Meeting the Gas Supply Challenge of the Next 20 Years

Lower-48 and Canada

Prepared for

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NORTH AMERICAN GAS SUPPLY

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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. The most recent National Petroleum Council (NPC) gas study and Energy Information Administration (EIA) long-term energy outlook expect U.S. gas consumption to exceed 30 Tcf after 2010. 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.

Currently, 99% of U.S. gas supply comes from the lower-48 United States or Canada. While this share is expected to shrink as LNG imports grow and deliveries from Alaska possibly begin in the next seven or more years, lower-48 and Canadian gas production will continue to play the major role in U.S. gas supply. The NPC and EIA expect that new discoveries of about 600 Tcf in the lower-48 and 200 Tcf in Canada would be needed to supply a U.S. gas demand on a path to a 30 Tcf or larger market over the next 15 years.

The natural gas industry is presented with significant opportunities, but these opportunities are accompanied by significant challenges. The critical issue is whether lower-48 and Canadian gas production can grow over the next 20 years without sustained upward pressures on gas prices that would reduce the attractiveness of gas as a fuel of choice for new energy uses.

Resource & Technology: While the gas resource base is finite and thus depleted by industry activity, expectations of lower-48 and Canadian gas resource potentials have expanded with industry activity throughout the twentieth century.

Lower-48/Canada Activity: While measures of resource potential can expand, recovery of that additional resource may come at an increasing cost.

Gas Supply Prospects: While the resource potential may continue to expand, that expansion will not necessarily occur along the regional lines of current production.

Critical Issues and Uncertainties: Many potential areas of new gas resource potential may require technology advances to be attractive to develop, and some areas may face development restrictions on the basis of environmental concerns.

Resource Dynamics

The problem with "ultimate" resource estimates is that they are not "ultimate." While the North American gas resource base has been depleted by industry activity, that same activity has expanded perceptions of the remaining potential. Over the last 20 years, estimates of lower-48 and Canadian gas resource potentials have generally grown faster than the resource was depleted. As a result, lower-48 and Canadian gas resource potentials are larger today than they were 20 years ago.

- Improved success rates since the 1980s have allowed drilling activity to move into relatively unexplored, deeper sediments (below 10,000 feet) at much lower risks and costs. In the late 1980s, lower-48 success rates for wells deeper than 10,000 feet were in the 50-60% range. Today, they exceed 80%.

- *Technology advances* have allowed large-scale development of *unconventional gas sources* (e.g. coalbed methane, tight sands, shales) since the late 1980s. Continued improvements have allowed unconventional activity to expand into new areas, such as coalbed methane in Powder River Basin and shales in the Fort Worth Basin. Western Canada may also have a significant coalbed methane potential that might even exceed current estimates of the remaining conventional resource potential.

- Although the lower-48 and Western Canada have been heavily explored, large areas, such as the Offshore Atlantic (lower-48 and Canada), Mackenzie Delta-Beaufort Sea, and Eastern Gulf of Mexico, can be considered *frontier*. Current resource estimates for most *frontier* areas appear very conservative, suggesting that they will generally be the least productive areas in North America. In fact, if the sediments in these areas were to prove as productive as the lower-48 Williston Basin sediments, their resource potentials could increase substantially.

- Based on trends in North American gas resource estimates over the last 20 years and the expectations of continued advances in technology and industry practice, the “ultimate” resource recovery in currently producing lower-48 areas might increase on the order of 300-600 Tcf over the next 20 years. Over this same period, the Western Canadian resource potential may increase 100-300 Tcf, --- the major Western Canada uncertainty is the extent to which coalbed methane might prove productive.

- Therefore, gas resource potentials could expand at or ahead of the resource depletion necessary to achieve a 30 Tcf gas market. If so, a 30 Tcf gas market would probably not put significant, *sustained* upward pressures on *gas prices*. However, it is likely that continued development of the natural gas resource base will require some real increase in wellhead prices over time. Reports such as the aforementioned *Fueling the Future* indicate price growth from a current level of about $2.65 per mmbtu to $3.60 (1999$) by 2020.

Lower-48 Activity

Results in the lower-48 generally support expectations of a continued expansion in the lower-48 resource potential. Non-associated gas reserves have not declined since 1976 and have begun to grow substantially in the late 1990s. Reported reserve additions for non-coalbed methane gas wells in the lower-48 have grown modestly since the mid-1990s, and now average over 1.8 Bcf/well, more than double the yield of the early 1980s. While coalbed methane yields have declined, this decline reflects a shift of activity from the high-yield San Juan Basin to the low-yield Powder River Basin.

- If yields remain near their current levels, the 19,000 or so new gas wells completed in 2001 could add as much as 25-30 Tcf of new gas reserves. This could bring non-associated gas reserves to their highest level since the early 1970s.

- From a reserves and yields basis, prospects to maintain or increase lower-48 gas production appear good. However, accelerated declines in gas well production since the late 1990s have increased the demand for new gas wells above simple reserves replacement. This incremental demand for gas wells placed upward pressures on gas prices in the late 1990s, and should continue to do so until decline rates stabilize. Once decline rates stabilize, demand for new gas drilling should decline to simple reserves replacement, which would be much less than 19,000 wells. For non-associated gas production to grow, reserve additions will need to average 10-20% above production.

- Yields have been quite stable to growing in most parts of the onshore lower-48. Based on yields, Rocky Mountains basins, South Texas, North Texas/Louisiana, and the smaller producing areas (in aggregate) scattered across the lower-48 from California to the Appalachian Basin have the best prospects for increased production. Yields in the rest of the onshore lower-48 suggest that their production will probably show little or no growth, and may more likely decline at some point in the next 20 years.

- The recent sharp decline in yields on the Gulf of Mexico suggest that prospects for near-term stabilization of Shelf production are poor. Stabilization of Shelf production or some modest recovery would probably take time *and* depend on large volumes of hydrocarbons being recoverable from the deeper sediments of the Shelf *and* technology advances to reduce the costs and risks associated with bringing the deeper Shelf resource to market. As a result, a significant share of the expected growth in Deepwater Gulf of Mexico gas production may be needed to offset declines in Shelf production.

Canadian Activity

Following market deregulation Western Canada gas production more than doubled between 1986 and 2000. In 2000, a quarter (24%) of North American gas production came from Canada. If U.S. gas demand is to grow to 30 Tcf and beyond, Canadian gas production will play a critical role in meeting that demand.

- *Growth in Western Canadian gas production*, which accounts for almost all (99%) of Canadian gas production, *has slowed since 1996*. The limited growth in Western Canadian gas production since 1996 is consistent with the RP ratio (reserves inventory) in Western Canada falling to 9.1. While production could be held at current levels if reserves can be maintained, *sustained, significant growth* in Western Canada gas production would probably require *proved reserves to exceed 60 Tcf.*

- Deliveries of gas production from the offshore Atlantic began in 2000 from *Sable Island*. By December 2001, Sable Island production was almost 590 MMcf/d. Production from the Panuke discovery could increase Offshore Nova Scotia production to one Bcf/d by 2005.

- Gas production in Offshore Newfoundland is almost half the level of Sable Island production, but almost all is re-injected into the Hibernia oil field to improve recovery. Plans to develop additional oil production in Offshore Newfoundland might bring gas production to about one Bcf/d, which might be sufficient to develop interest in building a gas transportation system to bring Offshore Newfoundland gas production to market.

- Significant discoveries have also been made in the *Mackenzie Delta-Beaufort Sea* area. Current industry plans envision deliveries to North American gas markets beginning before 2010. While onshore discoveries provide an anchor to build a pipeline from the Mackenzie Delta to the North American gas transmission grid, new discoveries would be needed to maintain a 25-year delivery of one Bcf/d.

- Canadian gas production can grow in the future, but that growth is likely to rely mostly on production outside Western Canada *or* a large development of *coalbed methane* production in Western Canada. Based on current reserves, long-term growth in Western Canada conventional gas production is uncertain, and unlikely to exceed 100 Bcf/yr.

- Activity outside of Western Canada should provide substantial, additional gas production. This growth, however, would depend on large expansions of the "ultimate" resource base and development of "green field" pipeline projects to connect these mostly "remote" areas to North American gas markets.

Gas Supply Prospects

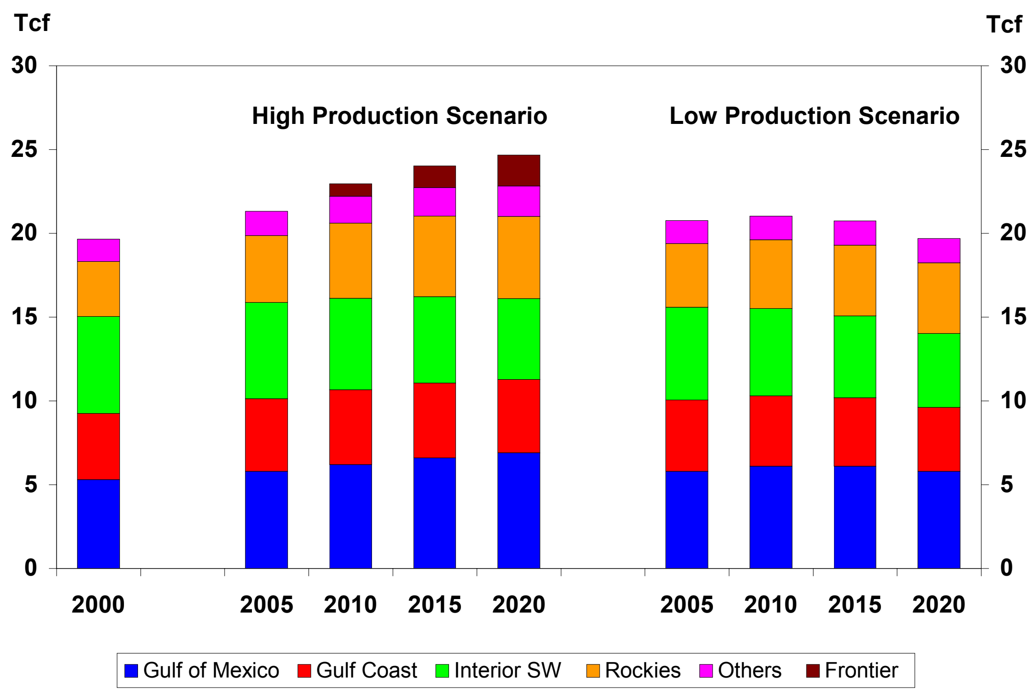
Two production scenarios are developed in this report. The **High Production Scenario** expects that "ultimate" gas resource estimates expand ahead of resource depletion, as they generally have for the last 20 years. A **Low Production Scenario** expects that expansions of the "ultimate" resource estimates will slow in the next 20 years. *The production scenarios should not be seen as forecasts, but as indicators of the range over which lower-48 and Canadian production might be expected to develop.*

RP ratios for onshore areas probably should be *about 10 before prospects for sustained growth* (more than one year) *in production are solid*. If gas production is to show *sustained* grow, reserve additions in Western Canada and the Gulf of Mexico must exceed simple reserves replacement to increase their RP ratios. "Onshore" lower-48, gas reserves could support some growth, *provided* future reserve additions can replace the higher production.

Putting both Lower-48 and Canada production potential together within the context of the High and Low Production Scenarios, creates a range of gas supply potential between 24.2–31.0 Tcf annually by 2020 for consumption in the Lower-48. Lower-48 production ranges from 19.7 to 24.0 Tcf. Canada may be capable of producing 8.5-11.0 Tcf annually but is not expected to consume more than 4.0 Tcf, so 4.5-7.0 Tcf may be available for export to the Lower-48.

Figure ES 1 presents the trends in lower-48 gas production for the two scenarios based on prospects for the individual regions.

Figure E S1
Lower-48 Gas Production Scenarios



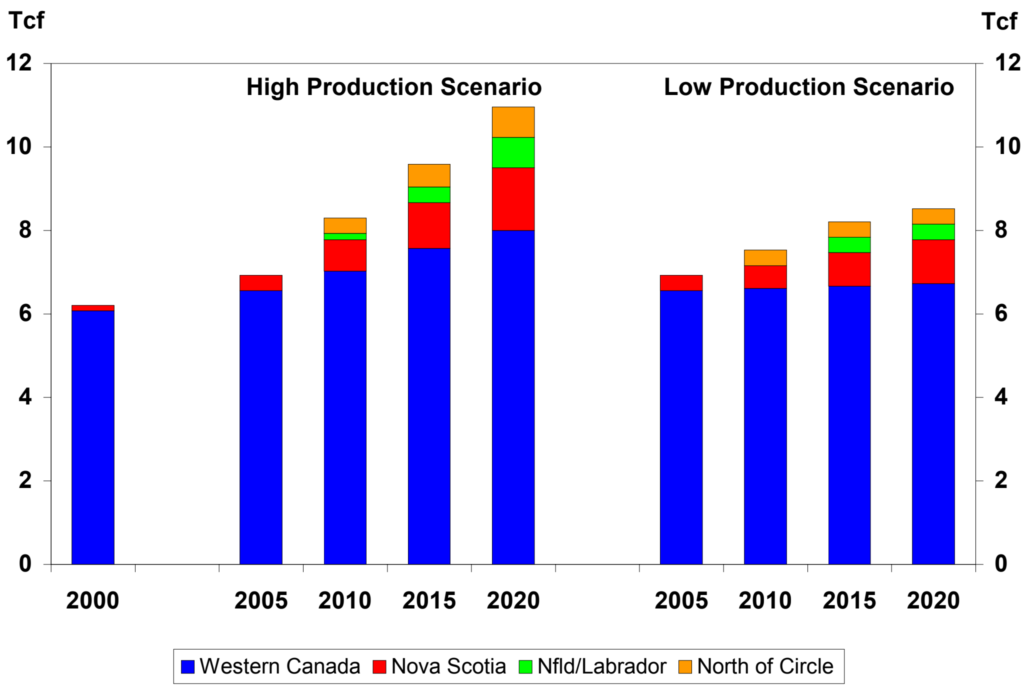
- Lower-48 gas production exceeds its previous peak of 22.5 Tcf by 2010 in the **High Production Scenario**. However, without production from areas subject to moratorium, growth in lower-48 gas production would be largely over by 2015.

- In the **Low Production Scenario**, there is some growth in the near term, but production falls off after 2010. By 2020, production has fallen back to its 2000 level. Frontier regions (i.e. East Gulf of Mexico and Offshore Atlantic) do not begin production in the **Low Production Scenario**.

- In both scenarios, the major growth areas are the Gulf of Mexico and the Rocky Mountains.

Figure ES 2 presents the trends in Canadian gas production for the two scenarios allocated to the individual regions.

Figure ES 2
Canada Gas Production Scenarios



- *Total Canadian gas production grows substantially in both scenarios.* In the **High Production Scenario**, production almost doubles, growing from 6.2 Tcf (17.0 Bcf/d) to 11.0 Tcf (30.1 Bcf/d) in 2020. Growth occurs in all areas, but most noticeably outside of Western Canada. Most of the growth in Western Canada reflects the development of coalbed methane production. By 2020, more than one fourth of Canadian gas production could come from outside Western Canada.

- In the **Low Production Scenario**, Canadian gas production only grows through 2015. In this scenario, little growth occurs in Western Canada gas production, reflecting limited development of coalbed methane. *Non-Western Canada gas production grows substantially*, accounting for almost one fourth of Canadian gas production by 2020.

Issues and Uncertainties

Prospects for increased North American gas production to supply a growing gas demand appear strong. While this growth could extend through 2020, significant challenges must be addressed to achieve this growth. Principal among them are:

- *North American gas reserves inventories must be rebuilt to support sustained growth in gas production.* Current RP ratios in Western Canada and in the Gulf of Mexico cannot support long-term, sustained growth in gas production. During the period of rebuilding these inventories, short-term upward pressures on gas prices are likely to develop, pushing gas prices above their long-term trends. These upward pressures will continue until inventories are rebuilt to a level that would support sustained growth in gas production. *Once inventories are rebuilt, gas prices would probably tail off to their long-term levels*.

- *The pace of advances in technology and industry practice and expanded industry perceptions of the "ultimate" resource base over the last decade must be maintained.* The "ultimate" resource expectations must expand faster than resource depletion to avoid or mitigate upward pressures on gas reserve additions, and advances in technology and industry practice will be critical to this expansion.

- *Impacts of land restrictions on the growth in North American gas production must be weighed against the extent to which public policy may wish to encourage expanded use of gas.* Land restrictions will probably have limited impacts on lower-48 production prospects through about 2010. However, land restrictions may result in lower-48 gas production peaking within 10-12 years and possibly beginning to erode towards the end of the next decade.

CHAPTER I

PERSPECTIVE

PERSPECTIVE

Introduction

The outlook for the North American gas industry has experienced significant volatility in the last 40 years. This volatility reflects the changing expectations for North American gas production. In the 1960s, North American gas production was growing rapidly, and this growth was expected to continue. The natural gas industry had a bright future.

In the 1970s, resource "depletion" *again* became quite prominent in strategic discussions. Because of the limited remaining U.S. gas potential, U.S. gas production was expected to begin a long-term decline. U.S. public policy was directed at preserving a shrinking and increasingly expensive gas supply for high priority residential and commercial users. Large industrial users and electricity generating plants were to be compelled to switch to alternative fuels. In Canada, public policy was directed at preserving a limited gas supply for Canadian customers by phasing out gas exports to the United States. By the mid-1980s, U.S. gas demand had fallen to its lowest level since the late 1960s, and Canadian exports were down about one-third from their peak.

Since the mid-1980s, the outlook has changed. By the mid-1990s, U.S. gas sales were at a new record level, and gas sales to generate electricity were a major player in this growth. Canadian gas exports were more than triple their previous peak. By the late 1990s, more than half of Canadian gas production was exported to the United States.

With recovery in North American gas consumption, optimism has again returned to the North American gas industry. A U.S. gas market of 30 Tcf or more has become the strategic goal of industry and government. The major contributors to this growth would be the previously maligned large industrial and electricity generation customers.

In 2000, U.S. gas consumption set a new record, exceeding its previous peak of 22.5 Tcf in 1972-73. With gas-fired plants expected to provide the major share of future growth in electricity generation, growth to a 30 Tcf market and beyond appeared likely. The critical uncertainty will be the sources of the gas supply to meet this growing gas demand during the next 20 years.

Gas Supply Expectations

Currently, 97% of North American gas supply comes from the Lower-48 United States or Canada. Although LNG and Alaska only provided about 3% of North American gas supply in 2000, their contributions are expected to grow over the next 20 years. However, lower-48 and Canadian gas production will continue to play the major role in North American gas supply. If they cannot, then a 30 Tcf gas market may not be achievable in the next 20 years.

The most recent National Petroleum Council study (published in 1999) and Energy Information Administration (EIA) long-term energy outlook (AEO 2002) expect U.S. gas consumption to exceed 30 Tcf after 2010. The American Gas Foundation's *Fueling the Future* (2001 Update) anticipates a gas consumption market that could grow to 33 Tcf annually. While these long-term views expect growth in LNG imports, the outlooks expect that the lower-48 resource base would provide an additional 600 Tcf of new gas discoveries and the Canadian resource base about 200 Tcf. This resource dynamic through 2020 could bring lower-48 and Canadian gas production to more than 30 Tcf by 2020 from its current level of 25 Tcf.

These resource depletions are less than current estimates of the remaining resource potential of 900-1,500 Tcf for the lower-48 and 450 Tcf for Canada (excluding "Arctic Islands"). However, unless the lower-48 resource base could expand over the next 20 years, a cumulative 600 Tcf depletion could probably not occur without sustained upward pressures on gas prices throughout much of the period. Without expansion of the Canadian gas resource base, a cumulative 200 Tcf depletion without sustained upward pressures on gas prices would be uncertain.

The gas industry is presented with significant opportunities, but these opportunities are accompanied by significant challenges. The critical issue is whether current estimates of remaining gas potentials in the lower-48 and Canada can expand sufficiently to provide the incremental gas supply that a 30 Tcf gas market in the United States would demand without sustained upward pressures on gas prices. This report will address this issue in the following chapters:

Resource & Technology: While the gas resource base is finite and thus depleted by industry activity, expectations of lower-48 and Canadian gas resource potentials have expanded with industry activity throughout the twentieth century, predictions of declines in the remaining resource potential notwithstanding. *Can expectations of the lower-48 and Canadian remaining gas resource potentials continue to expand?*

Lower-48 Activity: While expectations of resource potential can expand, that expansion may come at an increasing cost. *Do industry results in the lower-48 support continued expansion in the resource potential with limited, sustained upward pressures on gas prices?*

Canadian Activity: While expectations of resource potential can expand, that expansion may come at an increasing cost. *Do industry results in Canada support continued expansion in the resource potential with limited, sustained upward pressures on gas prices?*

Gas Supply Prospects: While the resource potential may continue to expand, that expansion will not necessarily occur along the regional lines of current production. *Where would lower-48 and Western Canada gas production be more likely to grow in the next 20 years?*

Critical Issues and Uncertainties: Many potential areas of new gas resource potential may require technology advances to be attractive to develop, and some areas may face development restrictions. *What are their implications for the production prospects that the gas resource potential might make available in the next 20 years?*

The production prospects developed in this report should not be seen as a forecast of what will occur, but rather what might occur if a 30 Tcf market were achieved.

CHAPTER 2

RESOURCE & TECHNOLOGY

RESOURCE & TECHNOLOGY

Introduction

In the 1960s, M. King Hubbert concluded that most of the U.S. oil and gas resource had been discovered. Based on his analysis, Hubbert predicted that U.S. oil and gas production would peak in the early 1970s and then fall off steeply. When U.S. oil and gas production peaked in the early 1970s, his work received extraordinary credibility.

However, neither U.S. oil nor U.S. gas production has declined precipitously since their early 1970s peaks. Gas production since Hubbert's paper has exceeded the remaining resource that he predicted, and current estimates of the remaining lower-48 gas resource potential are substantially higher than they were 20 years ago. In fact, marketed (wet) lower-48 gas production in 2001 may have exceeded 20 Tcf for the first time since 1974. Nevertheless, concerns about the depletion of natural gas resources continue to play a significant role in strategic assessments of the U.S. energy system.

Concerns about resource depletion are not new. In 1920, the chief geologist of the U.S. Geological Survey (USGS) predicted an *imminent peaking and near-term decline* in U.S. oil production. While oil production declined in some areas that were producing in the 1920s, production grew in most areas of the United States. Production grew in other areas because the resource proved to be much larger, and non-producing areas, such as the Permian Basin, became major producing areas. As a result, U.S. oil production continued to grow for 50 years after this prediction was made.

The problem with "ultimate" resource estimates is that they are not "ultimate." Just as discoveries grow with industry activity, that same activity expands perceptions of the "ultimate" resource as well. Thus, resource estimates should be seen as dynamic, not fixed. As industry "depletes" the resource base, that activity can expand industry perceptions of the remaining potential. Unless the dynamics of resource estimates are taken into account, assessments of gas prospects based on a static "ultimate" resource will significantly understate what could *and* will be discovered and produced.

The critical question is not an "ultimate" resource estimate but whether current resource expectations can expand to keep pace with "depletion" of the resource base. *Only when expanding resource expectations cannot keep pace with "depletion" of the resource base can the resource base be said to be truly depleting.*

This chapter will review resource estimates for the lower-48 United States and Canada over the last 20 years. Of critical importance is the extent to which new non-producing resources or sediments remain to be developed. Because economics of resource development affect perceptions of remaining resource potential, *technology advances* that reduce costs and risks or improve recovery of the resource-in-place play a critical role in expanding perceptions of the resource potential. Accordingly, this chapter will review:

- lower-48 gas resource dynamics
- Western Canada gas resource dynamics
- technology trends
- "frontier" regions.

Based on these reviews, the likelihood of resource estimates being able to keep pace with resource depletion will be assessed.

Lower-48 Resource Dynamics

Recent "ultimate" (discoveries plus potential) lower-48 gas resource estimates are much larger than they were 20 - 25 years ago, when they were in the neighborhood of 1,400-1,500 Tcf. Current estimates are in the neighborhood of 2,000 Tcf or more. Figure 2.1 compares the growth in "ultimate" resource estimates against resource depletion for resource estimates developed by the Potential Gas Committee (PGC) between 1980 and 2000, the USGS and Minerals Management Service (MMS) between 1979 and 1993/1994, and the National Petroleum Council (NPC) between 1990 and 1997.

