alaska and North Alaska gas delivered as LNG or converted into GTL.

Figure 7.1
Non-Traditional Gas Supply Scenarios

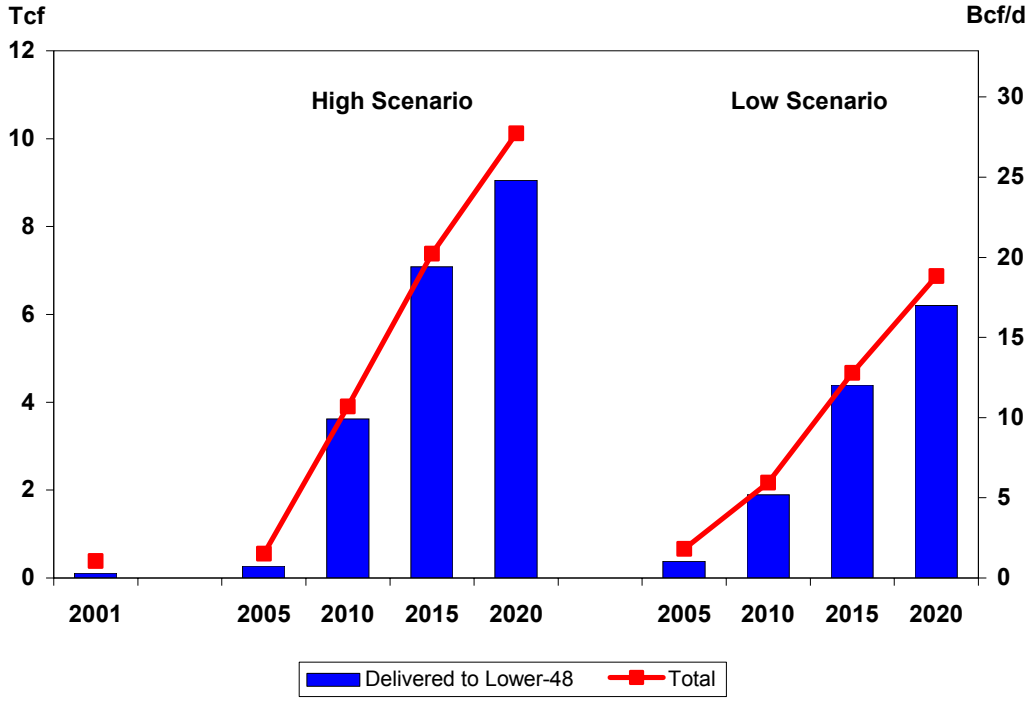


Figure 7.1 shows that non-traditional gas supplies do not become significant until 2010 in either scenario. Although LNG imports grow substantially, half or more of that growth between through 2005 is offset by increased Mexican demand for gas from the lower-48. After 2005, non-traditional contributions to lower-48 gas supply grow substantially, reflecting the surge in LNG and opening of gas pipelines from Alaska. In the **High Scenario**, non-traditional sources deliver 3.6 Tcf (9.9 Bcf/d) of gas to lower-48 gas markets by 2010. By 2020, they provide 9.1 Tcf (24.7 Bcf/d) to lower-48 gas markets, about one fourth or more of expected gas demand in 2020.

In the **Low Scenario**, non-traditional gas deliveries begin to grow rapidly after 2005, reflecting the strong growth in LNG imports. Because gas pipeline deliveries from North Alaska do not begin until after 2010 in this scenario, non-traditional sources only provide 1.9 Tcf (5.2 Bcf/d) by 2010, 87% of total non-traditional supply. By 2020, non-traditional sources deliver 6.2 Tcf (17.0 Bcf/d) to lower-48 gas markets.