Figure 2.1
Lower-48 "Ultimate" Gas Resource Dynamics
Resource Depletion vs. Resource Growth

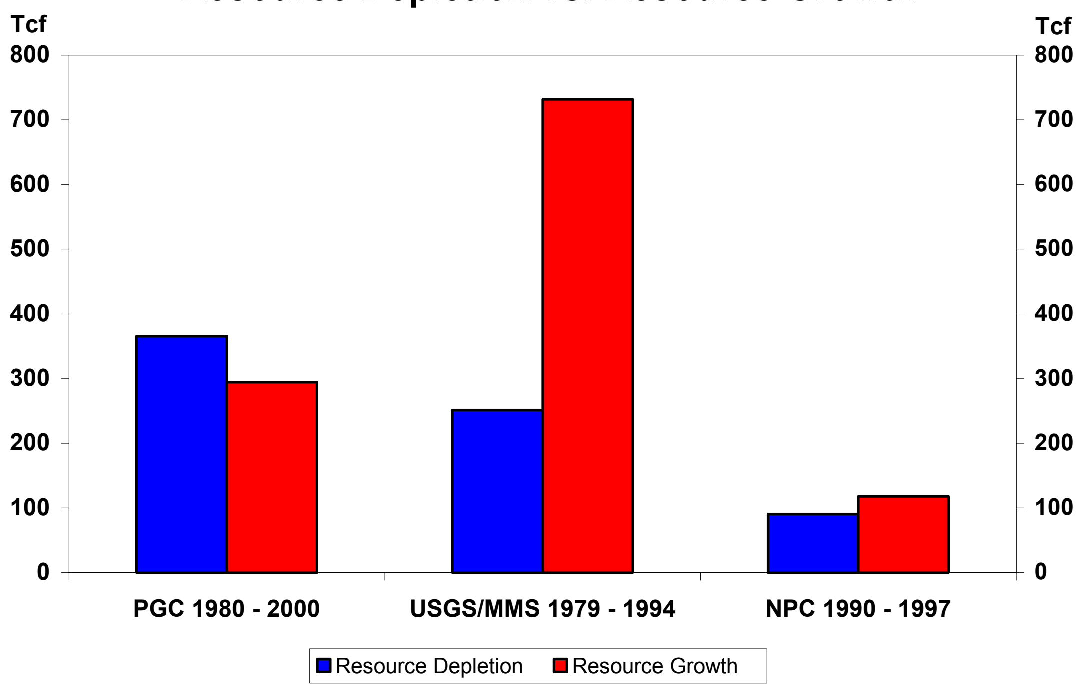
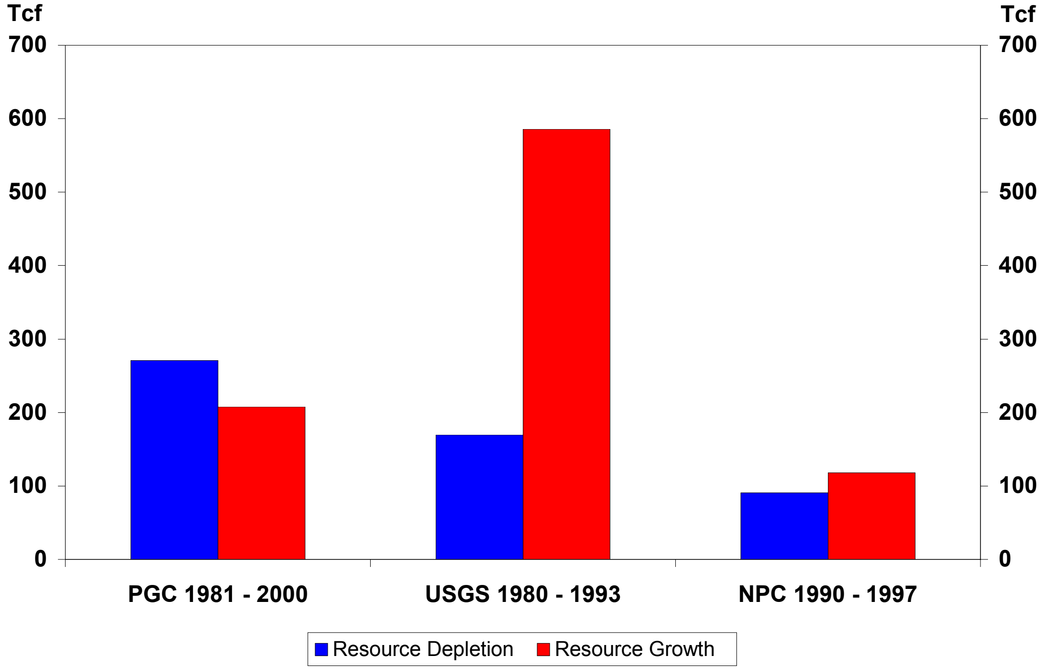


Figure 2.1 shows these "ultimate" resources estimates have grown substantially. The USGS/MMS and NPC estimates of the "ultimate" lower-48 gas resource have expanded more than the resource was "depleted." The USGS/MMS estimate in 1993/1994 replaced almost three times the "depletion" of the gas resource base that occurred between 1979 and 1994. The NPC estimate in 1997 increased its "ultimate" resource 30% more than it was "depleted" between 1990 and 1997. While the PGC shows the least relative growth in its estimate of the "ultimate" resource, its estimate of the "ultimate" resource potential "replaced" 80% of the depletion that occurred between 1980 and 2000.

Onshore Lower-48

The onshore lower-48 was considered largely explored even 20 years ago. As a result, the onshore lower-48 resource potential should have declined significantly during the last 20 years. However, by 2000, the onshore lower-48 resource *potential* was little changed or up to almost double the previous estimates. Figure 2.2 presents onshore lower-48 resource dynamics for the three estimates.

Figure 2.2
Onshore "Ultimate" Lower-48 Gas Resource Dynamics
Resource Depletion vs. Resource Growth



The expansion of the PGC estimate for the onshore lower-48 between 1980 and 2000 "replaced" 77% of the "depletion" between 1980 and 2000. As a result, the *PGC estimate* of the undiscovered *onshore potential declined 10%* between 1980 and 2000. Almost half of the PGC resource growth between 1980 and 2000 was due to the inclusion of the *coalbed methane* resource in its assessment.

The USGS expanded its estimate of the "ultimate" onshore lower-48 gas resource more than three times the "depletion" of the resource between 1979 and 1993. As a result, its estimate of the undiscovered onshore lower-48 resource potential grew 80% between 1979 and 1993. While more than 60% of the increase reflected inclusion of unconventional (i.e. shales, tight sands, coalbed methane) resource in the 1993 USGS estimate, even the conventional resource grew 30% more than it was "depleted" between 1979 and 1993.

Based on industry results between 1990 and 1997, the NPC estimate of the "ultimate" onshore lower-48 gas resource grew 13% more than the resource was "depleted," even though its base 1990 estimate included a large unconventional resource Almost all the growth was conventional gas.

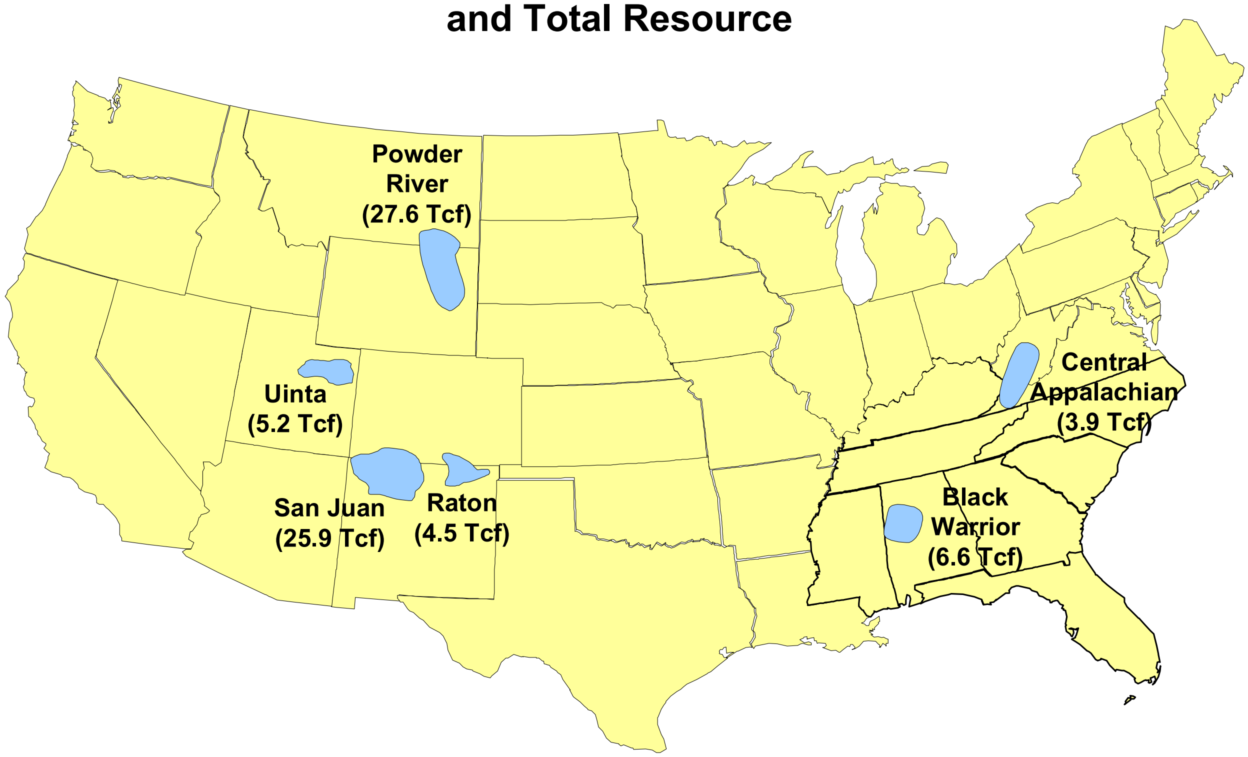
Prospects for continued growth in onshore gas resources to offset "depletion" of the resource base depend on growth in both conventional and unconventional prospects. Despite extensive exploration, *most sediments below 15,000*, and sometimes even 10,000 feet (e.g. South Texas) *have had limited exploration*. Because lower-48 sediment yields (MBOE/mi^3) tend to grow with depth, significant volumes of gas may be discovered in deeper sediments.

Unconventional gas sources also expand lower-48 resource expectations. Shale production spread from the Appalachian Basin to the Michigan Basin (Antrim shales) and recently became noticeable in Northeast Texas (Fort Worth shales). Current production exceeds 1 Bcf/d, and should continue to grow. Neither Antrim nor Fort Worth shales were considered credible exploration targets 20 years. If technology to improve recovery of gas-in-place and field production facilities can be developed, some studies suggest that Appalachian shale production could double or more in the next 15 years.

Coalbed methane is the most visible unconventional source approaching 4 Bcf/d in 2000. Almost all of this production came from the San Juan, Powder River, Black Warrior, Uinta, Central Appalachian, and Raton basins. Production ranged from 36 Bcf (100 MMcf/d) in the Raton Basin to 960 Bcf (2.6 Bcf/d) in the San Juan Basin in 2000. Less than 5 Bcf came from other basins.

Figure 2.3 shows the principal coalbed methane producing basins and estimates of their "ultimate" coalbed methane recovery (including discoveries to date) based on the 2000 Potential Gas Committee (PGC) report. The recoverable resource in these six basins is 74 Tcf (as of December 31, 2000), of which about one-third has been discovered.

Figure 2.3
Principal Producing U.S. Coalbed Methane Basins and Total Resource



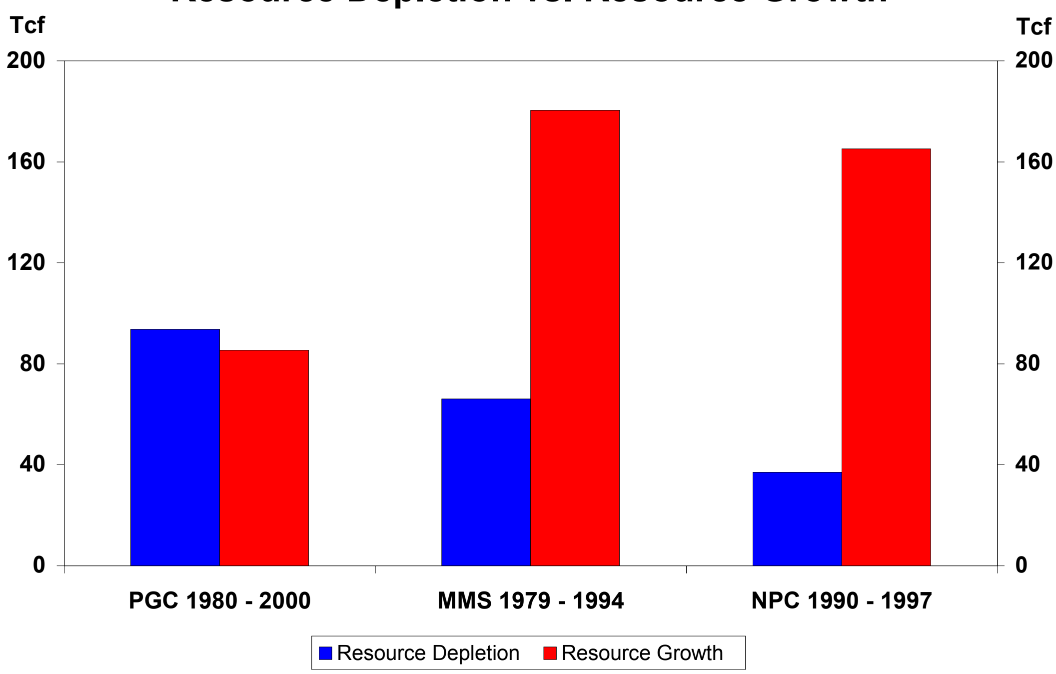
In the near-term, growth in the coalbed methane resource will depend more on improved recovery of coalbed methane-in-place. In the early 1990s, less than one-fourth of coalbed methane gas-in-place in Powder River Basin was expected to be recoverable. Current estimates expect almost three-fourths will be recovered. If recovery of gas-in-place could average two-thirds in the six principal producing basins, their recoverable resource could increase 20 Tcf.

Other coalbed methane basins with little or no production today may prove economic. The largest of these are the Northern Appalachian Basin (77 Tcf), Piceance (99 Tcf), and the Green River Basin (314 Tcf). Activity exists in all three basins, and it has begun to grow in the Greater Green River Basin. If even 10% of the coalbed gas-in-place could be recovered, this would be about 50 Tcf.

Western Gulf of Mexico

The "ultimate" gas resource in the Western Gulf of Mexico (offshore Alabama to Texas) has grown in the last 20 years. While a large part of this growth has been inclusion of gas resources in the Deepwater (>1,500 feet water depth), the Shelf (<600 feet water depth) resource has also grown. Figure 2.4 presents the dynamics of the Gulf of Mexico resource estimates for the three estimates.

Figure 2.4
Gulf of Mexico "Ultimate" Gas Resource Dynamics
Resource Depletion vs. Resource Growth



The PGC estimate of the "ultimate" resource in the Gulf of Mexico resource base "replaced" 91% of the "depletion" that occurred between 1980 and 2000. Over a 15-year period, the U.S. Government (USGS in 1979 and MMS in 1994) expanded their resource base almost three times the "depletion" that occurred between 1979 and 1994. The base PGC (1980) and U.S. Government (1979) estimates did not include Deepwater resources, but they did in the later assessments shown in Figure 2.4.

The NPC base (1990) estimate included a substantial Deepwater resource. Seven years later, the NPC expanded its Gulf of Mexico resource estimate more than four times the "depletion" of the Gulf of Mexico resource base between 1990 and 1997.

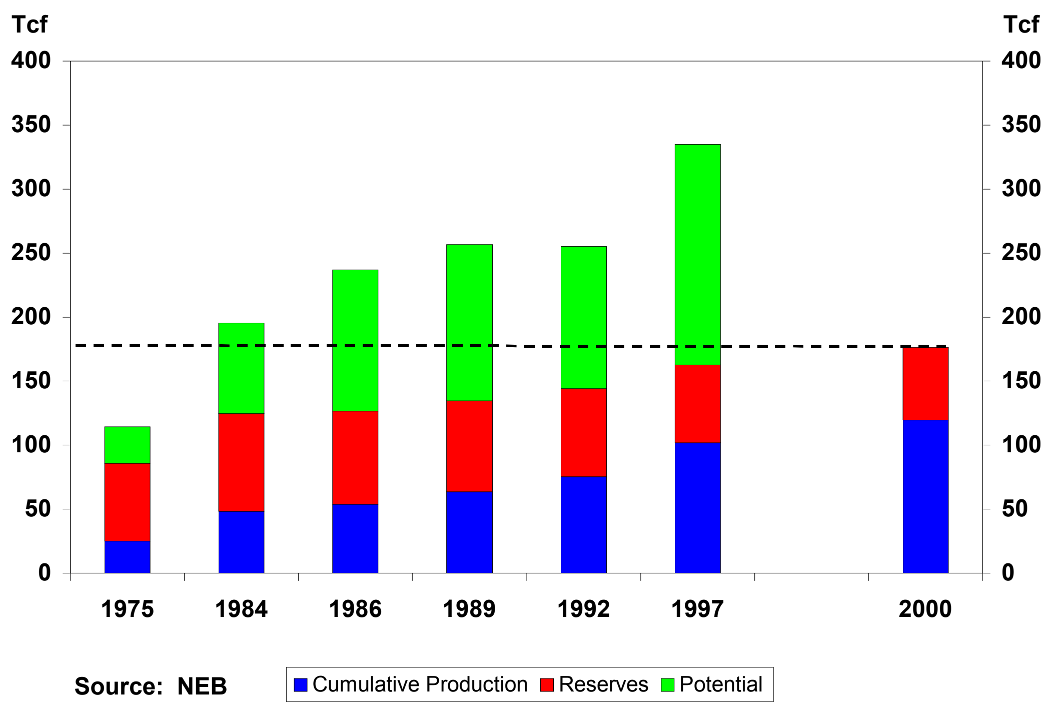
Prospects for continued growth in the Gulf of Mexico resource are good, even on the Shelf (<600 feet water depth). More than 90% of gas completions on the Shelf are above 15,000 feet, but significant discoveries have been made below 15,000 feet. Based on onshore observations of increasing sediment productivity with depth, the gas resource below the 15,000 foot drilling depth on the Shelf could be substantial. Because deeper drilling on the Shelf has often been quite expensive and risky, large-scale development of deeper Shelf sediments could depend on new technology.

Continued Deepwater activity should probably lead to upward revisions in the Deepwater gas resource base, just as activity in the much more heavily explored and developed onshore regions has continued to expand the onshore resource base over the last 25 years.

Western Canada Resource Dynamics

Figure 2.5 presents the trends in resource estimates used by the National Energy Board (NEB) of Canada for Western Canada since 1975. These estimates *do not* include unconventional sources.

Figure 2.5
WCSB Conventional Gas Resource Estimate Dynamics



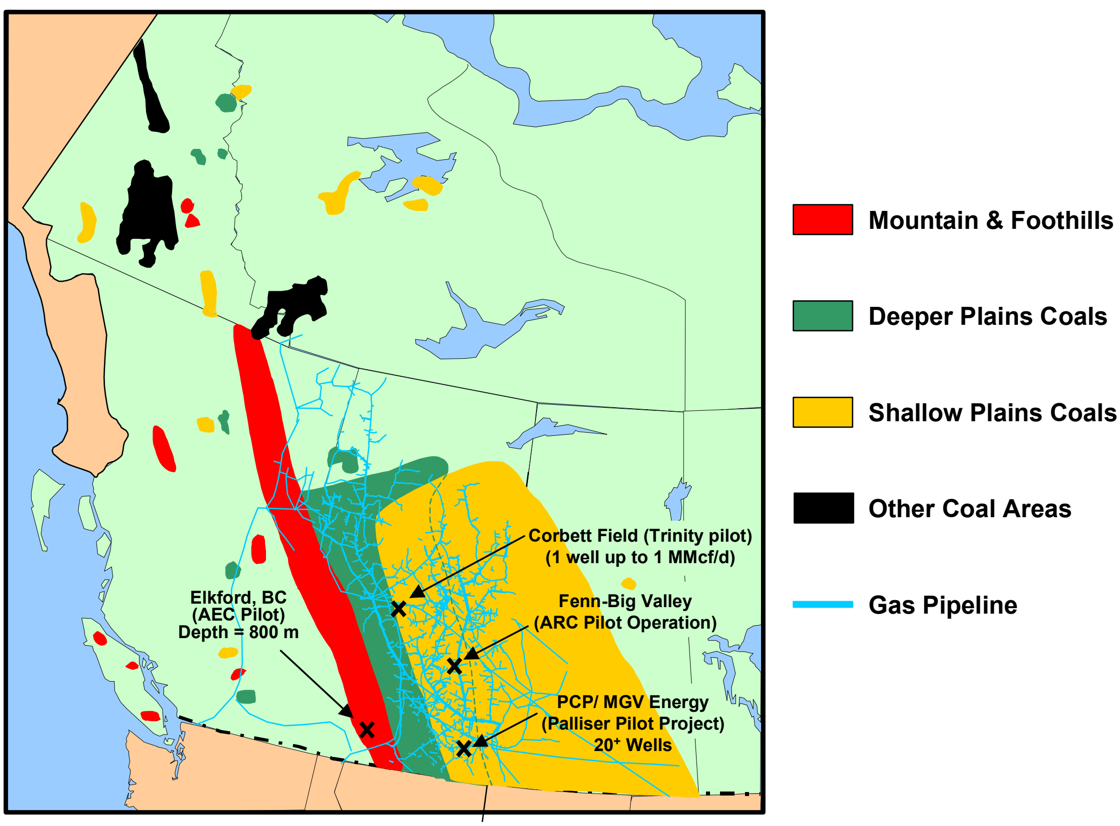
Source: NEB

"Ultimate" gas resource estimates for Western Canada have grown substantially in the last 25 years. The most recent estimate of 335 Tcf (1997) is 2.7 times larger than the 1975 estimate and 30% larger than the 1992 estimate. Canadian discoveries through 2000 are almost 50% higher than the 1975 estimate of the "ultimate" recoverable gas resource and could exceed the 1984 estimate by 2005.

Growth in the "ultimate" conventional Western Canada gas resource could continue. Western Canadian gas exploration and development activity has been concentrated in the shallower sediments of Alberta and Saskatchewan. Discoveries in the Fort Liard area (southern Northwest Territories) and in the deeper sediments of British Columbia and Western Alberta indicate that *conventional* activity in Western Canada is shifting to the West and North. The recent large Ladyfern discovery on the northern British Columbia/Alberta border may be an indicator of future results.

Coalbed methane is a wild card in Western Canada resource prospects. Pilot projects in coalbed methane have been undertaken, and initial results have been positive. Based on the pilot project results, PanCanadian is accelerating its coalbed methane activity. Figure 2.6 shows potential coalbed methane areas in Western Canada and the principal gas pipelines.

Figure 2.6
Potential WCSB Coalbed Methane Regions



There are four general coalbed methane areas, Shallow Plains, Deeper Plains, Mountains and Foothills, and other coal areas are scattered throughout British Columbia and North of 60°. The Shallow Plains and Deeper Plains coals overlap in Central Alberta. Many coalbed methane projects are active in Western Canada, and four are indicated on the map. The Trinity pilot in the Corbett field has resulted in a coalbed methane well that showed promise of peaking at 1 MMcf/d.

Coal rank, which is an indicator of coalbed methane potential, *increases* moving from *East to West*. At the same time, the coal resource extends to a greater depth moving East to West. As a result, while the in-place coalbed methane resource increases moving in a westward direction, greater burial depths make recovery of a growing share of this resource uncertain.

Coals in the **Shallow Plains Area** extend from Saskatchewan almost to the Alberta foothills. Gas contents of these shallow coals are generally less than 50 cf/ton, analogous to Powder River Basin coals. Three of the four coalbed methane projects in Figure 2.6 are in the Shallow Plains coals.

The **Deeper Plains Area** coals extend to the Foothills of Alberta and British Columbia. A large part of this area underlies the Shallow Plains coals. Coal geology appears analogous to Black Warrior Basin coals. With the greater drilling depths and complex geology, costs of development are likely to be higher.

The **Mountains** and **Foothills Area** has bituminous coals with thickness up to 250 feet and gas contents often exceeding 200 cf/ton. The significant faulting in this area, however, may reduce gas recovery prospects in some parts of the area.

In some ways, knowledge of coalbed methane recovery in Western Canada today is comparable to knowledge in the United States in the mid-1980s before significant production developed. However, because of production experience to date in the United States, Western Canada coalbed methane prospects could develop more quickly.

While estimates of coalbed methane gas-in-place in Western Canada range up to about 2,700 Tcf of gas, a more reasonable estimate at this point in time and technology is about 500 Tcf, about 80% of which would be in Alberta. The recent NPC study estimated a recoverable coalbed methane resource in Western Canada of 74 Tcf, at most 15% of the gas-in-place. Based on U.S. experience, this may be too low a recovery factor. If only one-third of a 500 Tcf resource-in-place is recoverable, coalbed methane could provide about 150 Tcf of gas resources in Western Canada.

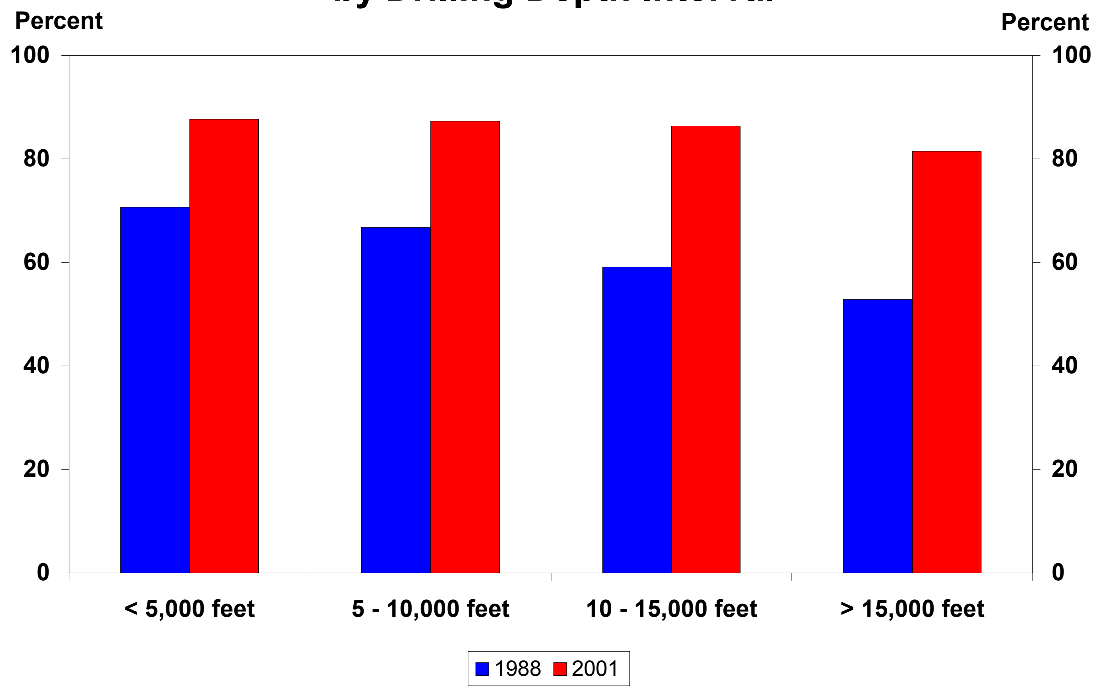
Technology Improvements

New technology has substantially reduced costs and risks associated with the exploration, development, and production of gas in North America during the 1990s. In addition, new technology has improved recovery from both conventional and unconventional resources. These advances have allowed industry to expand exploration in deeper sediments, “maintain” production in existing fields, and make production of unconventional resources economically attractive.

The average depth of a lower-48 gas well increased substantially in the 1990s. By the mid-1990s, it exceeded 6,400 feet, a new record. While the average depth has tailed off since 1997, this reflects the explosive growth of shallow coalbed activity in Powder River Basin of Wyoming. The *average depth* of a lower-48 gas well *excluding Wyoming* has continued to grow since 1998, *exceeding 7,000 feet in 2001*.

Success rates have improved substantially in the 1990s, substantially reducing the level of capital needed to develop new gas wells. Figure 2.7 shows success rates by drilling depth interval for 1988 and 2001. Success rates have improved for all drilling depth intervals, but the most dramatic improvements are for wells deeper than 10,000 feet. As a result of these improvements, the potentially rich deeper sediments, which hold the best prospects for large discoveries, now pose less of a risk to drill than did shallow sediments 20 years ago.

Figure 2.7
U.S. Drilling Success Rates
by Drilling Depth Interval



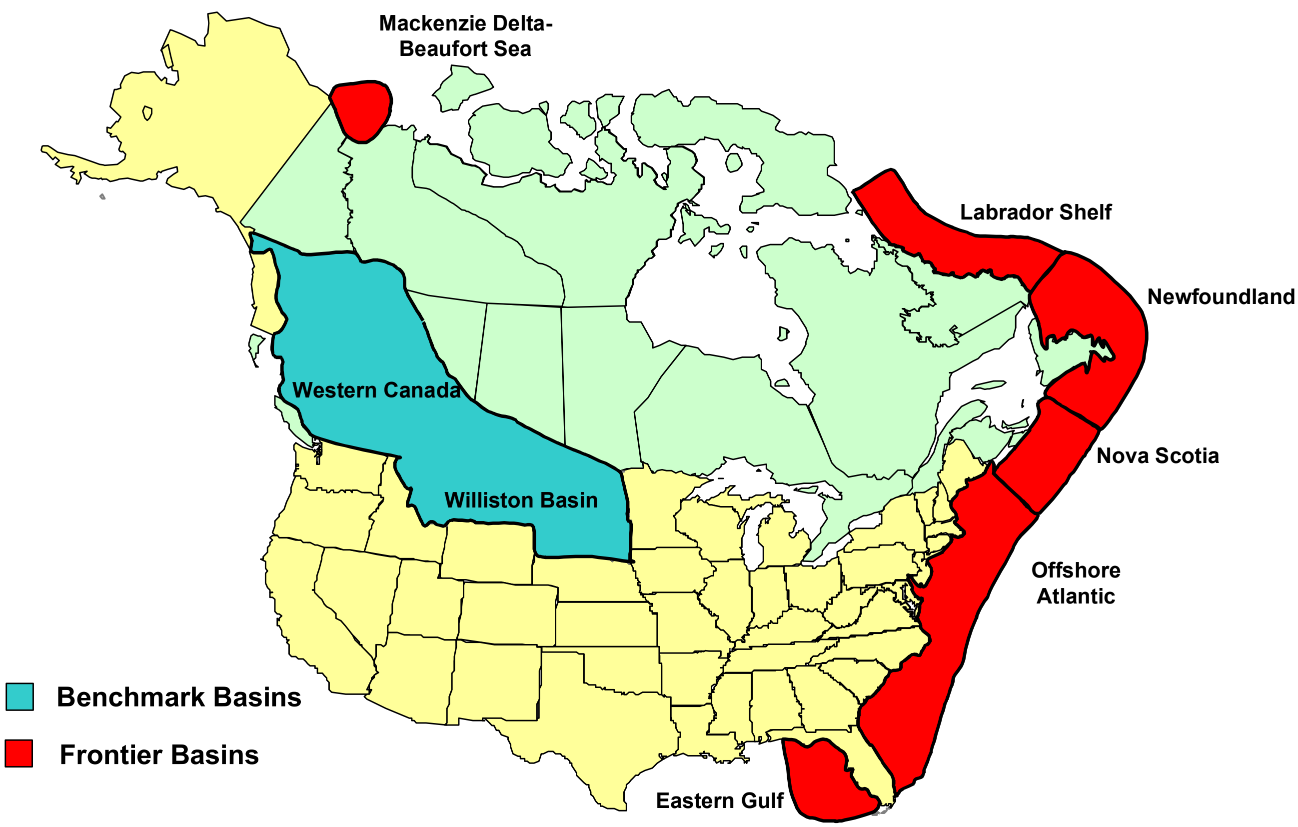
In 1988, wells in the 10-15,000 foot interval had an average, reported success rate of 59%, and wells deeper than 15,000 feet had an average success rate of 53%. In 2001, current data indicate that success rates for these drilling depth intervals were 86% and 82% respectively.

Improved success rates have been quite pronounced for wildcat wells. Between the mid-1970s and late 1980s, wildcat success rates were in the 15-20% range. Since 1988, wildcat success rates have more than doubled. In 2001, they are estimated to exceed 38%. Coincident with the improving success rates, the average depth of a wildcat well has grown substantially, averaging a record 8,400 feet in 2001, indicating that exploration of deeper sediments is very attractive. Because deeper sediments in producing regions have the best prospects for large discoveries, this deepening exploration activity could lead to growth in "ultimate" gas resource estimates for producing regions.

Frontier Regions

Although the lower-48 and Canada are very heavily explored, frontier regions still exist. Figure 2.8 illustrates these frontier regions. Also shown are Western Canada and the lower-48 Williston Basin regions, which will be used to benchmark current resource estimates.

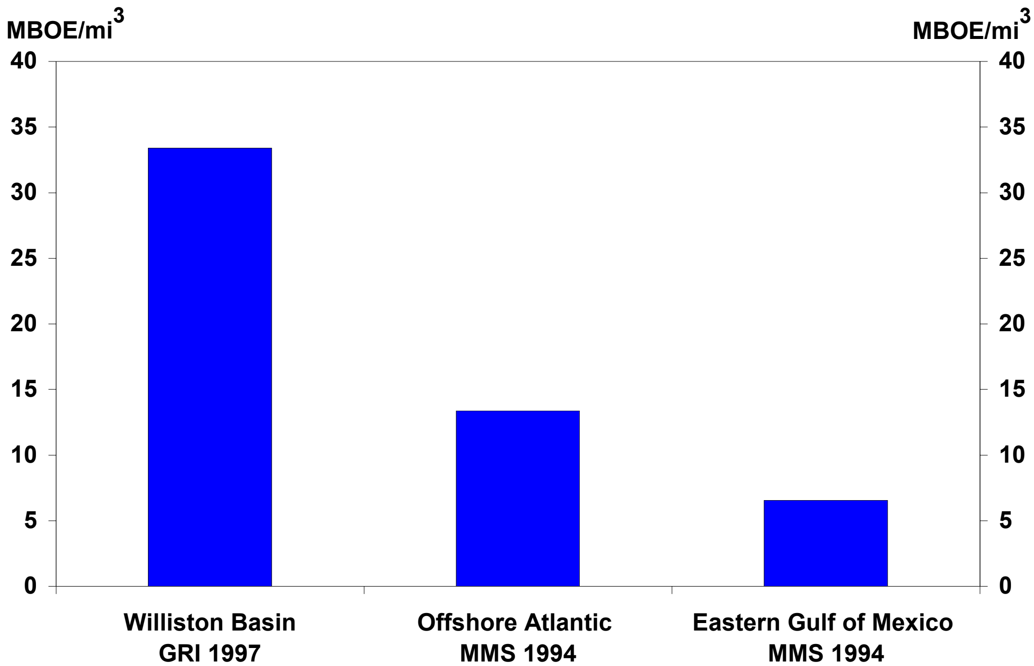
Figure 2.8
Lower-48/Canada Frontier and Benchmarking Regions



While "ultimate" resource estimates for frontier regions are very uncertain, they can be benchmarked against other relatively well-developed onshore regions using sediment volume yields (MBOE/mi^3). Such benchmarking can indicate whether industry activity in these regions might lead to increases in current estimates of "ultimate" recovery. Because the Williston Basin region in the lower-48 is the least productive, lower-48 producing region, it provides a benchmark for the conservatism of a resource estimate.

Figure 2.9 compares the sediment yield of the Williston Basin to sediment yields of the Offshore Atlantic and the Eastern Gulf of Mexico. The Williston Basin resource is taken from the 1997 GRI Baseline Projection; the Offshore Atlantic and Eastern Gulf of Mexico resources from the MMS estimate as of 1995.

Figure 2.9
"Productivity" of Frontier Lower-48 Regions

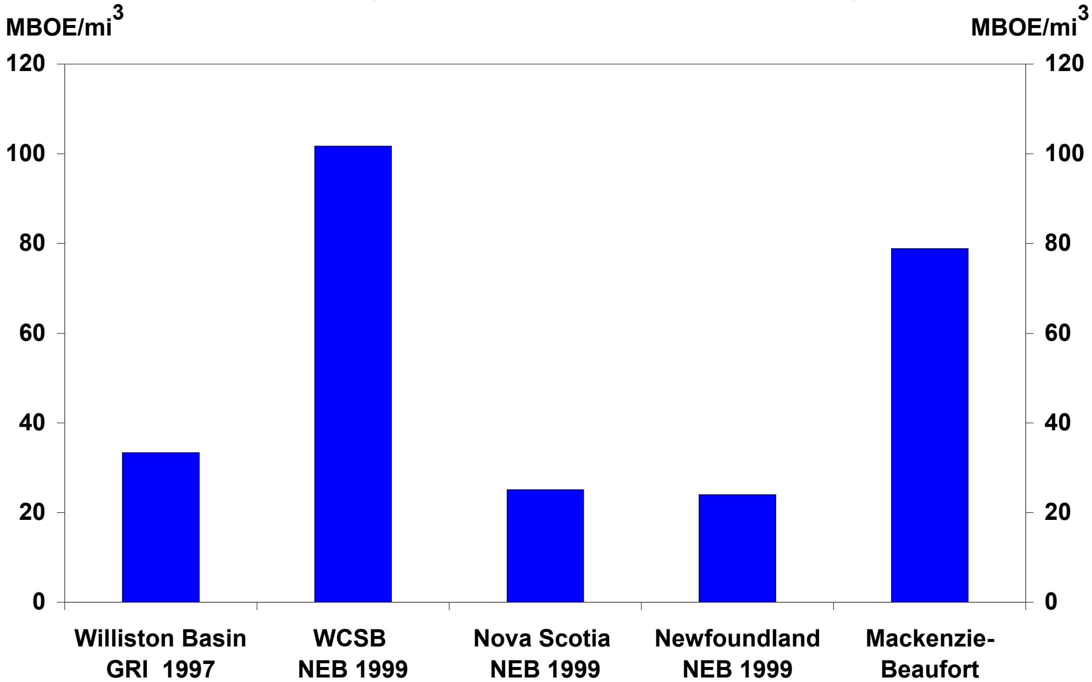


The Williston Basin sediment productivity is three times that of the Offshore Atlantic and six times that of the Eastern Gulf of Mexico. This ranks the Offshore Atlantic and Eastern Gulf of Mexico regions as the poorest regions in the lower-48.

The low yields of the two frontier basins imply the absence of giant fields (> 800 MMBOE) that could serve as an anchor to begin development. Because these are offshore basins, current "ultimate" resource estimates suggest that their economics are marginal at best. The drilling moratoria in the Offshore Atlantic and Eastern Gulf of Mexico imply a strong possibility of significant economic production being developed to the detriment of the environment. This would not be likely without an "ultimate" resource, an order of magnitude, or larger than current estimates.

Canadian assessment methodologies generate higher "ultimate" resource potentials for frontier areas, but these resource potentials still appear quite conservative. Figure 2.10 presents sediment yields of the four principal frontier Canadian regions. Yields for the Williston Basin and Western Canada are presented for reference. The Canadian resource estimates are taken from the most recent NEB long-term energy outlook.

Figure 2.10
"Productivity" of Frontier Canadian Regions



With the exception of the Mackenzie Delta/Beaufort Sea region, frontier Canada basins look quite poor compared to Western Canada. In fact, Nova Scotia and the Labrador Shelf have poorer sediment yields than the Williston Basin, and Newfoundland a sediment yield only slightly larger than the Williston Basin, although it already has one giant field, Hibernia (1.2 billion BOE). Given the large discoveries to date in these frontier regions, current estimates of "ultimate" gas resources will probably grow substantially as industry activity continues.

Prospects for Future Resource Growth

Over the last 20 years, estimates of lower 48 and Canadian gas resources have grown more than the resource has been depleted. As a result, the remaining resource potential today is much higher than it was 20 years ago, despite resource depletion.

Prospects for continued growth in "ultimate" resource estimates at or ahead of the depletion of the resource appear good. Deeper sediments both in the onshore and Gulf of Mexico Shelf provide a new frontier for exploration and development in the "mature" producing areas. The Western Canada "ultimate" resource estimate should also grow substantially once unconventional gas resources are included. In the lower-48, some new coalbed methane basins may become productive in the coming decades, and recovery of in-place unconventional resources could continue to improve.

Resource prospects for the lower-48 frontier regions (Offshore Atlantic and East Gulf) could be significantly larger than current estimates, but industry activity would be needed to demonstrate this. "Ultimate" resource estimates for frontier regions in Canada also appear understated. Large discoveries to date in Nova Scotia, Labrador, and Newfoundland are not consistent with regions whose sediment yields are comparable to or much less than the Williston Basin in the lower-48.

Table 2.1 summarizes the possible growth in "ultimate" gas resource estimates that might develop over the next 20 years in the lower-48 United States and Canada as a result of industry activity.

Table 2.1
North American Gas Resource Growth Prospects (2000 - 2020)

	Growth (Tcf)	Comments
Lower-48 Total	**500-1,200**	
Lower-48 Producing	**300 - 600**	
Onshore	200 – 400	Coalbed methane/shale could provide 100+ Tcf. Drilling moves into deep sediments. Appalachian Basin is a sleeper.
Western Gulf	100 – 200	Continued growth in Deepwater activity. Deeper Shelf sediments prove productive.
Lower-48 Frontier	**200 – 600**	
East Gulf	100 – 300	Necessary for East Gulf to be economic
Atlantic	100 – 300	Necessary for Atlantic to be economic
Canada	**400 - 900**	
Western Canada	100 - 300	Alberta/BC more productive than Saskatchewan. Coalbed methane provides 100^{+} Tcf
Sable Island	50 - 150	Based on discoveries to date
Newfoundland/Labrador	150 - 250	Based on discoveries to date
Mackenzie/Beaufort	100 - 200	Based on discoveries to date

While the resource growths appear significant, particularly at the upper end of the range, they are slower than the observed growth rates of "ultimate" resource estimates over the past 25 years for most areas. The growth in the lower-48 producing areas of 300-600 Tcf is about a 15-30% growth over the next 20 years. This growth is not excessive unless the modest activity to date in deep sediments has effectively identified almost **all** the significant gas prospects that can be found.

About half of the incremental prospects in the lower-48, however, rely on activity in the Eastern Gulf and Offshore Atlantic. While future activity might identify such resource prospects, activity in these areas *will not guarantee* that this resource range would actually prove out. These areas may truly prove to have as few prospects as current estimates indicate. But, then drilling moratoria would not be necessary because after a few wells, activity would effectively end.

Growth prospects for the "ultimate" Canadian resource are larger than for the lower-48. In Western Canada, current "ultimate" resource estimates indicate that sediment yields in Manitoba/Saskatchewan are better than for Alberta/British Columbia, which is not likely to last as activity moves into the deeper sediments of Alberta/British Columbia and if the coalbed methane resource proves significant. Sufficient activity has occurred in the frontier Canadian regions to strongly suggest that current "ultimate" resource estimates are too modest. As industry activity continues in these frontier regions, substantial upward adjustments to the "ultimate" gas resource are likely to occur.

Prospects for continued growth in the "ultimate" resource estimates for the lower-48 and Canada are very good. The critical question is whether the growth in resource expectations can keep pace with the resource depletion that will occur as a 30 Tcf gas market develops. This question will be addressed in the following chapters.

CHAPTER 3

LOWER-48 ACTIVITY

LOWER-48 ACTIVITY

Introduction

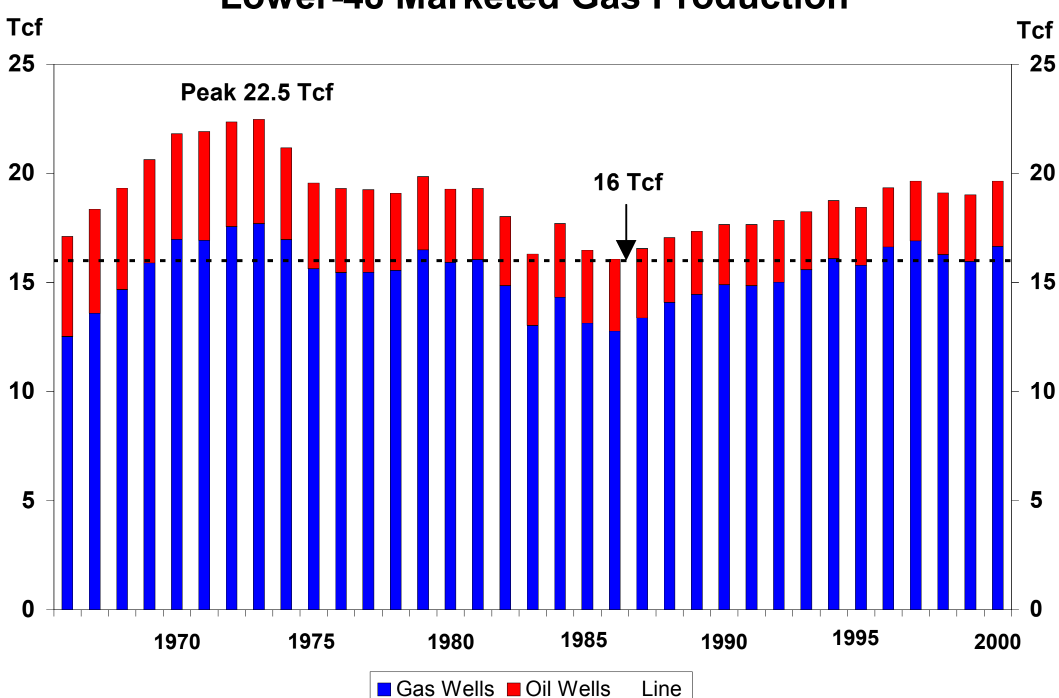
Since 1986, lower-48 gas production has recovered, possibly exceeding 20 Tcf in 2001. The recent NPC study projected that lower-48 gas production could exceed 26 Tcf by 2015 in its reference case, and the Department of Energy, Energy Information Administration (EIA) 2002 Outlook projected that lower-48 gas production could exceed 28 Tcf by 2020 in its reference case.

Recent events, however, have tempered this optimism. Despite surging gas drilling activity, lower-48 gas production has shown little growth since 1996. This chapter will review long-term trends in lower-48 gas production, reserves, drilling activity, and the yields of that drilling activity. Production and reserves data will be discussed on a marketed (wet) basis before extraction of gas liquids by gas plants *outside* producing leases. Dry gas production, which is delivered to customers, is 95.5% of marketed (wet) gas production (1979 - 2000 average).

Lower-48 Overview

Figure 3.1 allocates lower-48 gas production to gas wells (non-associated gas) and oil wells (associated gas). Lower-48 gas production peaked at 22.5 Tcf in 1973, with 21% (4.8 Tcf) coming from oil wells. In 1975, production declined below 20 Tcf and to 16 Tcf by 1986. While production has recovered since 1986, it has shown little growth since 1996, averaging 19 Tcf/yr.

Figure 3.1
Lower-48 Marketed Gas Production



Source: AGA/EIA

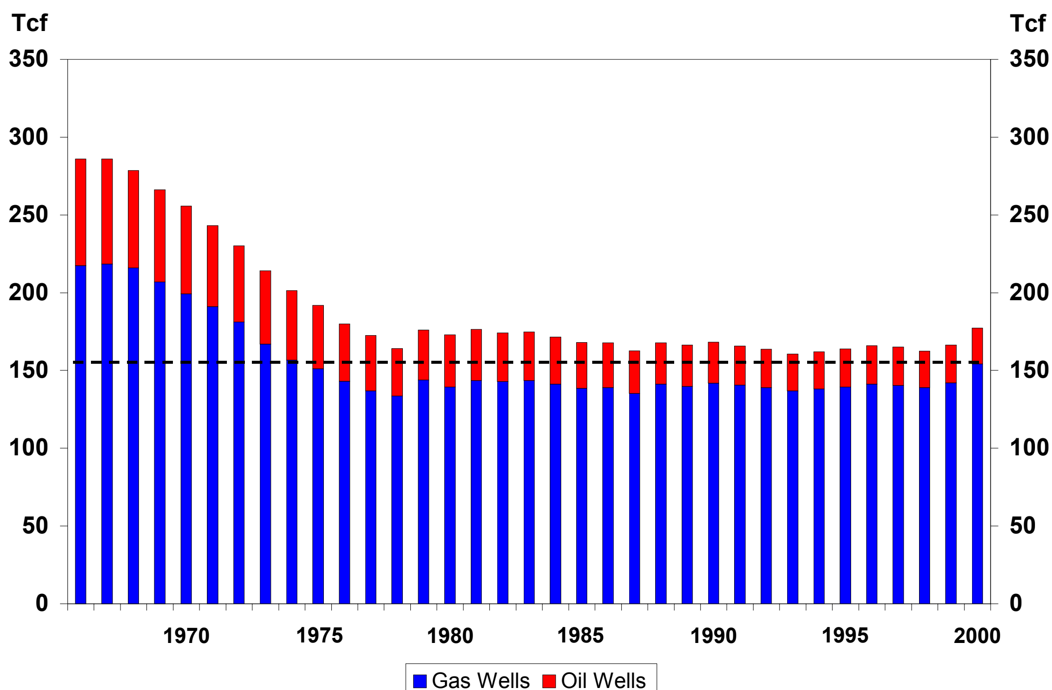
Almost two-thirds of the 2.8 Tcf decline in gas production between the 1973 and 2000 reflects lower associated gas production. By 2000, only 15% of lower-48 gas production came from oil wells. However, with the expected growth in associated gas production in the Deepwater Gulf of Mexico, associated production might stabilize or even grow in the coming years. *Non-associated production in 2000 was 16.7 Tcf (45.8 Bcf/d), comparable to its 1974 level.* Given the growth in gas production *in 2001, lower-48 non-associated production might be the highest since the peak years of 1972-73.*

Prospects for future lower-48 gas production will be reviewed in light of trends in gas reserves, drilling activity, and yields of that activity. Reserves and drilling activity provide an indication of near-term gas production prospects, and yields of drilling activity an indication of the "costs" to develop new production.

Lower-48 Reserves

Figure 3.2 presents lower-48 marketed gas reserves since 1966. Gas reserves declined more than one-third between 1966 and 1976. A modest decline continued into the 1990s, with that entire decline due to a fall off in oil well reserves. By 1999, only 15% of lower-48 gas reserves were associated gas, compared to a quarter (24%) in 1966.