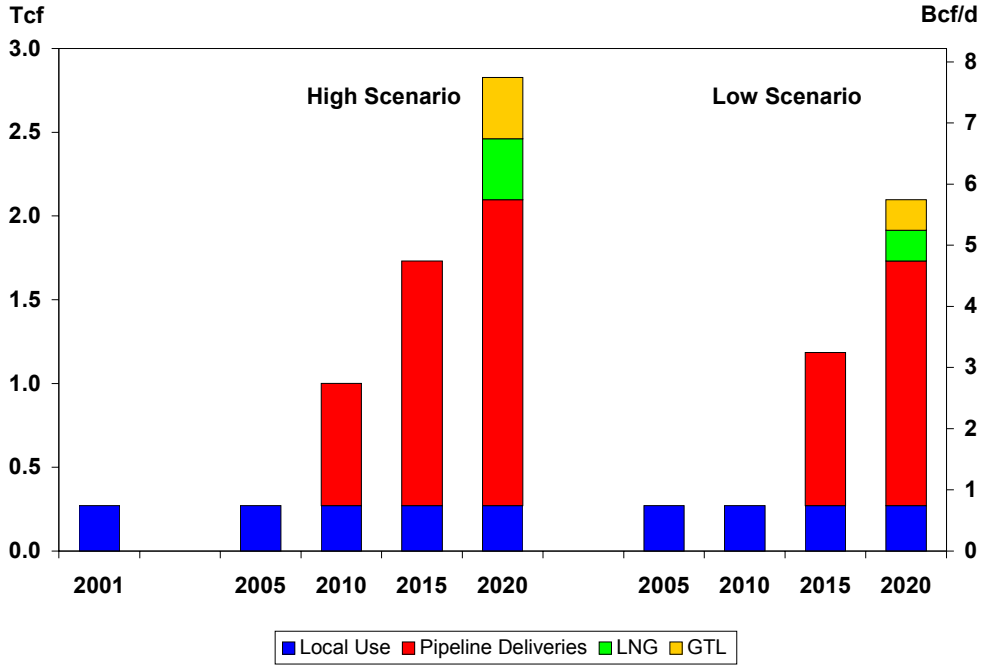
Sources of Deliveries to Lower-48 Gas Markets

Alaska

If *marketed* Alaska gas grows substantially in the next 20 years, that growth will most likely come from North Alaska. However, the extent to which *marketed* North Alaska gas production would be delivered by pipeline to Western Canada and then on to the lower-48 is uncertain. Other options are a gas pipeline to South Alaska where it may be converted to liquids using GTL technology or sent as LNG to North Asia or Mexican gas markets. As a result, although North Alaska gas production grows substantially, a significant share of this gas may not reach lower-48 gas markets.

Figure 7.2 allocates *marketed* North Alaska gas production from the two scenarios in Chapter 2 to pipeline deliveries to Western Canada, GTL, and LNG. In the **High Scenario**, pipeline deliveries to the lower-48 begin in 2010, but LNG exports and GTL conversions do not develop until after 2015. By 2020, North Alaska gas production grows to 7.9 Bcf/d, but only 5 Bcf/d is delivered by pipeline to Western Canada. Of the remaining North Alaska gas production, 0.9 Bcf/d is consumed in North Alaska, and 2 Bcf/d is converted into LNG or liquids for delivery to market.

Figure 7.2
North Alaska Gas Market Scenarios



In the **Low Scenario**, pipeline deliveries to the lower-48 begin after 2010, and LNG exports and GTL conversions do not develop until after 2015. By 2020, North Alaska gas production reaches 5.8 Bcf/d, but pipeline deliveries to Western Canada only reach 4 Bcf/d. Of the remaining North Alaska gas production, 0.8 Bcf/d is consumed in North Alaska, and 1 Bcf/d is converted into LNG or liquids for delivery to market.

The development of GTL and LNG in Alaska for gas deliveries is somewhat conservative -- GTL or LNG demand for North Alaska gas might develop before 2015. If North Slope crude oil production declines substantially, GTL facilities on the North Slope might be attractive because they would increase liquids throughput in the TAPS oil line. This would improve pipeline operational efficiency and reduce pipeline tolls.

However, if South Alaska gas production declines substantially, a demand to move North Alaska gas to the Cook Inlet area (e.g., Anchorage) could develop. To reduce tolls to move North Alaska gas to South Alaska markets, additional volumes might be shipped South for export as LNG to North Asia, California, or Mexico.