Figure 3.2
Lower-48 Marketed Gas Reserves



Source: AGA/EIA

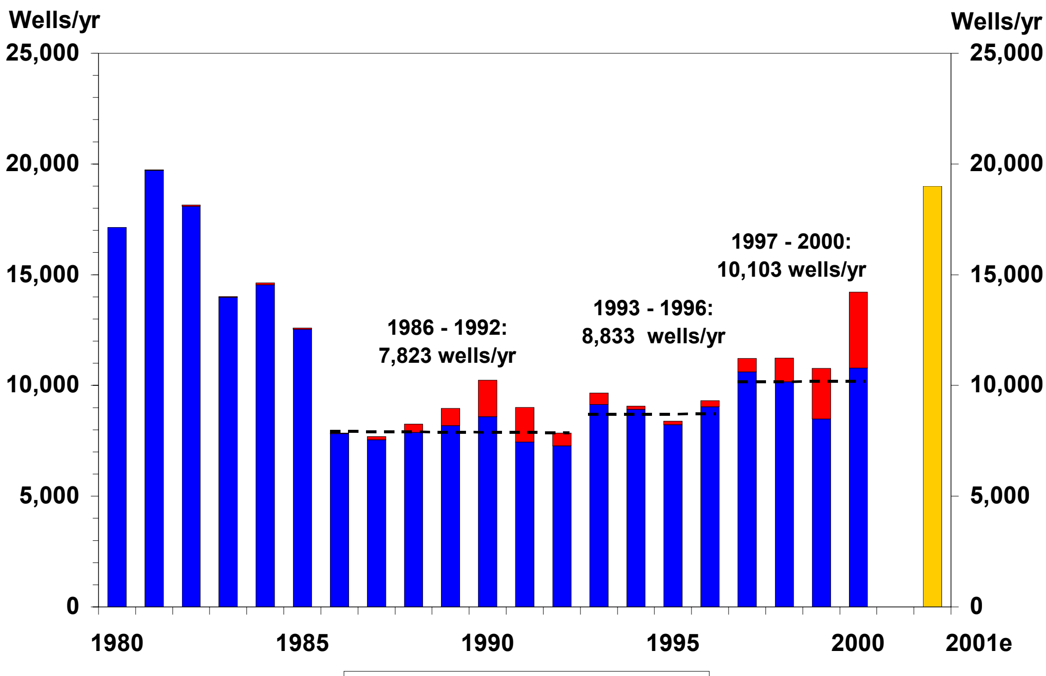
On the other hand, *non-associated reserves have not declined since 1976.* Non-associated reserves were at their highest level since 1974. A major contributing factor to the stability and growth in non-associated reserves since 1976 has been *coalbed methane production*. Currently, 10% (15.7 Tcf) of non-associated reserves and 8% of non-associated production is coalbed methane.

The RP ratio for non-associated gas has increased since 1996, suggesting additional gas deliverability might be obtained from current reserves. The RP ratio for non-coalbed methane wells is comparable to or better than 1976-81 levels, when non-associated production averaged 15.8 Tcf/year, 0.5 Tcf (1.4 Bcf/d) more than 2000 non-coalbed gas well production. Thus, non-coalbed methane gas well reserves might support more than 1 Bcf/d of additional non-associated production.

Drilling Activity

Gas drilling activity provides a leading indicator of future non-associated reserves and production. Figure 3.3 presents gas drilling activity since 1970 allocated to coalbed methane and non-coalbed methane gas wells.

Figure 3.3
Lower-48 New Gas Wells



Source: API

Annual new gas well completions have varied by more than a factor of two over the last 20 years. Drilling activity surged in 2000, reaching almost 16,000 new gas wells, the fourth highest level ever. Although drilling activity tailed off in late 2001, the number of new gas wells completed in 2001 probably exceeded 19,000, almost a new record. A major share of this surge was coalbed methane activity in Wyoming.

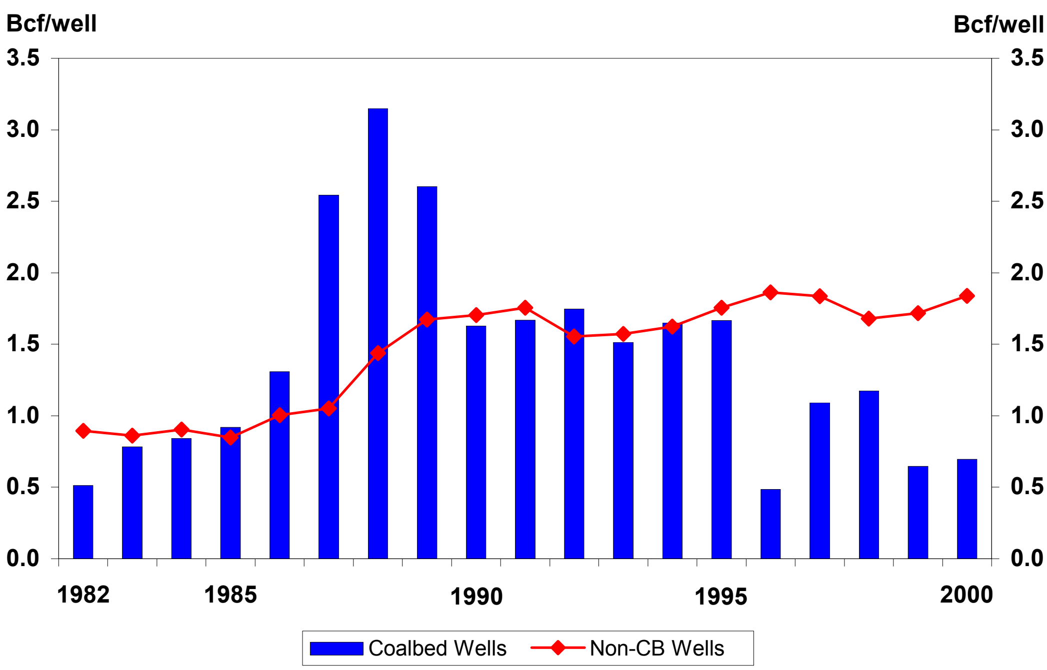
Coalbed methane drilling activity became noticeable in the late 1980s as a result of the Section 29 tax credits and technology advances. New coalbed methane well completions peaked at about 1,600 wells/year in 1990-91, but tailed off sharply after 1992 with expiration of the tax credit. By 1995, less than 200 new coalbed methane wells were completed. Since 1995, coalbed activity has surged again, exceeding 3,000 wells in 2000 and approaching 4,000 wells in 2001. *This growth has* *occurred without the tax credit.* While most of this growth has been in Powder River Basin, activity has also grown in the Uinta (Utah) and the Raton (Colorado/New Mexico) basins.

Non-coalbed methane gas wells have grown since the mid-1980s, but this growth has been slower, passing through three plateaus. Between 1986 and 1992, reported new, non-coalbed gas well completions averaged 7,823 wells/year. Between 1997 and 2000, they averaged 10,013 wells/year. More than 15,000 new non-coalbed methane gas wells may have been completed in 2001.

Reserve Additions Per Well

Figure 3.4 presents yields (reported non-associated reserve additions per new gas well) of industry activity since 1979. Because of the annual volatility, they are presented on a *cumulative* four-year basis. Yields are presented separately for coalbed methane and non-coalbed methane gas wells.

Figure 3.4
Lower-48 Reported Gas Reserve Additions per New Gas Well



Through the mid-1990s, reported reserve additions per coalbed methane well were comparable to or better than reported reserve additions per non-coalbed well. This reflected the rich coalbed methane fairway developed in the San Juan Basin. Since the mid-1990s, however, coalbed methane yields have dropped substantially, because activity shifted to lower yield-per-well basins (e.g. Powder River, Uinta, Central Appalachian). Yields of non-coalbed methane gas wells have grown modestly since the mid-1990s, averaging more than 1.8 Bcf/well between 1997 and 2000.

If yields remain near current levels, 19,000 new gas wells in 2001 could add as much as 25-30 Tcf of non-associated reserves. As a result, lower-48 non-associated reserves might grow about 10 Tcf in

2001. This would bring non-associated reserves to their highest level since the early 1970s, when non-associated production peaked at 17.7 Tcf, 1.0 Tcf higher than the 2000 level.

Implications

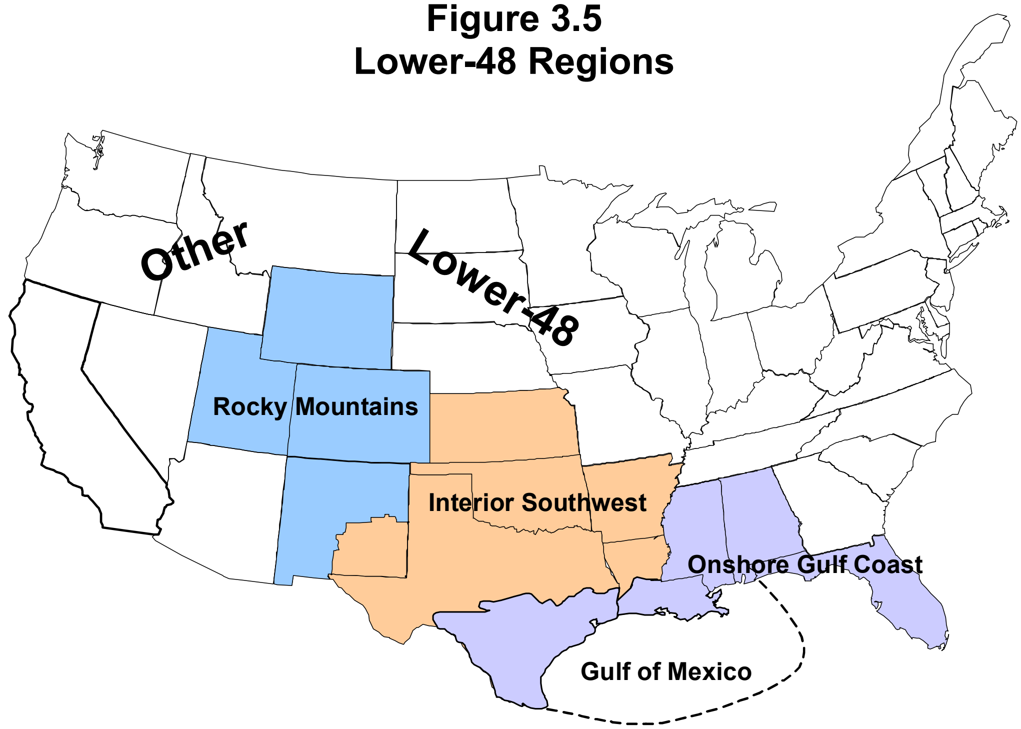
From a reserves and yield basis, prospects to maintain or increase lower-48 gas well production appear good. However, *accelerated declines in gas well production* since the late 1990s have increased demand for new gas wells above simple reserves replacement. The incremental demand for new wells has placed upward pressures on gas prices and will continue to do so until decline rates stabilize. Once decline rates stabilize, demand for new gas wells should decline to reserves replacement, reducing upward pressures on gas prices. At current non-associated gas production and yields, this could be less than 10,000 new gas wells. For non-associated gas production to grow, reserve additions should probably run at 10-20% above production.

Associated gas production has increased 9% since 1997, largely reflecting development of the oil-prone Deepwater Gulf of Mexico. While the extent to which this growth will continue is uncertain, lower-48 production will grow as much as non-associated production over the next few years and even more if associated production grows.

Regional Production Prospects

Prospects for increased gas production are not uniform across the lower-48. Production will be reviewed for five regions, Offshore Gulf of Mexico, Onshore Gulf Coast, Interior Southwest, Rocky Mountains, and the Remaining Lower-48. Figure 3.5 presents the lower-48 regions.

Figure 3.5
Lower-48 Regions

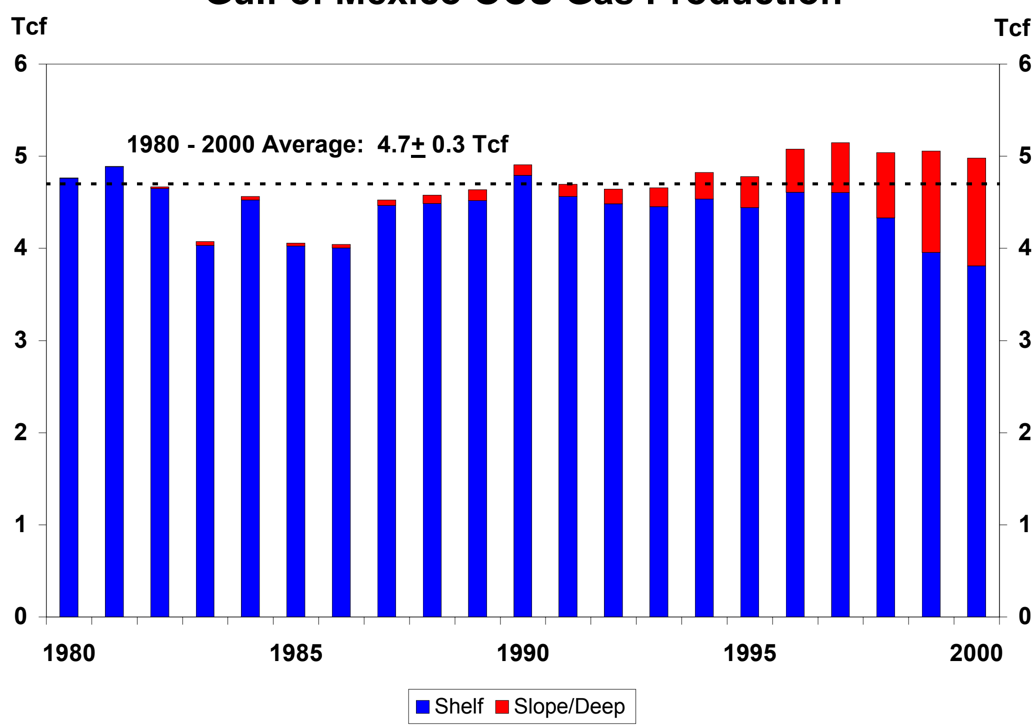


Gulf of Mexico

Gulf of Mexico production comes from state waters in Alabama, Louisiana, and Texas and the adjoining Federal Outer Continental Shelf (OCS). No production currently comes from the Eastern Gulf (offshore Florida). Gulf of Mexico gas production peaked in 1981 at 5.7 Tcf, 30% of lower-48 gas production in that year. Since 1981, Offshore Gulf of Mexico gas production has varied noticeably, but it has tracked lower-48 gas production closely (28.3% $\pm$ 1.0% of total production), regardless of offshore drilling activity and whether there was a "gas bubble" or tight supply.

Offshore Gulf of Mexico has two sub-regions, the Shelf (<200 meters water depth) and the Slope/Deepwater (>200 meters water depth). The Shelf has both state and federal waters. Slope production began in 1979, and Deepwater (>1,500 feet water depth) in 1988. Figure 3.6 allocates gas production to the Shelf and the Slope/Deepwater.

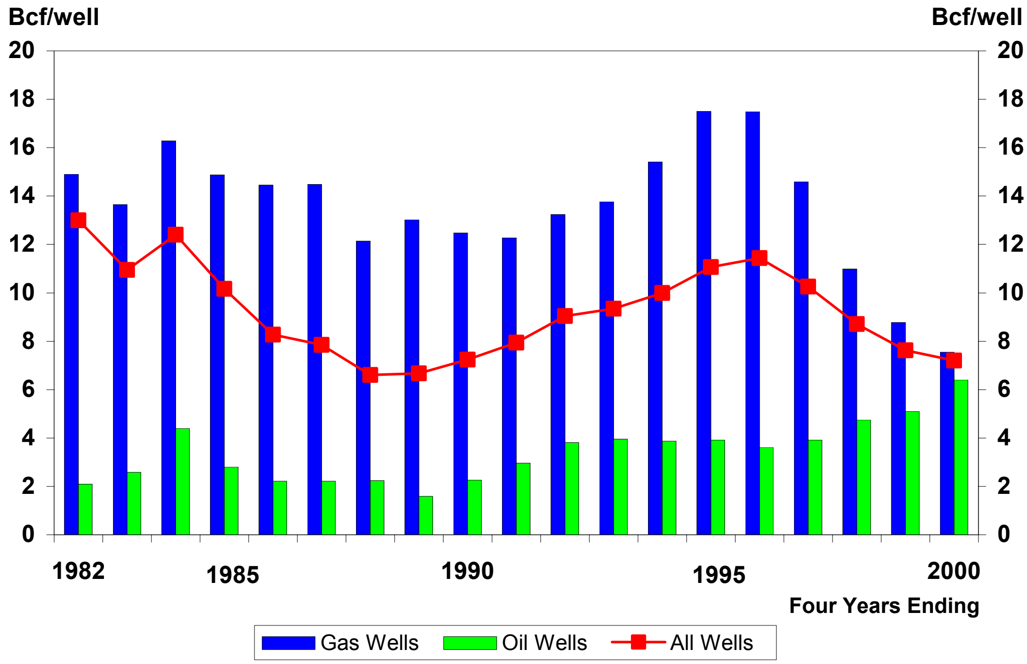
Figure 3.6
Gulf of Mexico OCS Gas Production



In 1990, almost all (98%) of Gulf of Mexico gas production came from the Shelf and by 2000, only three quarters (77%) came from the Shelf. Although Deepwater gas production should grow in the future, prospects for stability or growth in Shelf production are uncertain unless sediments below 15,000 feet prove productive. Substantial development of the deeper sediments, such as the subsalt play, will probably require advances in drilling and completion technology.

Figure 3.7 presents the yields of Gulf of Mexico drilling activity on a four-year cumulative basis since 1979. Because of the growing role of associated gas in the Deepwater Gulf, trends are presented for reported gas reserve additions per well for gas wells, oil wells, and all wells.

Figure 3.7
Gulf of Mexico Reported Gas Reserve Additions per New Gas Well



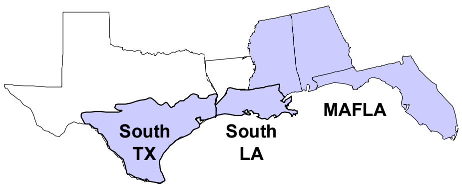
Yields of new Gulf of Mexico gas wells have declined by almost half in the late 1990s, standing at 7.5 Bcf/well for the 1996 - 2000 period. On the other hand, reported gas reserve additions per new oil well have more than doubled in the late 1990s, approaching yields of new gas wells. *Yields for all* industry activity (oil plus gas wells) in the Gulf of Mexico have *declined 22% in the late 1990s*.

Unless deeper sediments on the Shelf prove highly productive and can be aggressively developed, future growth in Gulf of Mexico gas production will depend on the gas reserve additions in the Deepwater. Because most Deepwater gas reserve additions are likely to be associated gas, future production in the Gulf of Mexico could increasingly depend on the level of oil drilling.

Lower-48 Non-Gulf of Mexico

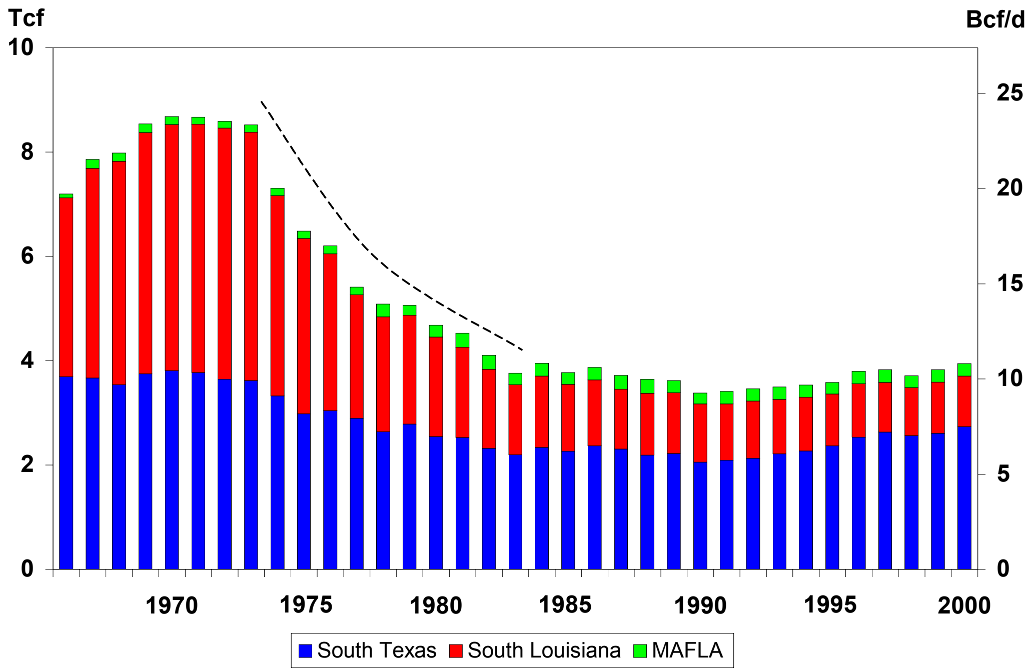
Non-Gulf of Mexico regions include the onshore lower-48 and offshore California. During the 1990s, lower-48 gas production increased two Tcf, and all of this growth came from outside the Gulf of Mexico. About 60% of this growth reflected coalbed methane production, and the rest growth in non-coalbed methane gas well production. Associated gas production declined in the early 1990s, but has been stable since 1994.

Onshore Gulf Coast



The Onshore Gulf Coast region is comprised of South Texas, South Louisiana, and MAFLA (Mississippi, Alabama, and Florida). Figure 3.8 allocates Onshore Gulf Coast gas production to these three regions. Gulf Coast gas production peaked in 1969 - 1973, averaging 8.6 Tcf per year. When lower-48 gas production peaked in 1972 - 1973, the Gulf Coast provided 39% of lower-48 production. When lower-48 gas production declined between 1973 and 1986, most of that decline occurred on the Gulf Coast. By 1986, only a quarter (24%) of lower-48 gas production came from the Gulf Coast.

Figure 3.8
Marketed Gas Production
Gulf Coast Onshore

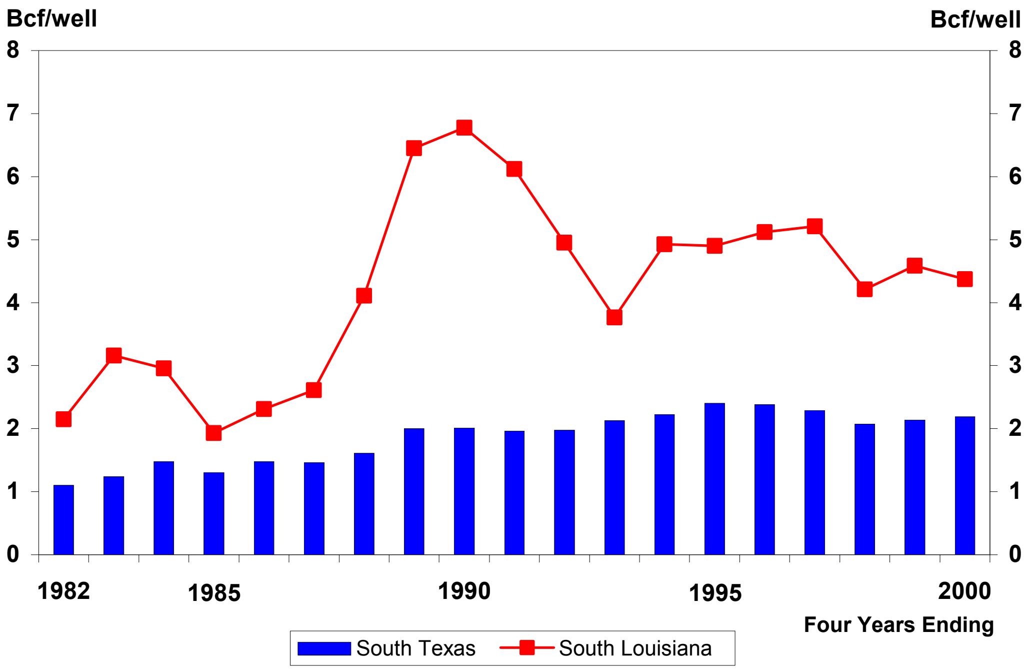


Although lower-48 gas production grew after 1986, Gulf Coast gas production continued to decline to 3.4 Tcf by 1990, down 60% from its 1973 peak, and representing 19% of lower-48 gas production. Since 1990, however, Gulf Coast gas production has stabilized and grown slightly, reaching 4.0 Tcf in 2000, 20% of lower-48 gas production.

Most of the Gulf Coast gas production comes from South Texas, and its production has grown one third since 1990, reaching 2.7 Tcf in 2000, its highest level since 1978. This reflects a return to near-record gas drilling activity and increased exploration of the largely unexplored sediments below 10,000 feet. Gas production in South Louisiana declined through 1997, but then stabilized following a modest recovery in gas drilling activity. Since 1997, South Louisiana gas production has been stable, averaging 955 Bcf/yr (2.6 Bcf/d). MAFLA gas production has grown less than 10% -- growth in coalbed methane production has more than offset declining non-coalbed production.

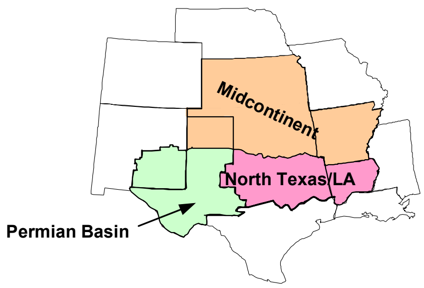
Figure 3.9 shows the yields for South Texas and South Louisiana, the principal producing areas of the Gulf Coast. South Texas yields have grown during the last 20 years, exceeding 2 Bcf/well for most of the 1990s. Current South Louisiana yields are more than double yields in the early 1980s.

Figure 3.9
Gulf Coast Reported Gas Reserve Additions per New Gas Well



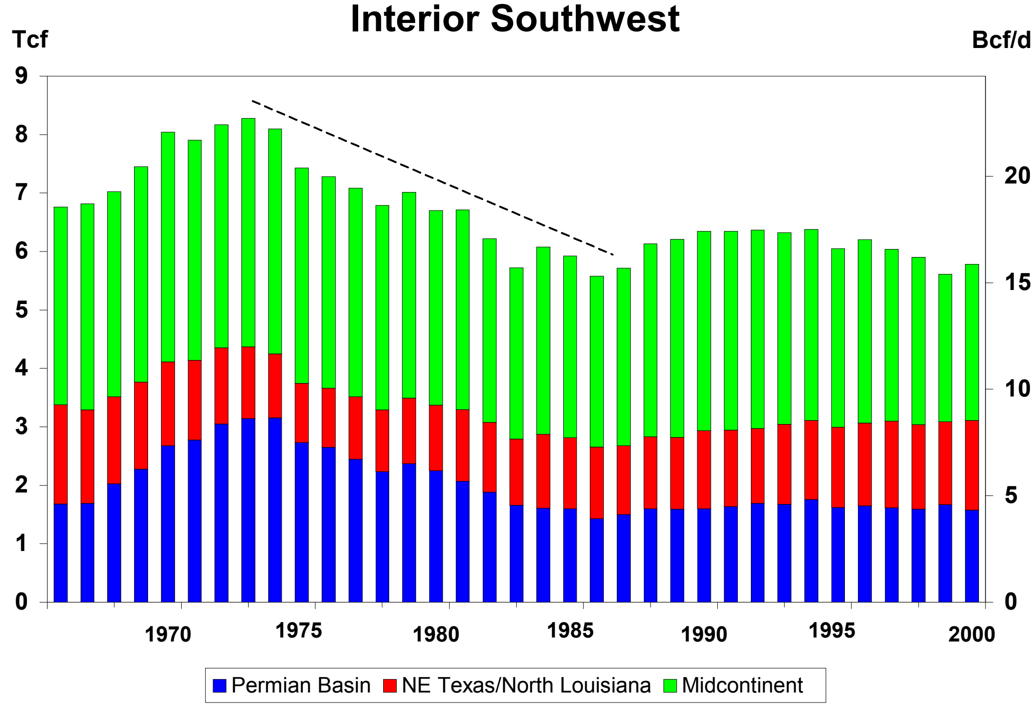
At current yields, only about 1,000 new gas wells would be needed to replace gas production in South Louisiana and South Texas. About 1,700 new gas wells were completed in these two areas in 2001. Therefore, drilling activity in the Gulf Coast area is at a pace that provides a good opportunity to expand reserves and increase production.

Interior Southwest



The Interior Southwest region consists of the Permian Basin, North Texas-Louisiana, and the Midcontinent. Figure 3.10 allocates Interior Southwest gas production to these three areas. Interior Southwest gas production peaked in 1973 at almost 8.3 Tcf, providing 37% of lower-48 production. While it declined after 1973, the decline was not a severe as on the Gulf Coast. By 1986, production was 5.6 Tcf, 35% of lower-48 gas production in 1986. Production recovered after 1986, reaching 6.4 Tcf in 1994, but it has fallen back to 5.8 Tcf as of 2000. In 2000, it only provided 29% of lower-48 gas production.

Figure 3.10
Marketed Gas Production
Interior Southwest

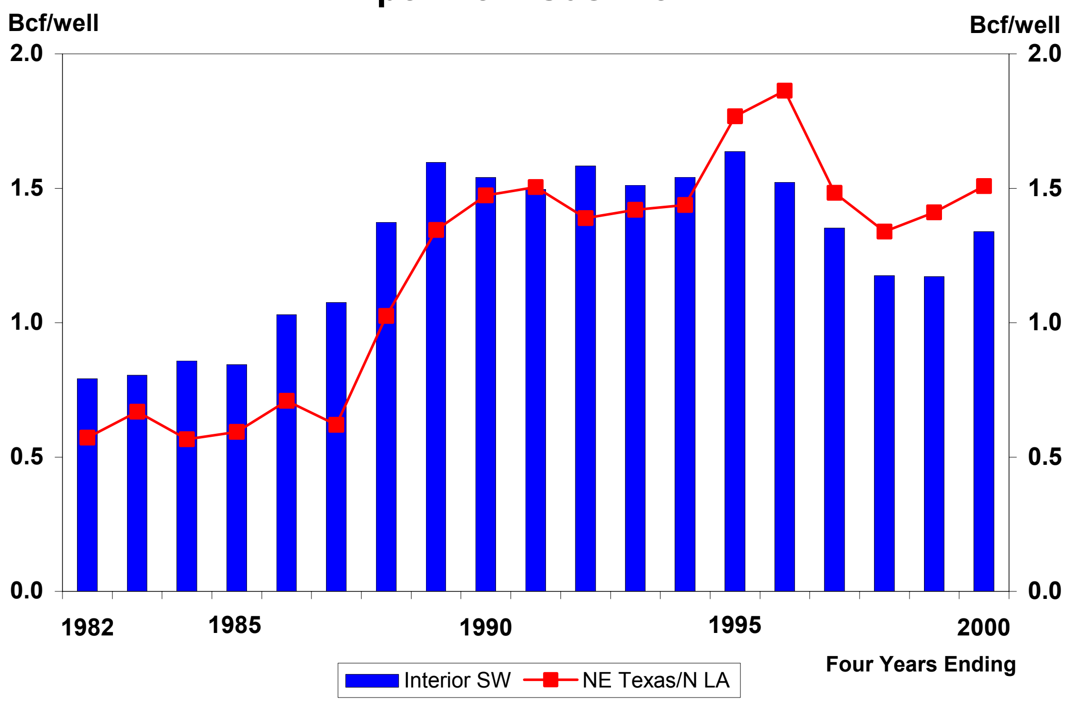


The Midcontinent accounts for almost half of the region's production. When Interior Southwest production peaked in 1973, the Permian Basin provided 38%, but the Midcontinent only provided a quarter (27%). Gas production in North Texas-Louisiana has grown substantially since the mid-1970s, and now produces almost as much gas as the Permian Basin.

The general, long-term trend in Midcontinent gas production has been downward since 1973. However, the decline in Permian Basin production ended in 1983. Since then, Permian Basin production has been very stable, averaging 1.6 Tcf/year, although oil and gas drilling activity has varied more than a factor of three since 1983. Production in North Texas-Louisiana has grown more than 50% since 1975, and its non-associated gas production and reserves are the highest ever.

Figure 3.11 shows the yields for the Interior Southwest region and the North Texas-Louisiana part of the region. Yields almost doubled in the region as a whole after the mid-1980s, and more than tripled in North Texas-Louisiana. Yields in the Interior Southwest have tailed off since the mid-1990s, but are still much higher than 15-20 years ago. This decline reflects decreasing yields in the Midcontinent, which are down almost a third since the mid-1990s. Yields in the Permian Basin have remained stable since the mid-1980s at about 50% more than 15-20 years ago.

Figure 3.11
Interior Southwest Reported Gas Reserve Additions per New Gas Well



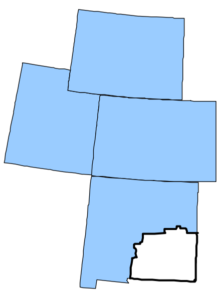
Yields in North Texas-Louisiana have remained near or above 1.5 Bcf/well during the 1990s. The higher yields reflect new technology that has improved tight sands recovery from deeper sediments. The average depth of new gas wells has increased from 5,100 feet in 1977 to 9,100 feet in 2000. The movement to deeper sediments continued in 2001, with the average depth reaching 9,400 feet.

At current yields, about 2,800 new gas wells would be needed in 2001 to replace gas production in the Interior Southwest region. More than 4,800 new gas wells were completed in this region in 2001. Therefore, drilling activity in the Interior Southwest area is at a pace to expand reserves and increase production in the near-term.

Over the longer-term, yields of gas drilling activity indicate limited prospects for sustained growth in the region as a whole. Although prospects for long-term growth in North Texas-Louisiana gas production appear good, declining yields in the Midcontinent indicate limited prospects for stability, let alone growth in Midcontinent gas production at this time. As a result, growth in North Texas-Louisiana gas production could continue to be largely offset by declines in Midcontinent production.

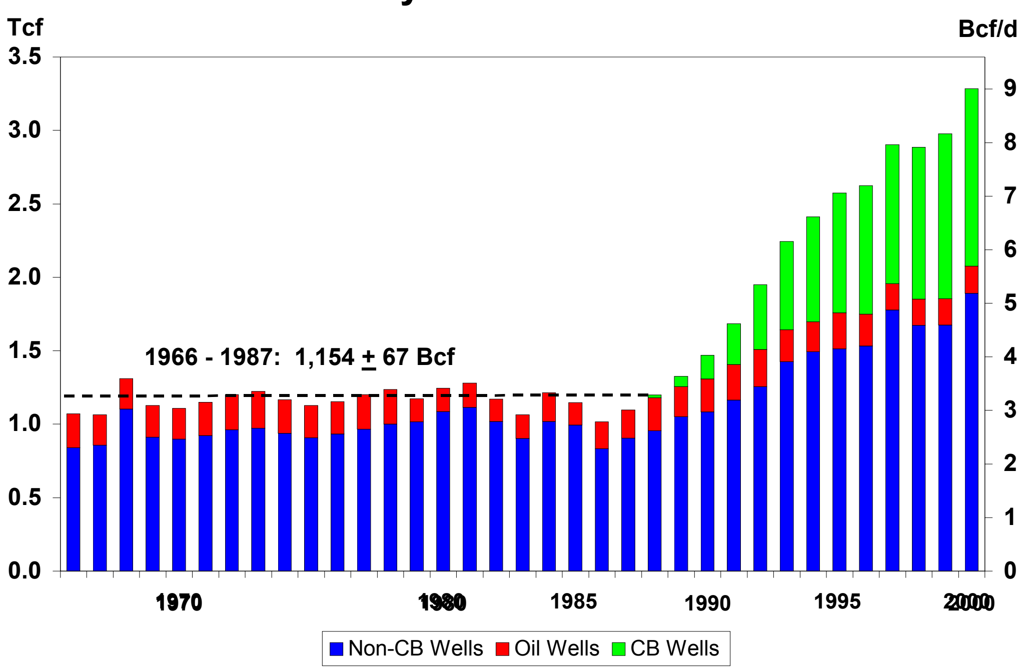
The critical uncertainty is the Permian Basin. While gas production in the Permian Basin has been very stable since 1983, production will probably begin to decline at some point in the next 20 years. The combination of long-term declines in Midcontinent production and the onset of declines in the Permian Basin at some point in the future suggest that *Interior Southwest production is likely to decline over the next 20 years*.

Rocky Mountains



The Rocky Mountain region extends from Wyoming to Northwest New Mexico. For more than 20 years, Rocky Mountain gas production was very stable, averaging 1,154 Bcf/year (3.2 Bcf/d). Production in the region almost tripled since 1988, growing from 1.2 Tcf to 3.3 Tcf in 2000. Production data to date in 2001 suggest that this growth is continuing. Figure 3.12 allocates Rocky Mountain gas production to gas, oil, and coalbed methane wells.

Figure 3.12
Marketed Gas Production
Rocky Mountain Basins



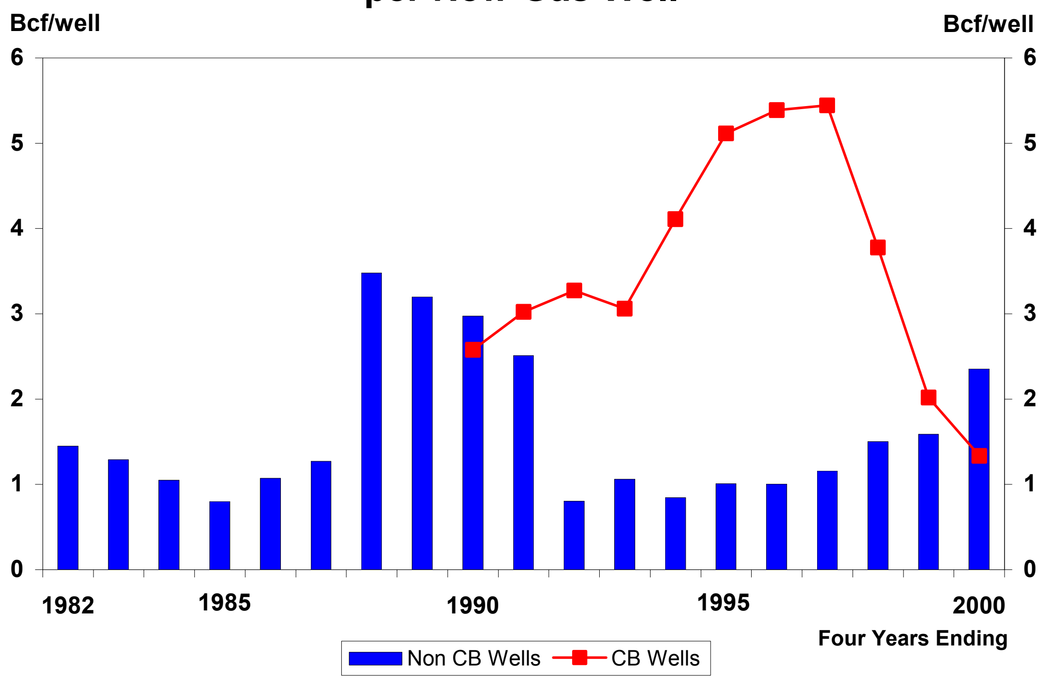
Most of the growth in production since 1988 was due to increased coalbed production, which grew 1.2 Tcf. The rest of the growth came from non-coalbed gas wells.

More than three fourths of Rocky Mountain coalbed methane in 2000 came from the San Juan Basin, but production began to fall off in 1999. Production from other basins has grown substantially in the late 1990s, particularly in Powder River and Uinta basins. Production in 2001 is on a pace to grow more than 300 MMcf/d. The Green River Basin is estimated to contain more than 300 Tcf of coalbed methane gas-in-place, and development is beginning in these coals. If Green River coals prove productive, coalbed methane production could grow substantially in the next 20 years.

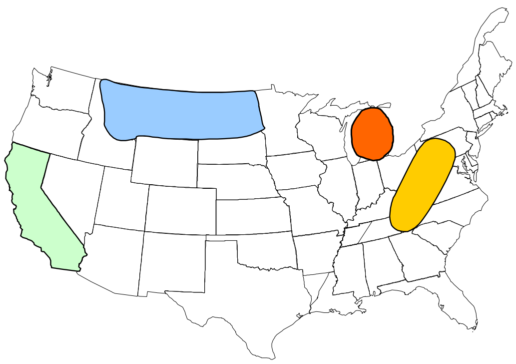
Non-coalbed methane gas production increased more than 900 Bcf (2.5 Bcf/d) between 1988 and 2000, in large part reflecting advances in tight sands technology. Significant non-coalbed methane prospects, particularly *tight sands*, remain to be developed in the Rocky Mountains. Further advances in technology should allow tight sands production to continue to grow.

Figure 3.13 shows the yields for the Rocky Mountain region for both coalbed methane wells and non-coalbed wells. Yields from non-coalbed methane wells grew during the 1990s, and now exceed 2 Bcf/well, comparable to recoveries in South Texas. Yields of coalbed methane wells peaked in the mid-1990s at more than 5 Bcf/well, reflecting the success in the San Juan Basin. Yields fell substantially in the late 1990s, reflecting the growing role of Powder River activity with low recoveries (more than 3,000 wells in 2000 with an estimated recovery of < 300 MMcf per well).

Figure 3.13
Rocky Mountain States Reported Gas Reserve Additions per New Gas Well

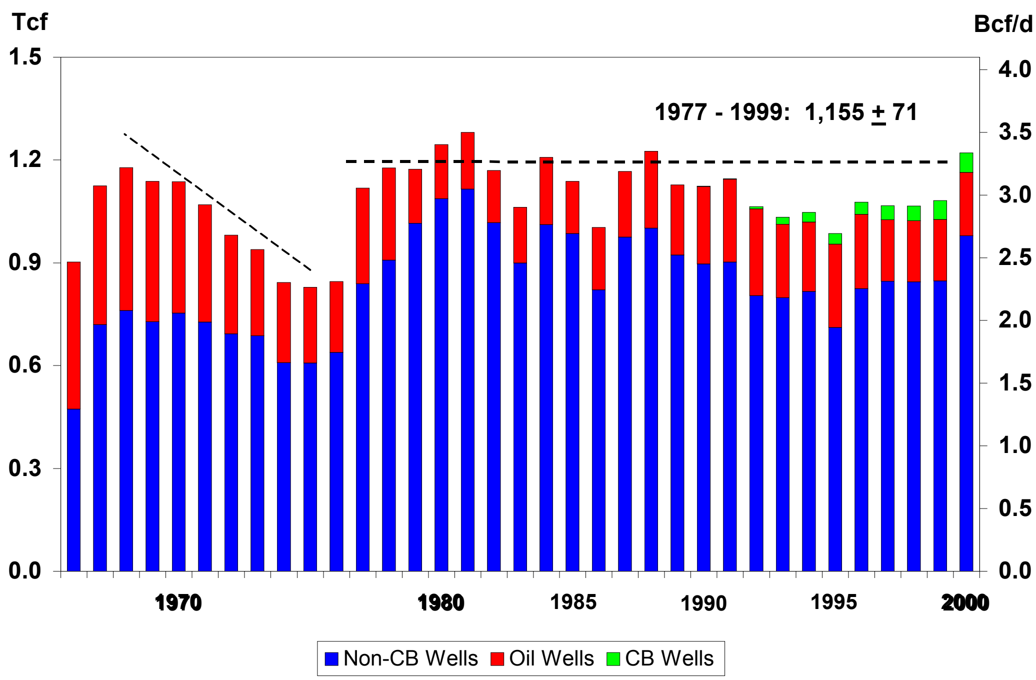


Other Non-Gulf Lower-48 Region



The Other Region is the remaining part of the lower-48, which includes the Appalachian and Michigan basins, the Northern Great Plains (Montana and the Dakotas), and California. The sources of production have changed significantly over the last 30 years. In the 1960s, most production came from California. Since the mid-1970s, most production has come from the Appalachian and Michigan basins. Figure 3.14 presents the trends Other Region gas production.

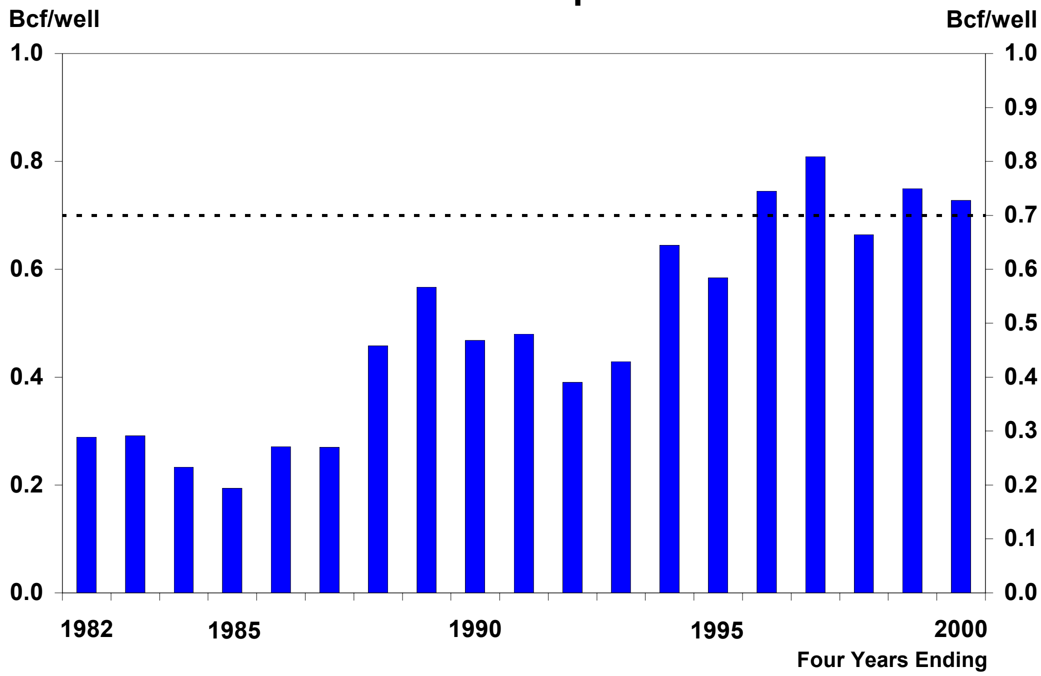
Figure 3.14
Marketed Gas Production
Other Non - Gulf Lower-48 Basins



The decline in Other Region production in the early 1970s reflected a large fall-off in California gas production. The recovery in the mid-1970s was principally driven by increased production in the Michigan and Appalachian basins. Since the mid-1970s, Other Region production has averaged 1,160 Bcf/year (3.2 Bcf/d). Production in 2000 grew, principally reflecting a surge in Appalachian Basin production. Growth has also occurred in Montana, and may continue with coalbed methane development in its portion of Powder River Basin. Coalbed methane production in the Appalachian Basin has begun to spread from Virginia into West Virginia. In 2000, coalbed methane production accounted for 6% of Other Region gas production.

Figure 3.15 presents the trends in reported non-associated gas reserve additions per new gas well in the Other Region. Yields have generally moved upward through two plateaus. During the 1990s, yields averaged 0.7 Bcf/well, almost triple their average through the mid-1980s. While average yields are the smallest in the lower-48, most producing areas in the Other Region are in consuming areas. As a result, their gas production receive higher prices than Gulf Coast or Rocky Mountain gas production. This higher price allows these wells to be economically attractive.

Figure 3.15
Other Lower-48 Basins Reported
Gas Reserve Additions per New Gas Well



Many of these areas, particularly the Appalachian Basin, have a substantial gas resource potential. However, much of this resource is in unconventional gas sources, such as tight sands, shale, and coal seams. Technology advances have opened up new resources in these areas, particularly the Antrim shale in Michigan and coalbed methane in the Central Appalachian Basin of Virginia and West Virginia. These areas produced almost 300 Bcf in 2000 (0.8 Bcf/d).

Coalbed methane activity in the Montana portion of Powder River Basin may become significant, with some assessments expecting as much as 1 Bcf/d. Canadian companies, who have very successfully developed the Canadian portion of the Williston Basin in Canada (it is almost three times more productive than the U.S. portion), are beginning to bring their expertise south.

Finally, some significant discoveries have been made below 10,000 feet in California, and California gas production has begun to recover as a result of these discoveries. Overall, prospects for stable to growing production in the Other Region appear good based on resource prospects and gas yields.

Final Observations

Yields have been quite stable to growing in most regions of the lower-48, with the most notable exceptions being the Gulf of Mexico Shelf and the Midcontinent. The stability of most yields support expectations for continued growth in the "ultimate" lower-48 resource expectations discussed in the previous chapter. The major downward uncertainty is the Gulf of Mexico Shelf. In this area, stabilization or some modest recovery of production will depend on large volumes of hydrocarbons existing in the deeper sediment on the Shelf and technology advances to reduce the cost and risks associated with bringing that deeper Shelf resource to market.

Based on gas yields and reserve additions, lower-48 gas production could grow, *if the economics are attractive*. While gas prices are likely to demonstrate *real* future growth as new natural gas resources are developed, upward pressures should be gradual (on average) over the long term. In *Fueling the Future*, the average price of natural gas at the wellhead grows to $3.60 (1999$) by 2020.