LNG

The rapid growth of LNG imports by the United States hit a "bump in the road" after September 11, but LNG imports have begun to recover. The second train at Trinidad has just sent its first cargo to Lake Charles, and the third train should be operating in early 2003. This will more than triple LNG capacity at Trinidad to well past one Bcf/d. In 2001, almost three fourths of Trinidad LNG exports were to the United States, and an additional 15% went to Puerto Rico.

Although LNG imports in 2002 could be less than in 2001, they may leave 2002 at a average daily rate higher than they averaged for 2001 as a whole. While growth through 2010 will be significant, import terminal capacity on the Atlantic and Gulf coasts is likely to have a noticeable surplus due to competition with other importing countries for LNG supply in the Atlantic Basin. After 2010, that competition should lessen, and utilization of import terminal capacity should grow.

U.S. Mexico Gas Trade

Since the late 1990s, *U.S. gas exports to Mexico have grown substantially*, setting new records in 2000 and 2001. U.S. gas exports in 2002 are on a pace to exceed 160 Bcf for the year, another new record. Because the growth in Mexican gas demand is expected to exceed the growth in Mexican gas production, U.S. gas exports to Mexico are expected to continue to grow substantially until LNG imports begin in Mexico outside of Baja California. Once these LNG imports begin, the growth in U.S. gas exports should begin to slow and then decline, depending on the level of LNG imports.

Hydrates

While the hydrate resource dwarfs traditional gas resources in North America, *significant U.S. hydrate production is unlikely to develop until after 2020* because of its current technological status. Most of the accessible (not subject to land restrictions) hydrate resource is located in North Alaska. Given the substantial and growing expectations of ultimate gas resource potential in North Alaska and the technological hurdles facing hydrate development, substantial hydrate production in North Alaska is unlikely to develop until production from traditional resources has peaked, which will probably be well after 2020.

A substantial hydrate resource potential also exists in the Western Gulf, and this would also be accessible. Because traditional gas production in the Gulf of Mexico is near its peak, noticeable progress in hydrate production technology might occur in the Western Gulf of Mexico before anywhere else in North America. More important, hydrate production in the Gulf of Mexico will receive a higher price than production in Alaska.

GTL

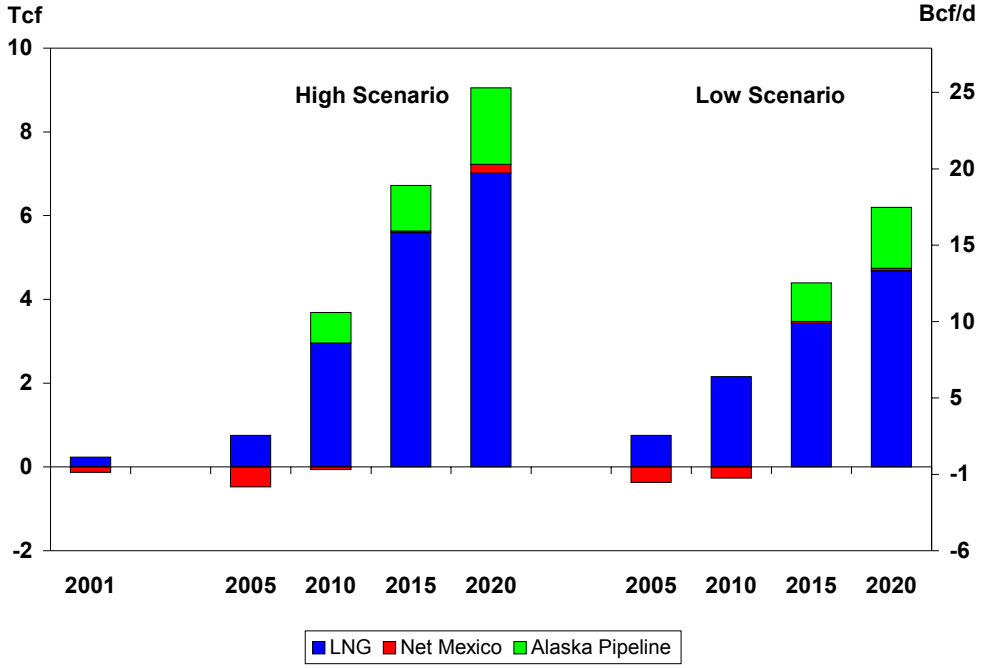
Interest in GTL development has surged substantially in the last decade. Technology advances have allowed *GTL technology to be competitive* at current oil prices but with *gas feedstock prices well above the often-cited 50-75 ¢/MMBtu*. As a result, a significant number of commercial-scale GTL facilities will probably begin operation by 2010. After 2010, GTL expansion could begin to surge, and GTL would become a growing market for "stranded" gas.