CHAPTER 4

CANADIAN ACTIVITY

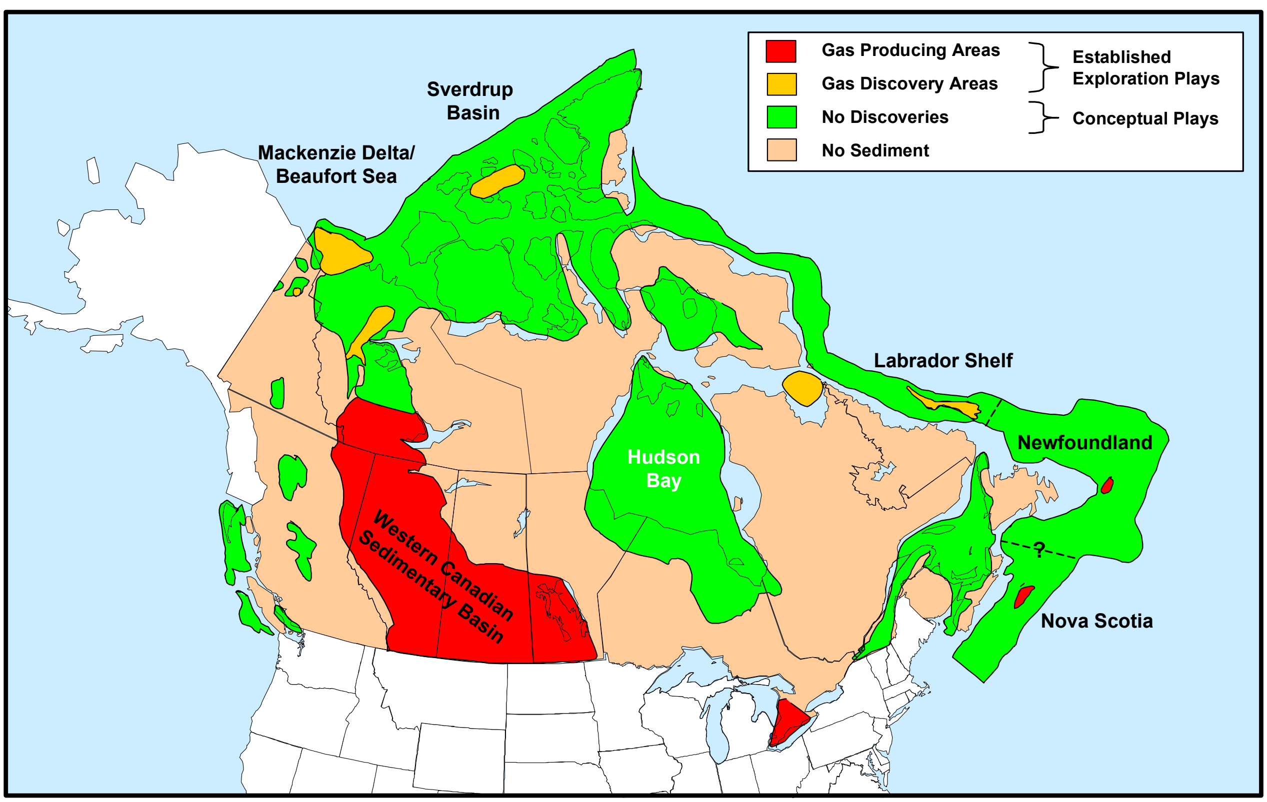
CANADIAN ACTIVITY

Introduction

Since the mid-1980s, *marketed* Canadian gas production has more than doubled, reaching 6.2 Tcf (17.0 Bcf/d) in 2000, a quarter (24%) of North American gas production. When North American production peaked in 1973, Canada accounted for about 10% of North American gas production. If U.S. gas demand is to grow to 30 Tcf and beyond, Canadian gas production will play a critical role in supplying that increased demand. However, growth in Canadian gas production has slowed since the mid-1990s. Between 1986 and 1996, *marketed* Canadian gas production grew 290 Bcf/year (800 MMcf/d). Since 1996, annual growth has slowed to 150 Bcf/year (410 MMcf/d).

Sedimentary basins *do not* underlie most of the Canadian surface area (onshore and offshore). Figure 4.1 illustrates the areal extent of sedimentary basins in Canada. Almost all (99%) of Canadian gas production has come from the Western Canada Sedimentary Basin (WCSB), which underlies most of Alberta, and parts of British Columbia, Saskatchewan, Manitoba, and adjacent regions in the Yukon and Northwest Territories. The remaining production has come from Ontario and recently from Offshore Nova Scotia.

Figure 4.1
Sedimentary Basins in Canada

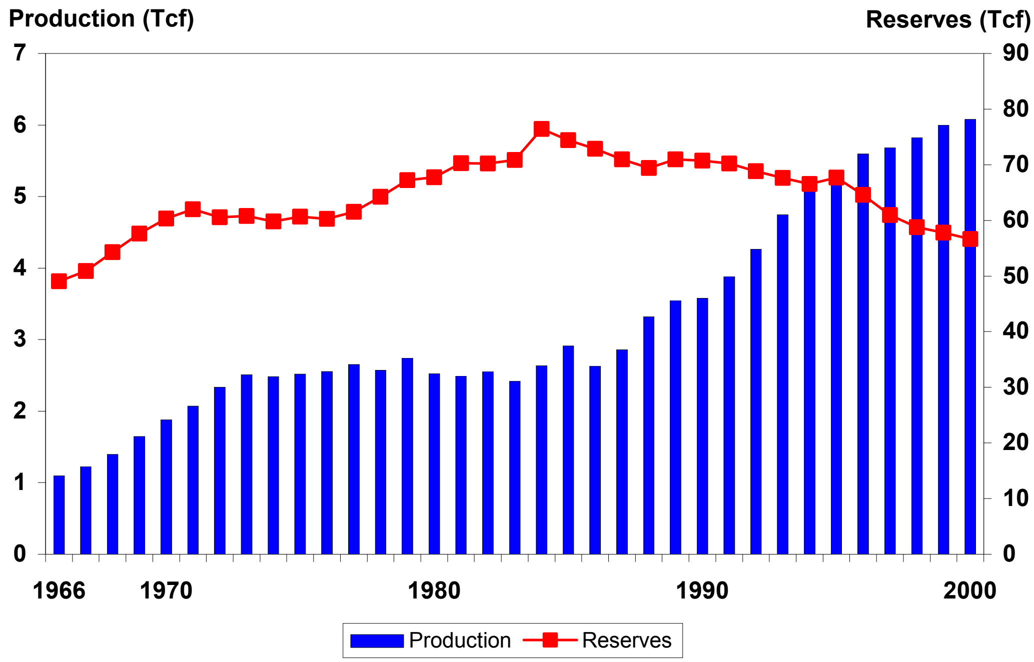


This chapter will review long-term trends in Canadian gas production, reserves, and drilling activity. Production and reserves data are discussed on a marketed (wet) basis before extraction of gas liquids by gas plants *outside* producing leases. Reserves data are discussed on an established (proved plus risked probable), which is favored by Canadian regulatory bodies (e.g. National Energy Board), and a proved only basis.

Western Canada Sedimentary Basins (WCSB)

Figure 4.2 presents the trends in WCSB gas production and established gas reserves since 1966. WCSB gas production more than doubled between 1966 and 1973. Between 1973 and 1984, however, production plateaued, averaging 2.55 $\pm$ 0.09 Tcf/yr. During this period of stability, Alberta gas production grew, offsetting a decline in British Columbia gas production. By 1984, 88% of WCSB gas production came from Alberta, compared to 78% in 1973.

Figure 4.2
Western Canada Gas Production
vs *Established* Reserves



Established WCSB gas reserves continued to grow after 1973, peaking in 1984 at 76.4 Tcf. In 1984, the reserve-to-production (RP) ratio was 27.7. In 1984, 88% of WCSB gas reserves were in Alberta, and 11% in BC/Territories.

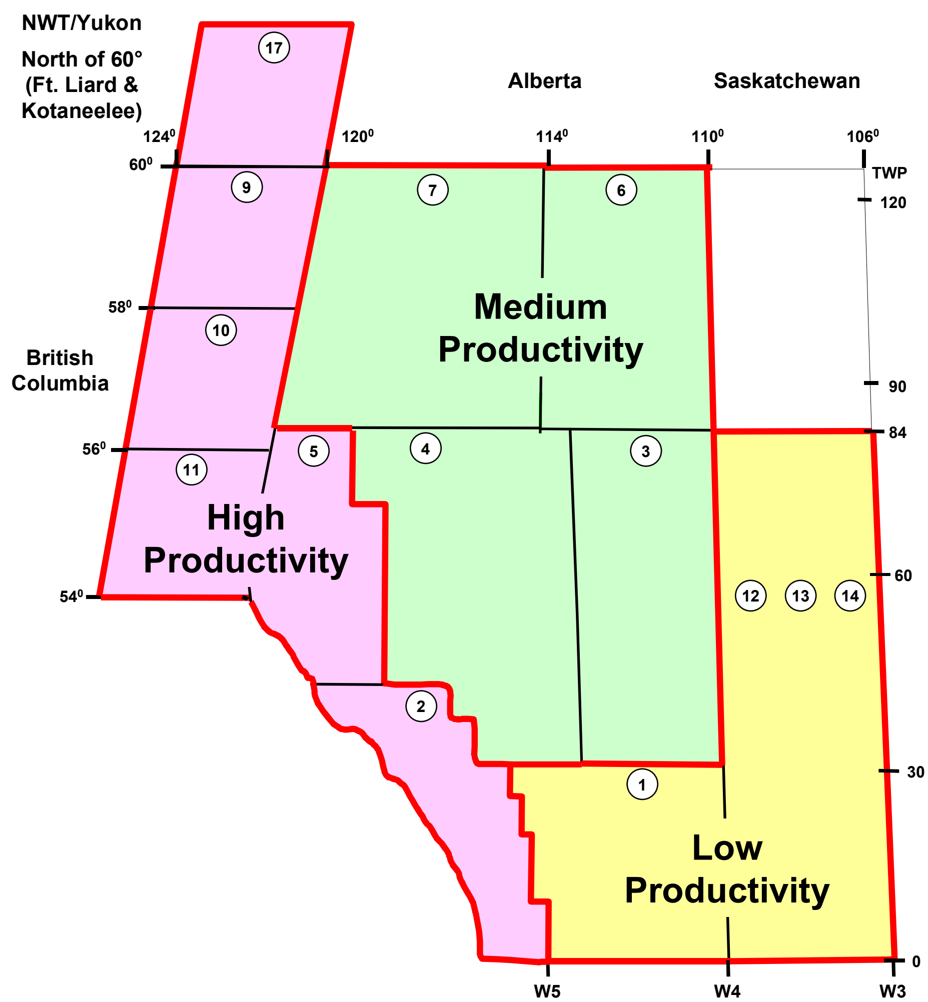
In 1986, as part of market deregulation, the Canadian government removed regulatory requirements for a 25-year *established* reserves (proved plus risked recovery from contiguous inferred reserves) to production (RP) ratio for approval to be granted to export Canadian gas to the United States. With the removal of the reserves requirement, WCSB gas production surged. By 1996, it had more than doubled, growing 300 Bcf (810 MMcf/d) per year to reach 5.6 Tcf (15.3 Bcf/d). Established gas reserves, however, declined. By 1996, reserves were 64.6 Tcf, resulting in an RP ratio of 10.5.

Although WCSB gas drilling activity has more than doubled after 1996, growth in production slowed, averaging 120 Bcf (330 MMcf/d) per year since 1996. Growth picked up modestly in 2001 with the onset of gas production from the large Ladyfern discovery on the BC/Alberta border.

However, established reserves continued to decline, falling to 57 Tcf in 2000, their lowest level since 1969. In 2000, the RP ratio was 9.7. The decline in the *established* RP ratio has caused concern about future prospects for increased Western Canada gas production.

The perception of limited prospects for increased Western Canada gas production was strengthened because the growth in gas production slowed as gas activity surged. However, a major share of the 1996-2000 drilling surge was in the relatively shallow, low-productivity areas of Western Canada, Southeast Alberta and Saskatchewan (Figure 4.3). Current production per well in this area averages less than 100 Mcf/d, compared to about 300 Mcf/d in Western Canada as a whole.

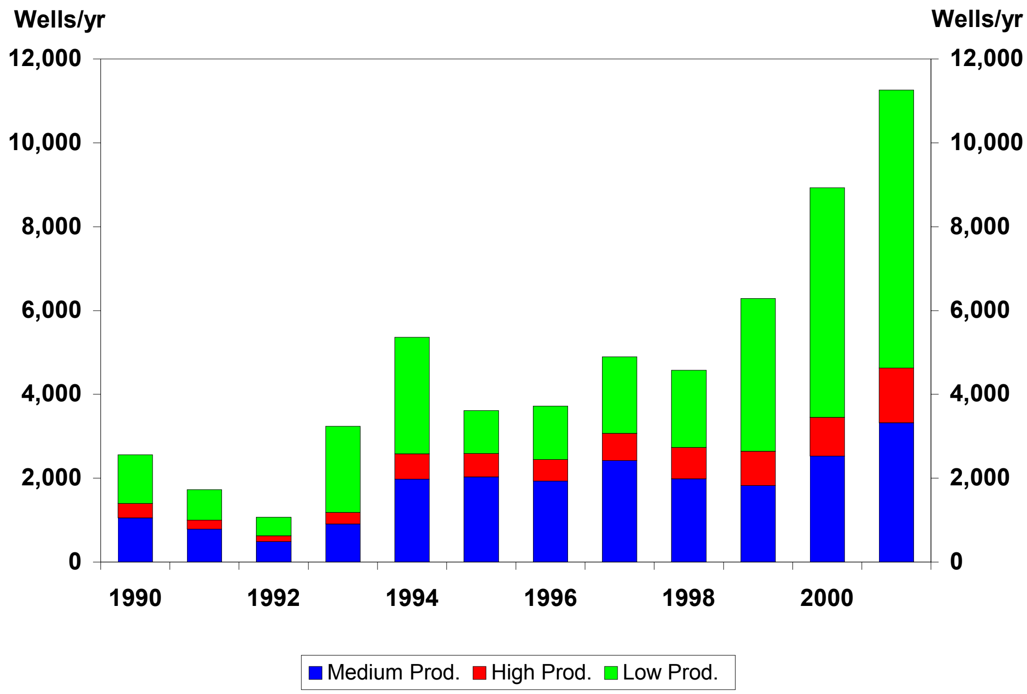
Figure 4.3
Western Canada Productivity Regions
Ziff-Hankel Regions



The high-productivity area is comprised of the Alberta Foothills and BC/Territories. Average production per gas well in this area ranges from 750 to 2,000 MMcf/d. The medium productivity area is comprised of the rest of the Alberta Plains area, where average production per well is in the 250-600 Mcf/d range. The medium productivity area provides almost half of Western Canada gas production.

Figure 4.4 allocates gas drilling activity in Western Canada to these regions. In 2001, more than 11,000 new gas completions were made, triple the number in 1996. Almost three fourths of this growth was in the low productivity area, which provides less than 20% of Western Canada gas well production. In 2001, 59% of new gas wells were in the low productivity region, compared to 34% in 1996.

Figure 4.4
Western Canada New Gas Wells



Gas drilling activity in the medium productivity area showed no sustained growth through 2000. As a result, only 28% of new gas well completions in 2000 were in this area, compared with more than half in 1995-96. Because of the lack of sustained growth in new gas well completions between 1995 and 2000, gas well production in this area has not grown since 1996. Between 1990 and 1996, it provided more than half of the growth in Western Canada gas well production. While activity in the medium productivity region surged in 2001 to more than 3,200 new completions, this growth is not likely to noticeably affect gas well production until 2002. Unless activity in the medium productivity area can be sustained at 3,000 wells or more, *long-term* growth in Western Canada gas production is unlikely to exceed its 1996-2000 range.

New gas completions in the high productivity area have doubled since 1997, and this area has provided most of the growth in Western Canada gas well production since 1996. The surge in new completions during 2001, which includes a potentially significant discovery Northeast British Columbia (Greater Sierra), and the development of the Ladyfern discovery indicate that this area could continue to dominate growth in Western Canada gas well production in the near term.

If the Western Canada coalbed methane resource proves productive (as some pilot projects suggest), the recoverable resource could be comparable to the remaining conventional resource. In most U.S. basins, coalbed methane production averages about 100 Mcf/d per well. While this is considered low productivity, this average production per well exceeds average production per well for Southeast Alberta and Southwest Saskatchewan, which account for almost 20% of the gas well production and about two thirds of the producing gas wells in Western Canada. Therefore, coalbed methane gas wells might prove to be as productive as most conventional wells in Western Canada.

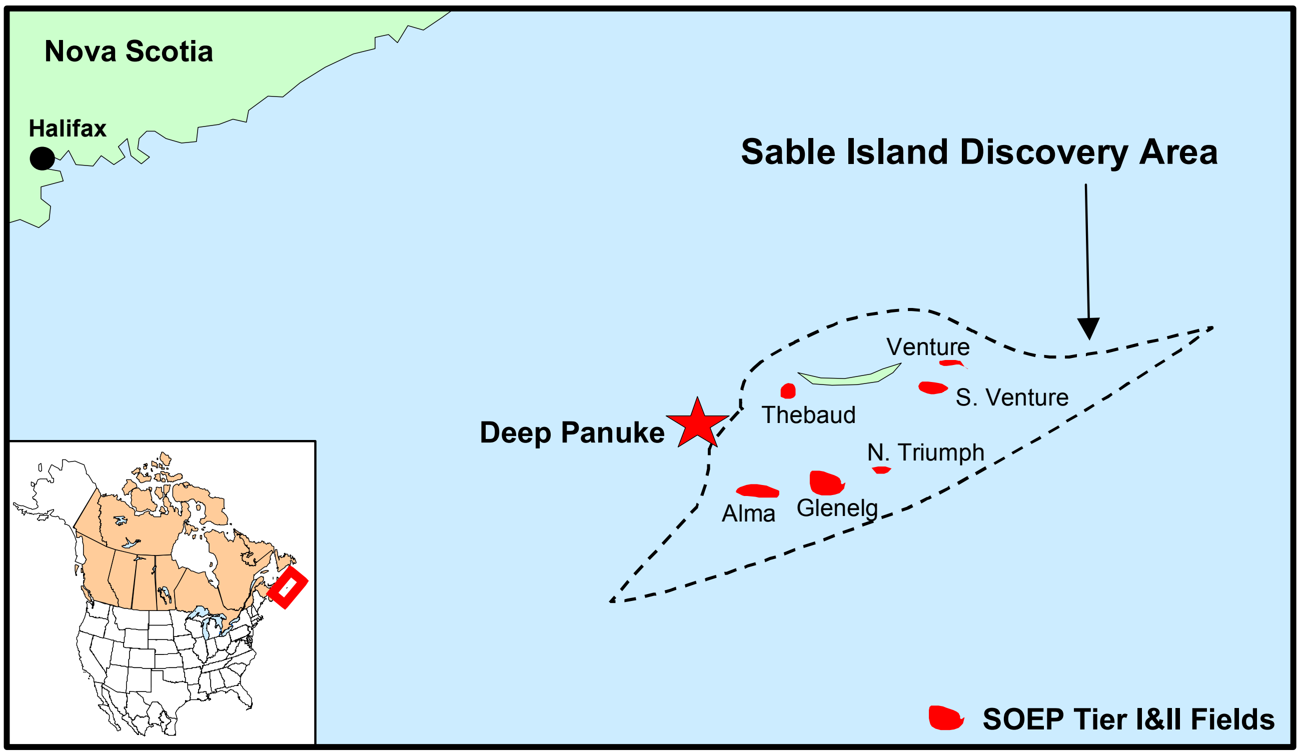
Eastern Canada

Eastern Canada gas production comes from Ontario, Offshore Nova Scotia, and Offshore Newfoundland. In 2000, gas production in Eastern Canada was 240 Bcf, of which 140 Bcf was *marketed*. Data suggest that Eastern Canada gas production exceeded 300 Bcf in 2001, of which 200 Bcf was marketed. The unmarketed Eastern Canada gas production, which is from offshore Newfoundland, is re-injected into the Hibernia field to improve its oil recovery. Onshore activity has begun in New Brunswick, Prince Edward Island, and Nova Scotia.

Offshore Nova Scotia

Almost eight Tcf of gas discoveries have been made in Offshore Nova Scotia. More than three fourths of these reserves are in seven fields, which are either producing or should be producing by 2005. Figure 4.5 shows these seven discoveries associated with the Tier I and Tier II Sable Island developments, plus the deep Panuke discovery by PanCanadian.

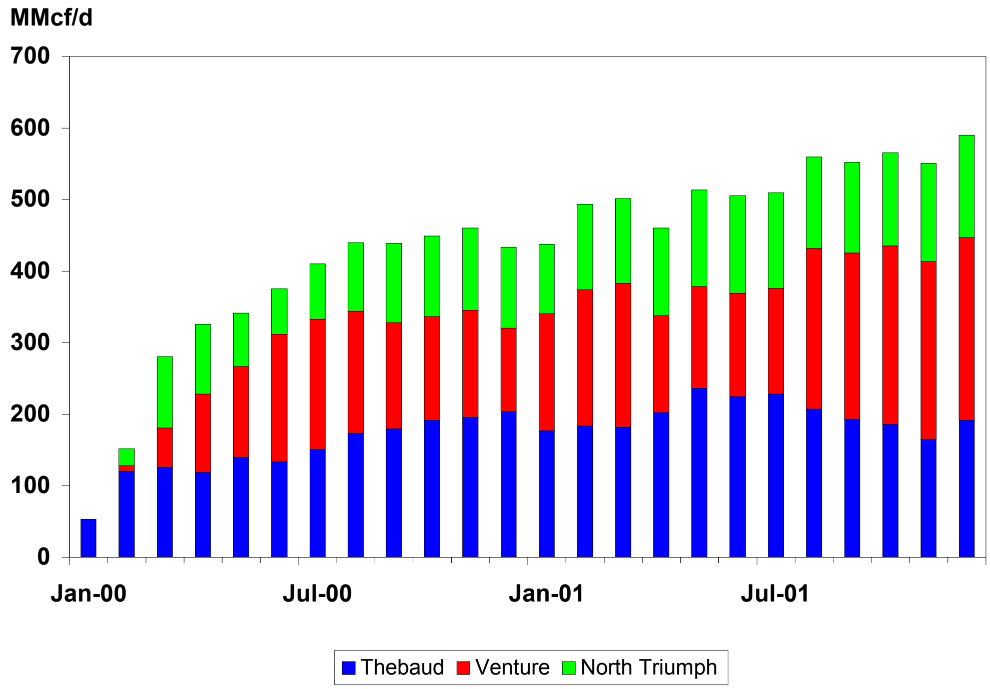
Figure 4.5
Nova Scotia Offshore Discoveries



Marketed gas production from Offshore Nova Scotia began in January 2000 with production from the Thebaud field. Production from the Venture and North Triumph fields began in February. Reserves for these three fields are estimated to be 2.8 Tcf, with the Venture field containing more than half. Development activity is beginning for the Alma field, and production is expected to begin in 2003. Alma is comparable in size to North Triumph, which is producing about 140 MMcf/d.

Figure 4.6 allocates Sable Island gas production to the three producing fields. Gas production grew steadily through September 2000, and has since moved through three plateaus of steadily increasing gas production. From September to January, Sable Island gas production averaged 440 MMcf/d from ten producing wells. From February to July, production averaged almost 500 MMcf/d, but with only nine wells usually producing. With eleven gas wells producing, Sable Island production increased to almost 550 MMcf/d between August and November. Production in December 2001 grew to almost 590 MMcf/d, and a new well began production. It would not be surprising for Sable Island gas production to exceed 600 MMcf/d in 2002.

Figure 4.6
Sable Island Raw Gas Production



Prospects for continued growth in Sable Island production appear good. The RP ratio for the three producing fields was 13 at year-end 2001, and 22 for the Venture field. While the RP ratio for North Triumph is only 6.5, production per well and total production in this field grew in 2001, suggesting that reserves in this field may be revised upwards.

On the other hand, water production increased substantially in 2001, and Shell Oil recently revised downward its share of Sable Island gas reserves by 300 Bcf. The growing water production raises a question of whether Alma production will add to Sable Island production or offset production declines from currently producing fields.

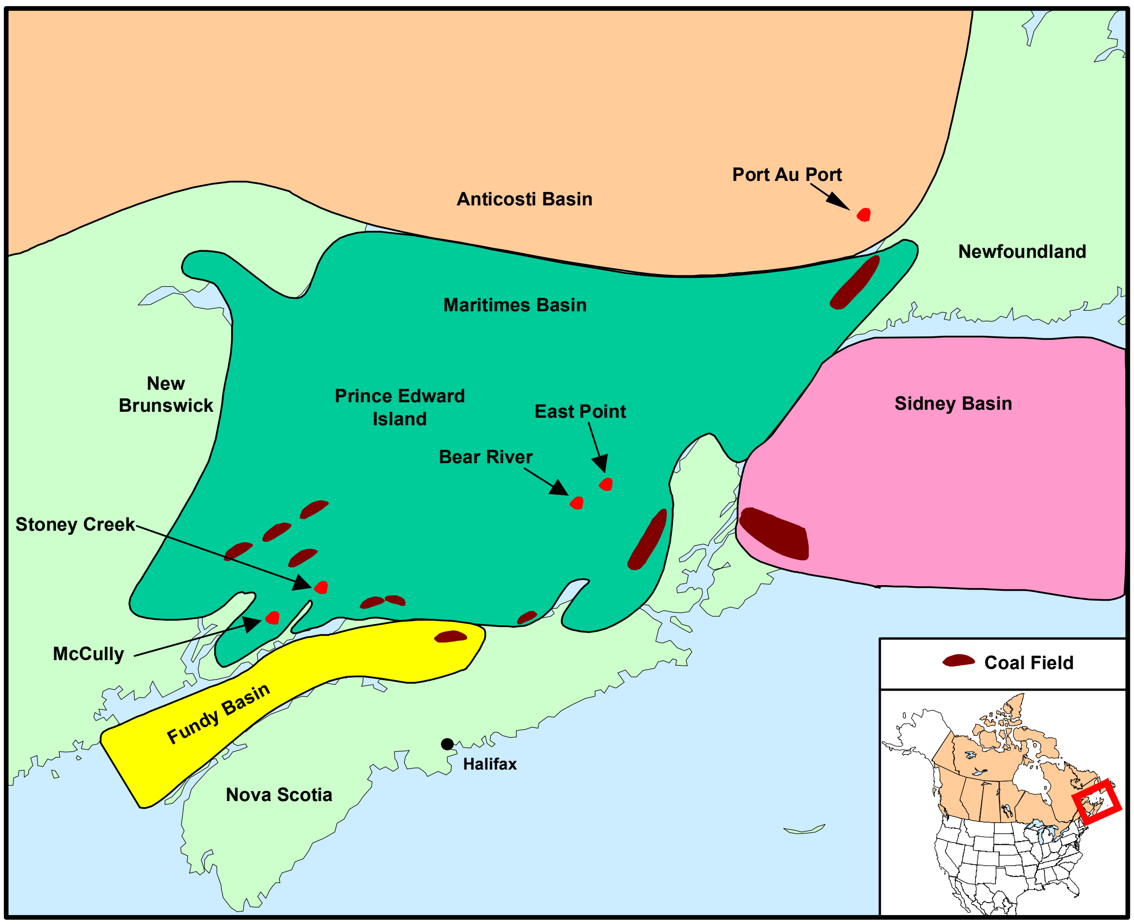
Estimates of Panuke's size exceed one Tcf. PanCanadian proposes to bring Panuke gas ashore using a 400 MMcf/d pipeline that could be expanded to 650 MMcf/d. For a 25-year project, this implies that Panuke recovery could exceed three Tcf. Production is planned to begin in late 2004 or early 2005. The Maritimes and Northeast Pipeline is expanding to accommodate this production.

Prospects for continued discoveries in Offshore Nova Scotia appear good. The significant sizes of the initial discoveries suggest a very large resource potential. The very large acreage positions that industry has recently taken on both the Shelf and in the Deepwater indicate that industry is preparing to aggressively follow up on the initial successes in Offshore Nova Scotia.

"Onshore" Eastern Canada

"Onshore" Eastern Canada includes sediments under the Great Lakes and St. Lawrence. Currently, about 15 Bcf of gas is produced in Ontario. While there is no onshore gas production in the Maritime Provinces, some promising discoveries have been made. Figure 4.7 indicates some Eastern Canada areas where discoveries have been made and potential coalbed methane areas.

Figure 4.7
Onshore Maritimes and Gulf of St. Lawrence



Corridor Resources has drilled three successful wells in New Brunswick, and production should begin in 2002. The McCully discovery was recently estimated to have about 300 Bcf of gas-in-place, which implies a substantial field. A large U.S. gas producer, EOG Resources, has farmed-in to the area. If McCully meets initial estimates, noticeable onshore Maritimes gas production might develop, because a field of McCully's size is generally not an orphan.

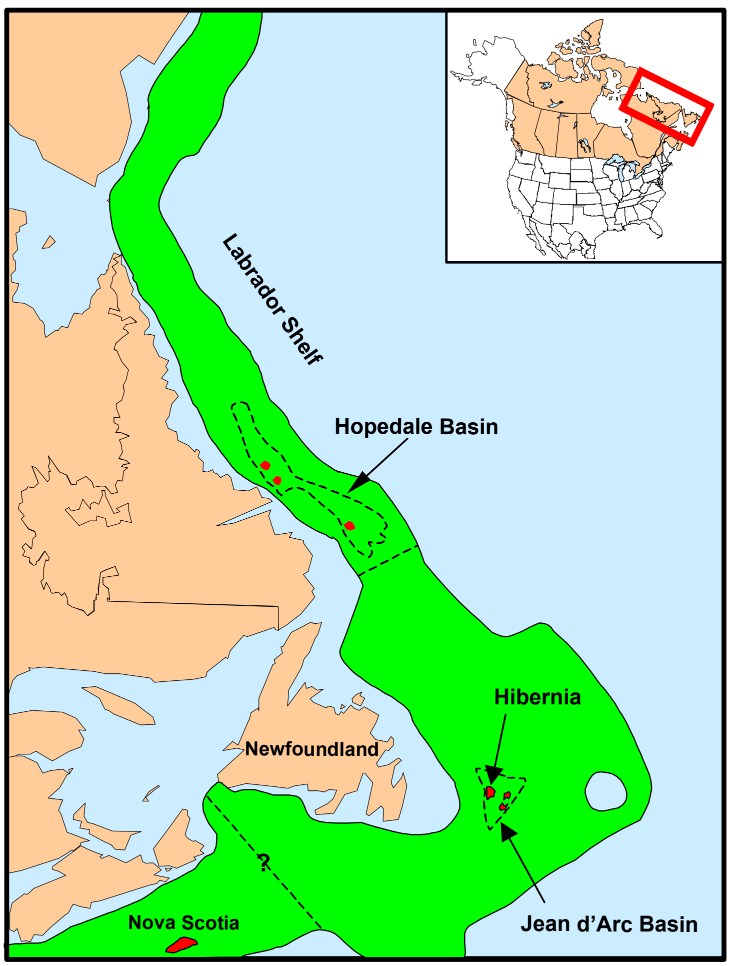
Industry activity has also occurred in onshore Prince Edward Island and Nova Scotia. A recent well in Prince Edward Island (Bear River) had promising gas shows. While the sands appear prospective, they also appear tight, thus requiring fracturing to be economic. Interest in coalbed methane resources has developed in Nova Scotia, with PanCanadian acquiring a significant lease position. Finally, a "discovery" was made in onshore Southwest Newfoundland, but subsequent step-outs were dry. A "discovery" was also made in the Gulf of St. Lawrence, but it was uneconomic.

While production should develop in the onshore Maritimes, results to date suggest it will be on the order of tens of Bcf. Thus, it might be significant for the local markets, but unlikely to play a role in markets outside the area.

Offshore Newfoundland-Labrador

While extensive sediment volumes are in the offshore Atlantic areas of Newfoundland-Labrador, significant discoveries have only been made in the Jean d'Arc and Hopedale basins. Based on discoveries to date, Jean d'Arc is oil-prone, and the Hopedale is a pure gas play. Figure 4.8 indicates these areas and their principal discoveries.

Figure 4.8
Newfoundland and Labrador



The 18 significant discoveries made on the Grand Banks have an estimated recovery (Canada-Newfoundland Offshore Petroleum Board [C-NOPB]) of 2.1 billion barrels of oil and 5.7 Tcf of gas. More than 90% of the oil and 80% of the gas are in four fields: Hibernia, Terra Nova, White Rose, and Hebron/Ben Nevis. Hibernia is the largest field, with an estimated recovery exceeding one billion BOE. Production from Hibernia began in late 1997, and production from Terra Nova has just begun. Proposals have been made to develop production from White Rose and Hebron/Ben Nevis.

In 2001, production was 54 million barrels (150,000 Bbl/d), and gas production was 92 Bcf (250 MMcf/d), almost half of Sable Island gas production. However, almost all gas production is re-injected to improve recovery of oil-in-place. Because of the large start-up costs associated with delivering gas from Hibernia to distant markets and the economic value of continued re-injection, it will probably be on the order of a decade before Hibernia gas production finds its way to market.

Terra Nova begins production in 2002, possibly bringing Grand Banks production to 265,000 Bbl/d and associated gas production to more than 300 MMcf/d by the end of the year. If White Rose and Hebron/Ben Nevis are developed, C-NOPB expects that oil production could reach 400,000 Bbl/d by 2007. This implies gas production could approach one Bcf/d (based on gas-to-oil ratios of current C-NOPB reserves estimates). This might be a sufficient to consider building a gas transportation system to deliver Grand Banks gas to North American gas markets. The critical issue is the economic value of delivering gas to market versus continued re-injection to improve oil recovery.

The Labrador Shelf has had five significant discoveries beginning in 1974 with an ultimate recovery of 4.2 Tcf, but no drilling activity since 1983. No oil has been discovered on the Labrador Shelf. The largest field is North Bjarni with a recovery of 2.2 Tcf, comparable in size to Terra Nova on a BOE basis. However, its remote location indicates that gas deliveries from the Labrador Shelf to North American gas markets would probably follow deliveries of gas from Offshore Newfoundland by a decade or more, and only if limited new discoveries were made in offshore Nova Scotia and Newfoundland *and* substantial new discoveries were made on the Labrador Shelf. There is no activity on the Labrador Shelf at present.

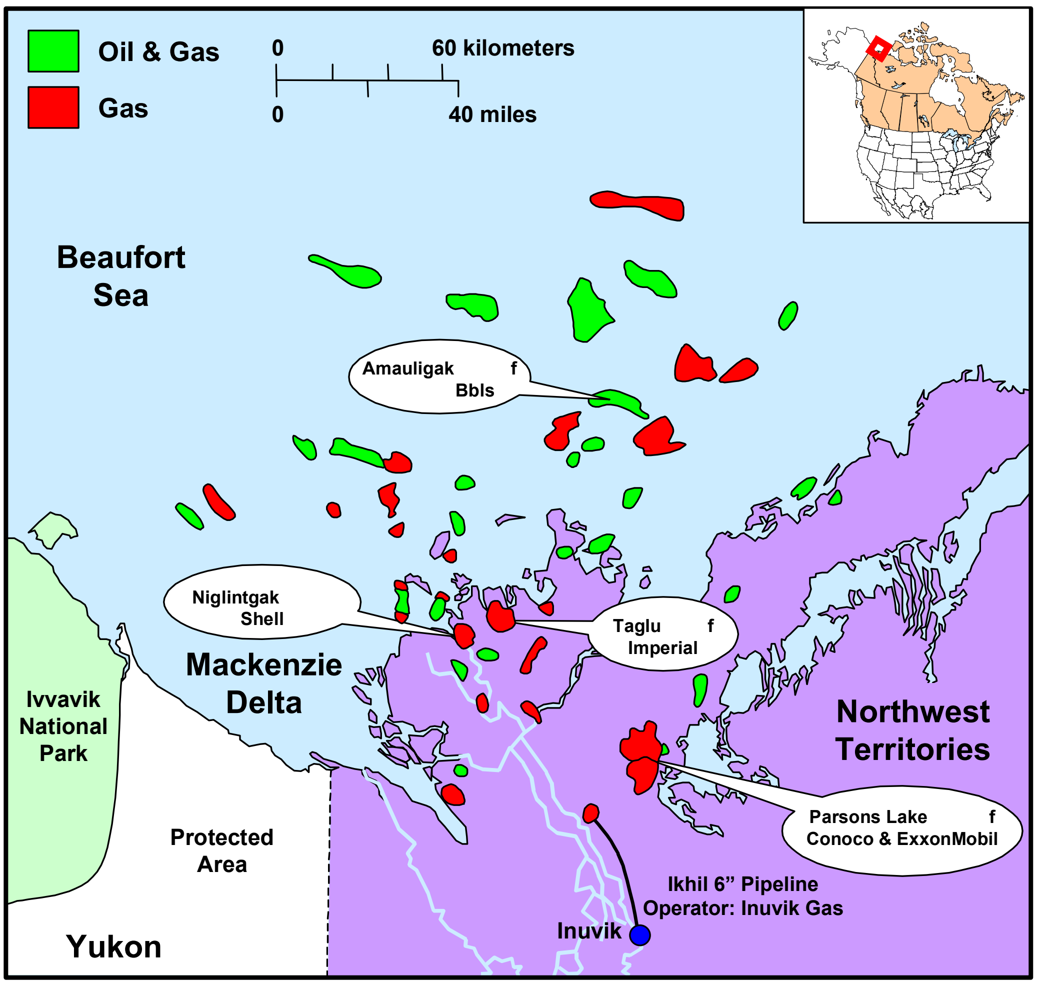
Northern Basins

While extensive sediments extend North from the WCSB, limited discoveries have been made between the WCSB and the Arctic Circle. North of the Arctic Circle, however, substantial discoveries have been made.

Exploration in the Mackenzie Delta/Beaufort Sea area began in the early 1970s. In 1974, the first reserves were booked. Subsequent activity resulted in established reserves reaching 10.5 Tcf in 1989. In 1994, however, following a sustained period of low prices and surplus gas availability in the lower-48 and WCSB, these reserves were debooked as uneconomic. Today, interest has revived in bringing this gas to market within the decade.

Figure 4.9 shows the discoveries that have been made to date. The National Energy Board of Canada (NEB) reports 27 discoveries (18 with gas) in the Mackenzie Delta and 26 discoveries (22 with gas) in the Beaufort Sea. The NEB mean estimates of marketable gas reserves for these discoveries are 4.9 Tcf in the Mackenzie Delta and 4.0 Tcf in the Beaufort Sea. Industry estimates for some fields are much higher. The NEB estimates that the *undiscovered resource potential* in the area is *55 Tcf*.

Figure 4.9
Mackenzie/Beaufort Sea Discoveries



The two largest gas accumulations in the Mackenzie Delta are Taglu (NEB estimate of 2.1 Tcf and industry estimate of 3 Tcf) and Parsons (NEB estimate of 1.3 Tcf and industry estimate of 1.8 Tcf). In the Beaufort Sea, the two largest gas accumulations are Amauligak (mean estimated recovery of 1.4 Tcf) and Issungnak (mean estimated recovery of 1.1 Tcf). NEB characterizes both Beaufort Sea gas accumulations as oil fields. The largest gas *only* discovery in the Beaufort Sea is Kenalooak (estimated mean recovery 0.2 Bcf). Thus, significant gas production from the Beaufort Sea discoveries is *not* likely until well after gas deliveries begin from the Mackenzie Delta *or* after oil production begins. Given the sizes of Beaufort Sea oil fields (Amauligak, the largest, has less than 250 million barrels), *significant* oil and gas production in the Beaufort Sea will probably lag Mackenzie Delta gas production by many years, unless new, larger discoveries are made.

Gas deliveries from the Mackenzie Delta-Beaufort Sea area to the North American pipeline grid will probably not begin until late this decade, although gas production (1 MMcf/d) has begun in the Mackenzie Delta to serve the local market. Proposed capacity for gas deliveries from the Mackenzie Delta is 1-1.5 Bcf per day. Because reserves in the Mackenzie Delta discoveries cannot support a pipeline of one Bcf per day for 25 years, current plans to deliver gas from the Mackenzie Delta area would rely on further discoveries.

Renewed exploration interest in the Mackenzie Delta has led to bid rounds in 1999 and 2000, and most of the prospective onshore acreage has now been leased. Petro-Canada, in partnership with Devon, drilled the first well in this exploration round. Given resource prospects, discoveries to support a 1-2 Bcf per day pipeline could be made to support the beginning of such deliveries within the decade.

The Arctic Island discoveries are about 900 miles from the Mackenzie Delta. While estimated reserves (16 Tcf) for the Arctic Islands discoveries are almost double estimated reserves for the Mackenzie Delta-Beaufort Sea, their greater distance to market suggests that Arctic Islands production is unlikely to begin until after gas production in North Alaska and the Mackenzie Delta-Beaufort Sea can no longer grow.

Final Observations

Canadian gas production can grow in the future, but that growth is likely to increasingly rely on production outside Western Canada *or* a large development of coalbed methane production in Western Canada. Growth in Western Canada *conventional* gas production is uncertain and unlikely to exceed 100 Bcf/year. A critical uncertainty is whether the lack of growth in the medium productivity area of Western Canada indicates long-term prospects or reflects the lack of sustained growth in new gas completions between 1994 and 2000.

Coalbed methane production could become substantial. The in-place resource could make Western Canada one of the largest, if not largest coalbed methane area in North America. Based on experience in the United States, a coalbed methane production peaking at 3 Bcf/d would not be surprising. However, coalbed methane activity is still in the pilot stage, and significant production would probably depend heavily on technology advances.

Activity outside of Western Canada should provide substantial, additional production. This growth, however, would depend on large expansions of the “ultimate” resource base and development of “green field” pipeline projects to connect these mostly “remote” areas to North American gas markets.

CHAPTER 5

GAS SUPPLY PROSPECTS

GAS SUPPLY PROSPECTS

Introduction

Concern has developed about the extent to which North American gas supply can grow without putting severe upward pressures on gas prices. The price surge of Winter 2000-2001, when Henry Hub gas prices tested $10/MMBtu, suggested that significant growth in gas supply may not be possible without prices that sharply reduce the economic attraction of gas use. While gas prices have fallen sharply since then, production growth also seems to be tailing off, suggesting that the production growth in 2001 may be short-lived.

From a longer-term perspective, the picture is different. "Ultimate" gas resource estimates have grown more than industry activity has "depleted" them for about 20 years, suggesting that depletion effects should not be very visible in industry results. Overall reported reserve additions per new gas well have been stable to growing in the lower-48 as a whole. While some parts of the lower-48 and Western Canada show declining yields, the overall picture appears strong from a physical resource perspective, particularly if new supply regions are developed. And yet gas prices appear under severe upward pressure.

This chapter will discuss prospects for lower-48 and Canadian gas production through 2020 based on the results of the previous chapters. Two production scenarios are developed in this chapter.

- The **High Production Scenario** is based on expectations that "ultimate" gas resource estimates can continue to expand ahead of resource depletion, as they generally have for the last 20 years. In this scenario, gas yields show little decline, and demand for increased gas drilling activity tracks closely with increased gas production *after* the gas reserves inventory is rebuilt. As a result, long-term, upward pressures on gas prices are modest in this scenario.

- A **Low Production Scenario** is based on expectations that expansions of the "ultimate" resource estimates will slow in the next 20 years. In this scenario, gas yields would decline noticeably, and the demand for increased gas drilling activity would outstrip the growth in gas production, even after the reserves inventory is rebuilt. As a result, long-term upward pressures on gas prices are noticeable in this scenario.

The production scenarios developed should not be seen as forecasts but rather as indicators of the range over which lower-48 and Canadian production might be expected to develop.

Upstream Economics

While the principal, long-term factor affecting upstream economics are yields of industry activity and gas demand, other supply factors can also have significant effects, sometimes for the long term. Two such factors are the *acceleration of decline rates* and *declines in the RP ratios*. These two factors have placed upward pressures on gas prices and may affect the long-term prospects for increased gas production.

Decline Rates

Through the mid-1990s, industry investment reflected a steady-state world with *nominal,* annual declines of Gulf of Mexico wells in the 15-20% range and onshore wells in the 10-15% range. In the late 1990s, technology advances allowed industry to bring more of a well's recovery forward in time, or "blow and go," enhancing the net present (economic) value of the reserves. Declines in deliverability from producing gas wells accelerated in most areas of North America, rising to 35% or more in the Gulf of Mexico and 25% or more in onshore areas. As a result, new gas wells were needed not just to replace reserves but to offset the acceleration in gas deliverability declines from producing gas wells. The need for incremental wells to offset accelerated declines placed upward pressure on gas prices to help finance the additional investment.

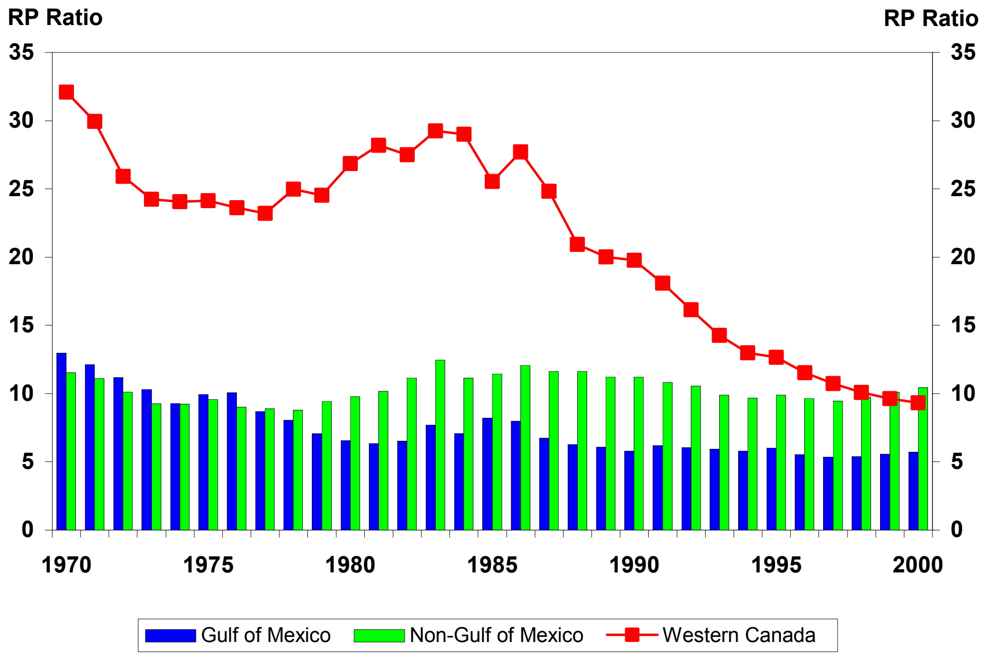
At some point, decline rates should reach a new steady state. When this steady state is reached, the need *to continue to increase* the number of new gas wells will end, but it will probably not reduce the number of new gas wells needed. While upward pressures on gas prices due to accelerating decline rates will end, prices will not return to their mid-1990s levels when decline rates were lower.

RP Ratios

RP ratios are an indication of supply inventory. A decline in the RP ratio is not in itself an indication of imminent or even necessarily developing problems for supply. In fact, because a declining RP ratio can increase the net present value of an investment, it may reduce the price needed to make a target rate of return. On the other hand, a low RP ratio may create a situation in which mere replacement of production may not be sufficient to maintain current production levels for a sustained period, particularly when decline rates are accelerating. In these areas, industry activity may have to be targeted at adding more reserves than are produced to develop a high probability that production can be maintained over the long term.

Figure 5.1 presents trends in gas RP ratios for proved reserves in the Gulf of Mexico and the rest of the lower-48 (almost all onshore) and for established reserves in Western Canada. The figure shows very large declines in RP ratios for Canada and the Gulf of Mexico. The *trend* in the RP ratio for the *rest of the lower-48*, however, is quite different. While it has varied over the last 30 years, it has shown *little or no long-term decline*.

Figure 5.1
North American RP Ratios



A review of RP trends in light of production trends indicates that *RP ratios* for *onshore areas* probably should be *about ten before prospects for sustained growth* (more than one year) *in production are solid*. As a result, sustained production growth prospects in *Western Canada* with an RP ratio of 9 are weak, but production prospects for the "onshore" lower-48 with an RP ratio of 10.5 appear good. In the *Gulf of Mexico*, significant growth in gas well production has occurred at an RP ratio as low as seven. When the RP ratio approaches five, industry is probably running as fast as in can to stay in place.

Because of low RP ratios, replacement of gas production by industry activity in Western Canada or the Gulf of Mexico is *not* likely to lead to much, if any sustained growth in gas production. If gas production is to grow *and* be sustained, reserve additions in these two areas must exceed simple reserves replacement *and* increase the RP ratio. In Western Canada, reserves would probably have to exceed 60 Tcf for significant, sustained growth to occur. In these areas and some parts of the onshore lower-48, the investments to increase production would put upward pressures on gas prices to help finance the additional activity. In the lower-48, however, the RP ratio can support some sustainable growth in gas well production without investments outrunning revenues and putting upward pressures on gas prices.

Implications

The upward pressures on gas prices due to accelerating decline rates may be near their end. While low RP ratios do not preclude gas production growth in mature areas, such as the Gulf Coast, Western Canada, and the Gulf of Mexico Shelf, they do reduce the likelihood of *sustained and substantial annual* growths without severe upward pressures on gas prices. If growth occurs in low RP producing areas without substantial, upward pressures on gas prices, it will have to be modest and steady. Only in the Deepwater Gulf of Mexico (really a frontier region) and the Rocky Mountain region (RP ratio of 14.5) can large, annual growths be sustained. Most opportunities for *substantial, rapid growth* will have to rely on frontier areas or resources in the lower-48 or Canada.

Production Outlook

Although gas production can grow in most producing areas of North America, current RP ratios and extensive development to date suggest that this growth is likely to be modest, averaging on the order of 100 Bcf per year. In frontier areas, such as the Deepwater Gulf of Mexico, Sable Island, and the offshore lower-48 areas under moratorium, growths could be significant.

Lower-48

Table 5.1 summarizes lower-48 gas production prospects under the two scenarios. The two scenarios are presented as a range.