"Stranded" gas, however, is also the principal gas source for the expected surge in global LNG supply during the next 20 years. As a result, GTL may compete with LNG as a market for "stranded" gas reserves.

Deliveries to Lower-48 Gas Markets

Figure 7.3 presents the outlook for gas deliveries to lower-48 gas markets from non-traditional gas sources for a high and a low scenario. Mexico is presented on a net basis, depending on whether gas flows from the lower-48 to Mexico or visa versa. Alaska deliveries are by pipeline only. Alaska LNG that is delivered to lower-48 gas markets is included in the LNG volumes.

Figure 7.3
Non-Traditional Gas Supply to Lower-48



Gas supply from non-traditional sources grows modestly through 2005, reflecting the offsetting effect of a growing Mexican demand for gas supplies from the lower-48. In the **High Scenario**, the growth in Mexican gas demand offsets more than half of the growth in LNG imports. As a result, the outlook for U.S.-Mexico gas trade will be a significant factor in near-term non-traditional gas supply growth.

After 2010, the role of non-traditional gas supply begins to surge. By 2020, non-traditional gas deliveries in the **High Scenario** to the lower-48 reach 9.1 Tcf (24.7 Bcf/d), with more than three fourths coming from LNG. In the **Low Scenario**, non-traditional gas deliveries reach 6.2 Tcf (17.0 Bcf/d) by 2020, of which three fourths comes from LNG.

Mexico's role changes from one of a consumer of lower-48 gas supply to a source of lower-48 gas supply. In both scenarios, the Mexican demand grows substantially, but then begins to decline. By 2015, there is a net gas flow from Mexico to the lower-48, although it is quite modest.

Gas pipeline deliveries from North Alaska grow substantially. In the **High Scenario**, they reach 5 Bcf/d by 2020. In the **Low Scenario**, they reach 4 Bcf/d by 2020.

Overall, non-traditional sources will not play a significant role in lower-48 gas supplies in the near term. In the long term, however, gas from non-traditional sources are likely to grow very rapidly. After 2015, they might provide most or even all of the growth in lower-48 gas supply.

Impact on Lower-48 Gas Prices

Non-traditional sources will play a growing role in providing incremental gas supplies to lower-48 gas markets, becoming the marginal source of gas supply and thus the price-setters in lower-48 gas markets. While the increase in gas prices since the mid-1990s has make LNG and possibly North Alaska gas economically viable in lower-48 gas markets, *an increased role of non-traditional gas sources in lower-48 gas supply will probably reduce upward pressures on future gas prices*.

The economics of non-traditional gas sources are driven more by threshold affects than depletion effects. Because of the large volumes of "stranded" gas reserves and their large remaining potential resources, prices necessary to bring about large-scale development of these sources are unlikely to show much effects of resource depletion through 2020. In fact, continued reduction in the costs of LNG might even lead to some short- to medium term downward pressures on lower-48 gas prices, if and when LNG becomes the marginal source of lower-48 gas supply.

However, market factors may put upward pressures on prices for "stranded gas" because of competition between GTL plants and gas markets for access to "stranded gas." This competition could be significant, particularly for more remote "stranded" gas sources. The extent of this competition is uncertain at this point, and needs further study.

While significant commercial gas production from hydrates is not likely until about 2020 or later, the extraordinarily large potential volumes of gas in hydrates indicates that, if gas from hydrates becomes economic, *real* gas prices will be capped for a substantial period of time. In fact, depending on the technical success in improving the economic attractiveness of gas production from hydrates, large-scale gas production from hydrates might even lead to some decline in gas prices.