Table 5.1
Lower-48 Marketed Gas Production (Tcf)

Region	1980	2000	2005	2010	2015	2020
Gulf of Mexico	5.6	5.3	5.8	6.1-6.2	6.1-6.6	5.8-6.9
Gulf Coast Onshore	4.7	4.0	4.2-4.3	4.2-4.5	4.1-4.5	3.8-4.4
Interior Southwest	6.7	5.8	5.5-5.7	5.2-5.5	4.9-5.2	4.4-4.8
Rocky Mountains	1.2	3.3	3.8-4.0	4.1-4.5	4.2-4.8	4.2-4.9
Other Region	1.0	1.3	1.4-1.5	1.4-1.6	1.5-1.7	1.5-1.8
Producing Lower-48	19.3	19.7	20.8-21.3	21.0-22.2	20.8-22.8	19.7-22.8
Frontier Regions				0-0.8	0-1.3	0-1.9
Total Lower-48	19.3	19.7	20.8-21.3	21.0-22.8	20.8-23.6	19.7-24.0

Lower-48 gas production grows in both scenarios in the near-term, but that growth is only long-term in the **High Production Scenario**. However, without production from areas subject to moratorium, growth in lower-48 gas production would be largely over by 2015 in the **High Production Scenario**. In the **Low Production Scenario**, production falls off after 2010. By 2020, production has fallen back to its 2000 level. Frontier regions do not produce in the **Low Production Scenario**.

In both scenarios, the *major growth areas* are the *Gulf of Mexico* and the *Rocky Mountains*. In both areas as well as the Other Region, production grows during the entire period in the **High Production Scenario**, but it tails off in the Gulf of Mexico after 2015 in the **Low Production Scenario**.

The region with the least prospects for growth is the Interior Southwest. Although gas production in North Texas/Louisiana is likely to grow, that growth will probably only offset by declines in other parts of the region, particularly the Midcontinent.

The Onshore Gulf shows some growth through much of the projection period in both scenarios, but that growth is modest and probably confined to South Texas. South Louisiana is something of a wild card. Much of its deeper sediments remain to be explored, but development success rates are poor in the region, less than 70% compared to 85-90% and better in other areas of the lower-48. If technology advances can improve success rates in Southern Louisiana, production might show some growth instead of a long-term decline.

The steady growth in the Other Region indicates that it has some good prospects. Industry activity is moving into deeper sediments in California, and Canadian producers are moving South of the Border into the lower-48 part of the Williston Basin. Appalachian shale is a wild card. If technology advances sufficiently and producers can accommodate the risks, Appalachian shale production might take off and raise production beyond that expected in the **High Production Scenario**.

The cumulative discoveries between 2000 and 2020 in the two scenarios are 400-500 Tcf, of which about 125 Tcf are in the Gulf of Mexico. The possible growth expected in the “ultimate” lower-48 resource for the producing areas over the next 20 years is 300-600 Tcf, of which 100-200 Tcf is in the producing part of the Gulf of Mexico. In the **High Production Scenario**, gas resource should probably grow at or ahead of the pace of reserve depletion. As a result, yields should remain reasonably stable, allowing gas production to develop with at most modest upward pressures on gas prices. In the **Low Production Scenario**, resource growth does *not* keep pace with resource depletion, thus putting *upward pressures on gas prices*.

Canada

Table 5.2 summarizes Canadian gas production prospects under the two scenarios. The two scenarios are presented as a range.

Table 5.2
Canadian Marketed Gas Production (Tcf)

Region	1980	2000	2005	2010	2015	2020
Western Canada	2.5	6.1	6.6	6.6-7.0	6.7-7.6	6.7-8.0
Nova Scotia		0.1	0.4	0.6-0.8	0.8-1.1	1.1-1.5
Newfoundland				0-0.2	0.4-0.6	0.4-0.8
Mackenzie Delta				0.4	0.4-0.6	0.4-0.7
Total Canada	2.5	6.2	6.9	7.5-8.2	8.5-9.8	8.5-11.0

Canadian gas production grows substantially in both scenarios. In the **High Production Scenario**, production almost doubles, growing from 6.2 Tcf (17.0 Bcf/d) to 11.0 Tcf (30.1 Bcf/d). In this scenario, Canadian gas production would be almost half of lower-48 gas production. Growth occurs in all areas, but most noticeably *outside Western Canada*. By 2020, more than one fourth of Canadian gas production could come from outside Western Canada.

Western Canada gas production in the **High Production Scenario** grows about one third, with most of this growth due to coalbed methane. Without substantial success in coalbed methane, Western Canada gas production is likely near its peak today.

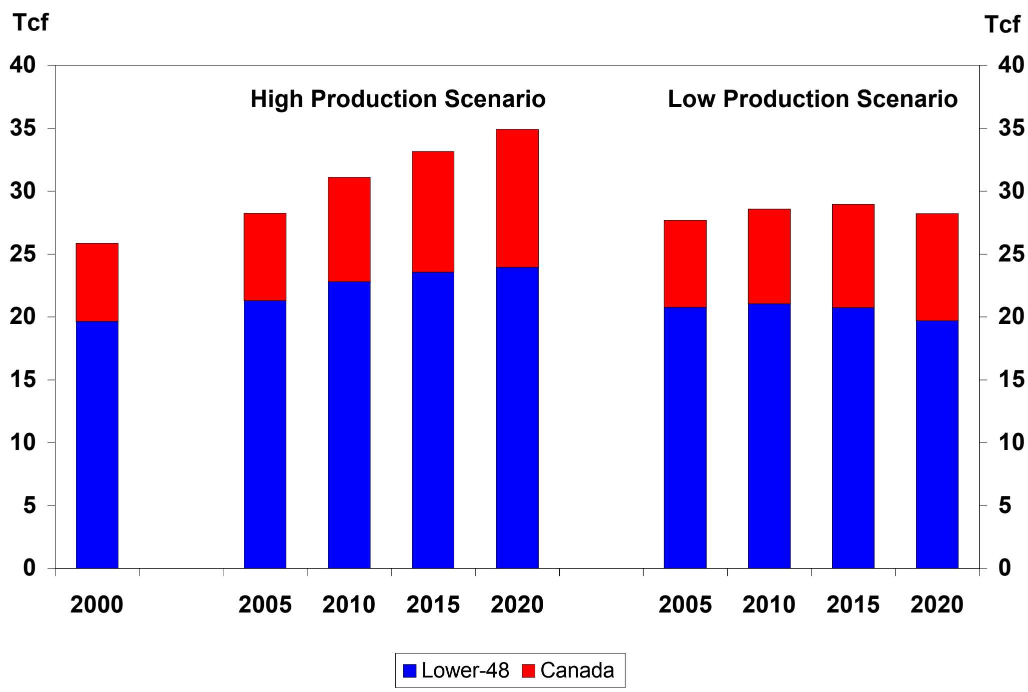
In the **Low Production Scenario**, Canadian gas production grows through 2015 and then tops out. In this scenario, little growth occurs in Western Canada gas production, reflecting the limited development of coalbed methane. Non-Western Canada gas production grows substantially, accounting for almost one fourth of Canadian gas production by 2020.

The cumulative discoveries between 2000 and 2020 in the two scenarios are 180-220 Tcf, of which about 130-150 Tcf are in Western Canada. The “ultimate” Canadian resource could grow 500-1,000 Tcf (150-300 Tcf would be in Western Canada) by 2020. While the total Canadian gas resource can grow at or ahead of the pace of reserve depletion through 2020, the Western Canada resource “depletion” is less clear. In the **High Production Scenario**, yields can remain reasonably stable, allowing gas production to grow in Western Canada with only modest at most upward pressures on gas prices. In the **Low Production Scenario**, resource growth struggles to keep pace with resource depletion in Western Canada, thus putting upward pressures on gas prices. The upside potential for Canada appears stronger than for the lower-48 at this point because only limited exploration to date has occurred in potentially prolific frontier regions that could begin production before 2020.

Final Observations

Figure 5.2 combines the prospects for lower-48 and Canada gas production in the two scenarios. In the **High Production Scenario**, lower-48/Canadian gas production exceeds 30 Tcf by 2010. Growth slows after 2010 unless the frontier areas of the lower-48 are opened to development. In this scenario, frontier moratorium areas begin production in 2010. By 2020, lower-48/Canadian gas production is almost 34 Tcf (93 Bcf/d) without the frontier areas and could approach 36 Tcf (99 Bcf/d) with them.

Figure 5.2
Lower-48/Canada Gas Production Scenarios



In the **Low Production Scenario**, prospects for increased gas production are limited, and production does not exceed 30 Tcf. These limited production growth reflects lesser advances in technology and industry practice over the period that are needed to expand the resource available for development and reduce the costs and risks associated with that development. In essence, the **Low Production Scenario** describes a situation in which the world of 2020 is largely unchanged from the world of 2000.

CHAPTER 6

CRITICAL ISSUES AND UNCERTAINTIES

CRITICAL ISSUES AND UNCERTAINTIES

Introduction

Prospects for increased North American gas production to supply a growing gas demand appear strong. While this growth could extend through 2020, significant challenges must be addressed in the course of achieving this growth. Principal among them are:

- North American *gas reserves inventories must be rebuilt* to support sustained growth in gas production

- the pace of *advances in technology and industry practice* and expanded industry perceptions of the "ultimate" resource base over the last decade must be maintained

- impacts of land restrictions on the *growth in North American gas production* must be weighed against the extent to which public policy may wish to encourage expanded use of gas.

Reserves Inventory

A large share of the growth in North American gas production from the mid-1980s into the 1990s came from drawing down the RP ratio. However, drawing down the RP ratio is only a short-term, one-time option. Below a particular level, the reserves inventory can only be drawn down at the expense of future growth or maintaining current gas production.

By the mid-1990s, RP ratios in the lower-48 were drawn down to levels that made it difficult for lower-48 gas production to grow on a sustained basis in the face of "normal" variations in gas drilling activity and its yields. As a result, lower-48 gas production has shown little growth since 1995. Although production has increased in some areas since the mid-1990s, these areas generally have high or growing RP ratios.

While gas reserves in Western Canada can support gas production near current levels and possibly some sustained, small growth, a return to the growths prior to 1997 would entail a significant increase in the Western Canada RP ratio. As a result, gas reserve additions in Western Canada would have to run well ahead of production replacement for several years or a multi-Tcf field be discovered. The critical challenge for industry is to rebuild the reserves inventory with minimum upward pressures on gas prices, which would negatively impact the economic attractiveness of gas sales in some markets.

However, Western Canada has a potential coalbed methane resource that could carry most future growth, if that resource is economic to develop. While the resource in-place is substantial, the ability of *current* technology and practices to produce coalbed methane economically are only just now being assessed. In fact, advances in technology and practice will probably be needed as well.

Gas production from the Deepwater Gulf of Mexico should grow substantially in the coming years. However, Shelf gas reserves are barely sufficient to sustain current production. If Shelf production is to stabilize, reserve additions would have to exceed production for several years. If Shelf production does not stabilize, this would limit the increase in Gulf of Mexico gas production.

Therefore, industry is faced with a dilemma. Current practice is to produce reserves as fast as possible. Unless the reserves inventory can be increased, prospects for sustained growth are uncertain, and rebuilding the reserves inventory could put significant upward pressures on near-term gas prices. The critical challenge will be to rebuild reserves inventory in a way that does not seriously weaken industry profitability or gas competitiveness with alternative fuels.

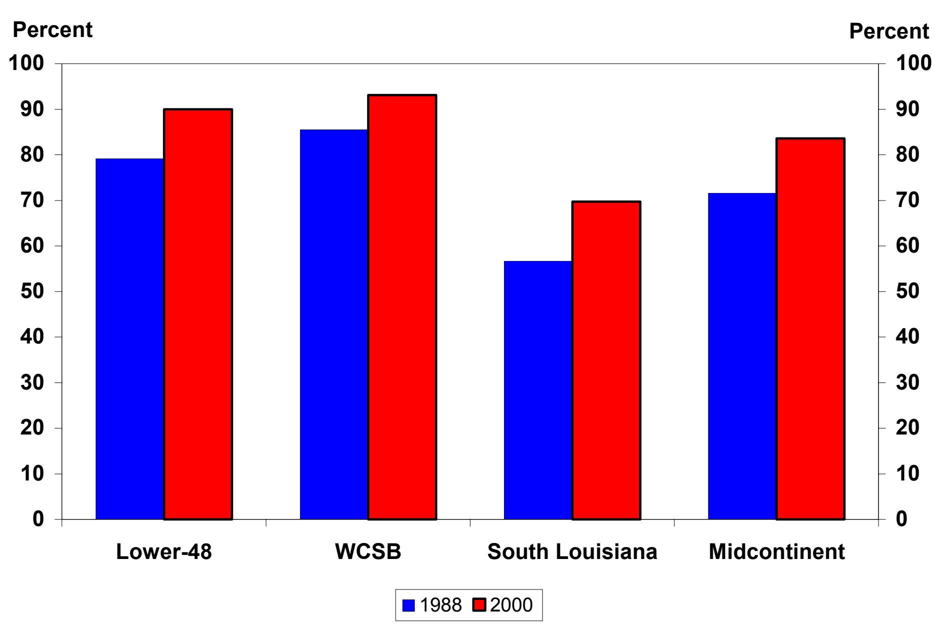
Technology and Practice

Advance in technology and industry practice have substantially reduced the costs and risks to develop gas production. New resources and new, deeper sediments have been developed at prices that would have been considered unacceptably low 20 years ago. The critical question is whether the pace of advance can be sustained.

Improved success rates for both wildcat and development drilling have contributed substantially to industry success in the last decade. Average wildcat success rates are now approaching 40%. The extent to which improvement can continue is uncertain, but wildcat success rates in the Permian Basin and Rocky Mountains now exceed 40%.

Lower-48 development success rates have also increased substantially, growing from an average 79% in 1988 to 90% in 2001. While improvements have occurred throughout the lower-48, development success rates in the Midcontinent and South Louisiana are still relatively low. Figure 6.1 presents development success rates for the lower-48, the Midcontinent, and South Louisiana.

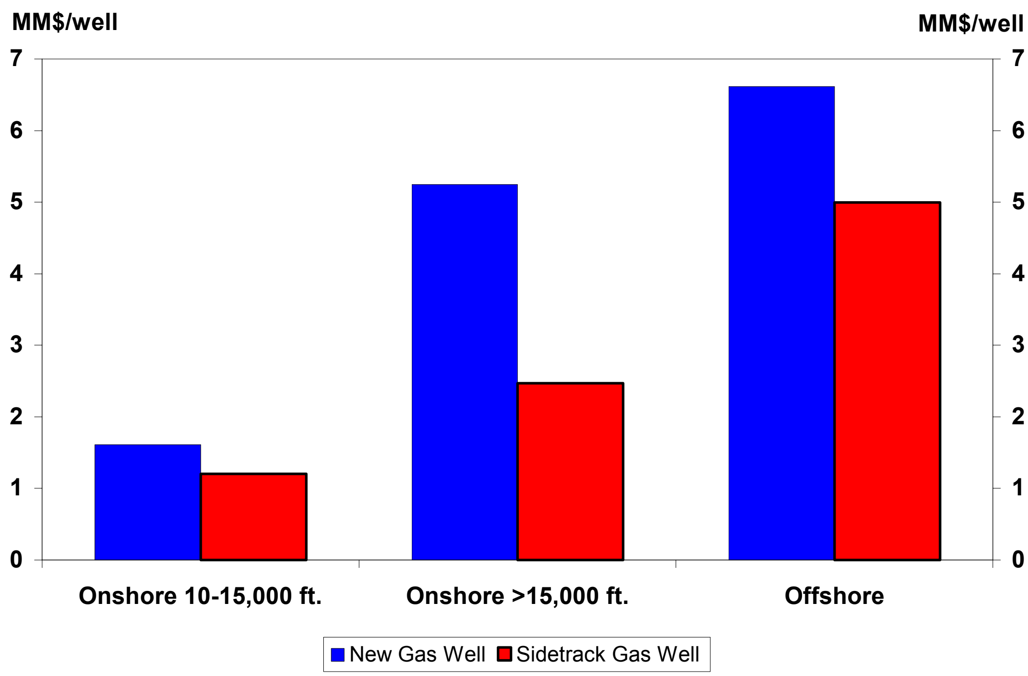
Figure 6.1
Development Well Success Rates



Prospects for increased production in both the Midcontinent and South Louisiana are limited, although significant resource potential still remains in both areas. In fact, the recent National Petroleum Council (NPC) study was quite optimistic about Midcontinent prospects. However, without improved success rates, production in these two areas is likely to show little growth and more likely to decline.

Another option to reduce the costs of adding new reserves, and thereby allow gas reserve inventories to be rebuilt with reduced upward cost pressures is to make increasing utilization of the large numbers of existing wells as re-entry points to drill "sidetracks." The Joint Association Survey (JAS) of drilling costs for 2000 (published by American Petroleum Institute) shows that sidetrack wells cost 25-50% less than a new well. Figure 6.2 compares drilling charges for deeper onshore gas wells and for offshore gas wells.

Figure 6.2
2000 Lower-48 Gas Well Charges



Overall, technology tends to lower the cost of reserves development by improving drilling techniques and by providing an exploratory foundation that reduces the number of dry holes drilled relative to successfully completed wells. In 2000, the *Joint Association Survey* reported a 51 percent increase in gas wells drilled, as well as, a 43 percent increase in total footage drilled for gas wells. Even though total expenditures increased 43 percent to over $10 billion for gas wells, the average and median cost of a gas well completion decreased about five percent.

Year-by year analysis of the JAS data requires a thorough understanding of drilling trends and geologic environments given cyclical interest in certain drilling targets. However it is clear that technology has improved drilling economics and provided additional recovery of gas-in-place.

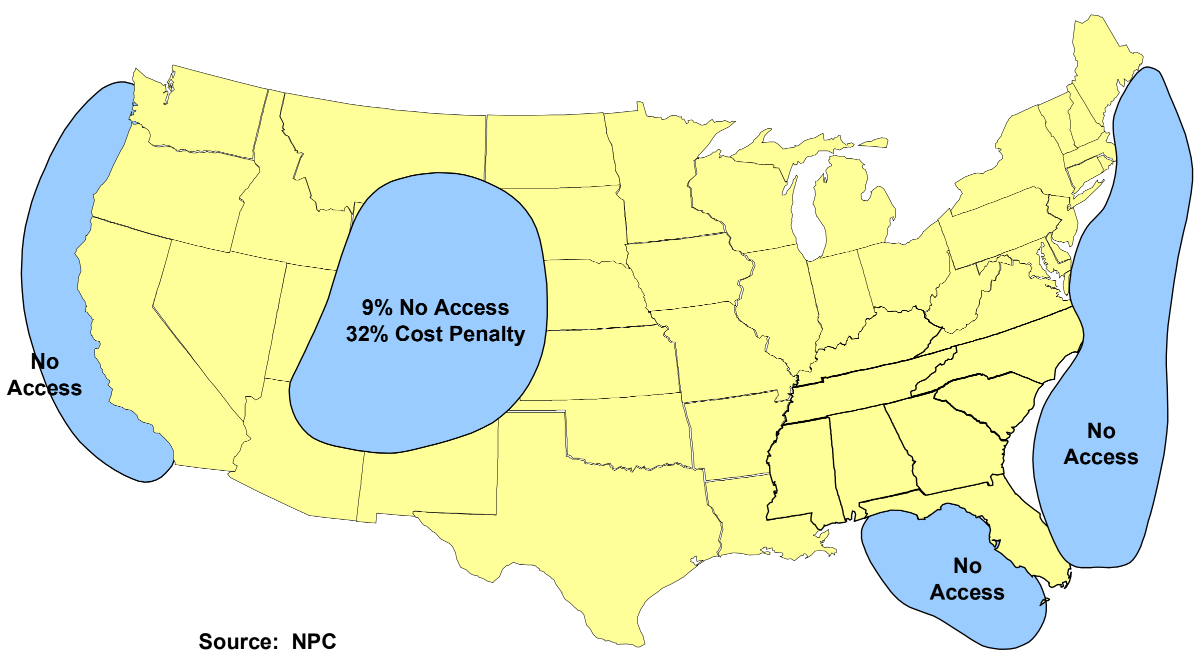
Land Restrictions

Figure 6.3 indicates the producing or potentially producing areas in the lower-48 where future development is subject to land restrictions. In the offshore regions of the Atlantic, Eastern Gulf, and Pacific, restrictions are total, either de facto or de jure. The Rocky Mountains have land restrictions, but they are not blanket. In the NPC study, 9% of its Rocky Mountain resource was estimated to be closed to development, and 32% of its resource potential would be higher cost to develop because of land restrictions.

If the offshore moratoria were lifted, production from the restricted offshore areas would probably not begin until the end of the decade. While this production would probably not even provide 10% of lower-48 gas production by 2020, it could provide most of the growth after 2010. Thus, if North American gas demand is to grow over the next 20 years *and* North American gas production to grow as well, the restricted offshore areas are critical to continued, growth after 2010.

In the Rocky Mountains, the Unita/Piceance Basin and Green River basins currently appear to provide the better opportunities for expansions to "ultimate" resource prospects. However, the NPC study indicates that land restrictions are stronger in these basins. Thus, while Rocky Mountain gas production is likely to continue to grow over the next 20 years, land restrictions might keep that growth closer to the trajectory in the **Low Production Scenario** (4.2 Tcf in 2020) than in the **High Production Scenario** (4.9 Tcf in 2020).

Figure 6.3
Lower-48 Resource Potential Restrictions



Source: NPC

Final Observations

Gas production in Canada and the lower-48 United States have strong opportunities to grow and play a significant role in meeting increased North American gas demand over the next 20 years. In any outlook, however, uncertainties exist. Through 2010, the uncertainties are more along the lines of whether technology and industry practice can continue to advance as they have over the last decade. In the longer term, issues of land access become increasingly critical for increased lower-48 gas production. Land restrictions may result in lower-48 gas production peaking within 10-12 years and possibly beginning to erode towards the end of the next decade.

APPENDIX

GLOSSARY OF TERMS

GLOSSARY OF TERMS

Natural gas is a mixture of hydrocarbons and some non-hydrocarbons existing in the gaseous phase or in solution with crude oil in underground reservoirs. The principal hydrocarbons in the mixture are methane, ethane, propane, butanes, and pentanes plus. Typical non-hydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. The following is a glossary of terms describing natural gas production and reserves that are used in the report. The glossary is based on definitions developed by the U.S. Department of Energy, Energy Information Administration and the Canadian Association of Petroleum Producers.

Volumes

Natural gas volumes can be produced from either oil wells or gas wells. As a result, gas volumes can be characterized as either non-associated or associated-dissolved.

Associated-Dissolved Gas. The combined volume of natural gas that occurs in crude oil either as free gas (associated) or as gas in solution with crude oil (dissolved gas). This gas is produced by oil wells, and is sometimes referred to as casinghead gas.

Non-Associated Gas. Natural gas not in contact with significant volumes of crude oil in a reservoir and produced from gas wells.

Reserves

Government agencies report natural gas reserves differently in the United States and Canada. In the United States, proved reserves are reported. The Canadian government reports established reserves. Proved reserves are a subset of established reserves.

Proved Reserves. Proved reserves are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under *existing* economic and operating conditions. Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation tests, or if economic producibility is supported by core analyses and/or electric or other log interpretations. Volumes of natural gas in underground storage are not considered to be proved reserves.

Established Reserves. Those reserves recoverable under current technology and *present and anticipated* economic conditions, specifically proved by drilling, testing, or production, plus that judgment portion of contiguous, recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.

Production

Natural gas production is generally measured at three points: wellhead, lease boundary, or downstream (outside lease) natural gas processing plants. Production at the wellhead is the largest hydrocarbon and non-hydrocarbon before any gas processing or re-injection. For example, 3.2 Tcf (8.8 Bcf/d) of gas was produced at the wellhead on the North Slope of Alaska in 2001, but 3.0 Tcf (8.1 Bcf/d) was re-injected into producing oil reservoirs, leaving on 0.3 Tcf (0.7 Bcf/d) of marketable gas . Each production volume can be worked back to a reserves estimate.

Wellhead Production. This production is the total volume of *all* gases that are produced. It is referred to as “gross” production in the United States and “raw” production in Canada. Wellhead production is reported for both oil wells (associated-dissolved) and gas wells (non-associated).

Marketed Production. The volume of natural gas leaving the lease. It is the volume remaining less (1) the volume returned to underground producing reservoirs in cycling, repressuring of oil reservoirs, and conservation operations; (2) any volumes of gas that are vented or flared; and (3) shrinkage due to removal of natural gas liquids in lease and/or field separation facilities and removal of non-hydrocarbon gases where they occur in sufficient volumes to render the gas unmarketable. Some natural gas liquids may remain in the gas stream and may be separated at natural gas processing plants located outside the lease along gas transmission lines. The U.S. Department of Energy sometimes refers to marketable gas as *wet after lease separation.* Both Canadian and U.S. governments report marketed gas production reserves and production volumes. Because marketed gas production is reported on a lease basis, gas production can be allocated to oil wells and gas wells.

Dry Production. This term is used in the United States, but not in Canada. This is the volume of natural gas less the shrinkage of gas volumes due to liquids extraction at natural gas processing plants outside the lease along transmission lines. Because gas processed outside the lease is a changing combination of gas well and oil well production, only a total dry gas production number is reported.