2. Access to Supplies and Production Areas

Natural gas production patterns in the lower 48 States have changed in recent years as new fields have been brought on line and older gas-producing areas have declined in importance. For example, the eighth largest gas field in the United States in 1996 in terms of output, Bob West in southern Texas, was discovered only in 1990 and as late as 1993 did not even figure among the top 30 producers. Also, new technology has rejuvenated older fields and allowed production from fields previously thought uneconomic.

The shifts in regional production will affect existing pipeline routes, reducing flows along some, while increasing flows along others. Some regional production increases from new gas fields in the Rocky Mountain area and New Mexico will require additional capacity to transport the gas to markets. The Gulf Coast region has seen a substantial increase in production over the past several years and, although traditionally served by an extensive pipeline network, will probably require the addition of new capacity. Meanwhile, production in the Anadarko and Arkoma Basins declined during the first half of the 1990s.

This chapter discusses U.S. natural gas deliverability at the wellhead through 2000 and the capability of the pipeline network to receive and export that gas through the national network grid. The analysis focuses on eight producing areas that roughly correspond to major geologic basins in the lower 48 States (Figure 2), as well as imports from Canada. Relatively new producing regions (in terms of average field age) covered in this chapter include the offshore Gulf of Mexico; major fields in the Rocky Mountain States of Utah, Colorado, and Wyoming; and the San Juan Basin of New Mexico. Older producing regions examined include the Permian Basin; the onshore Gulf Coast of Texas and Louisiana; the Anadarko and Arkoma basins in Oklahoma, Kansas, and Arkansas; the fields of East Texas; and the Appalachian Basin.[13] Although a relatively minor gas producer, the Appalachian Basin region is notable because of its proximity to major markets in the Northeast. Canada has sharply increased gas exports to the United States during the 1990s, growing as a major source of deliverability in the lower 48 States.

Alaska is not included as a supply area in this study because its natural gas production is not destined for U.S. markets in the lower 48 for some time to come and therefore does not directly affect U.S. gas deliverability within the time frame of the analysis.

U.S. Natural Gas Supplies by Region, 1990-2000

Total natural gas production in the lower 48 States has shown an upward trend during the 1990s, rising 5 percent from an average 47.7 billion cubic feet (Bcf) per day (17.4 trillion cubic feet (Tcf) on an annual basis) in 1990 to 50.1 Bcf per day (18.4 Tcf per year) in 1996 (Table 2), its highest level since the early 1980s. Higher gas demand and stable prices are projected to raise production in the lower 48 to about 54 Bcf per day (19.8 Tcf per year) in 2000. The 1.9-percent average annual growth rate forecast for the period 1996 through 2000 is more than double the production growth rates of the first half of the 1990s.[14]

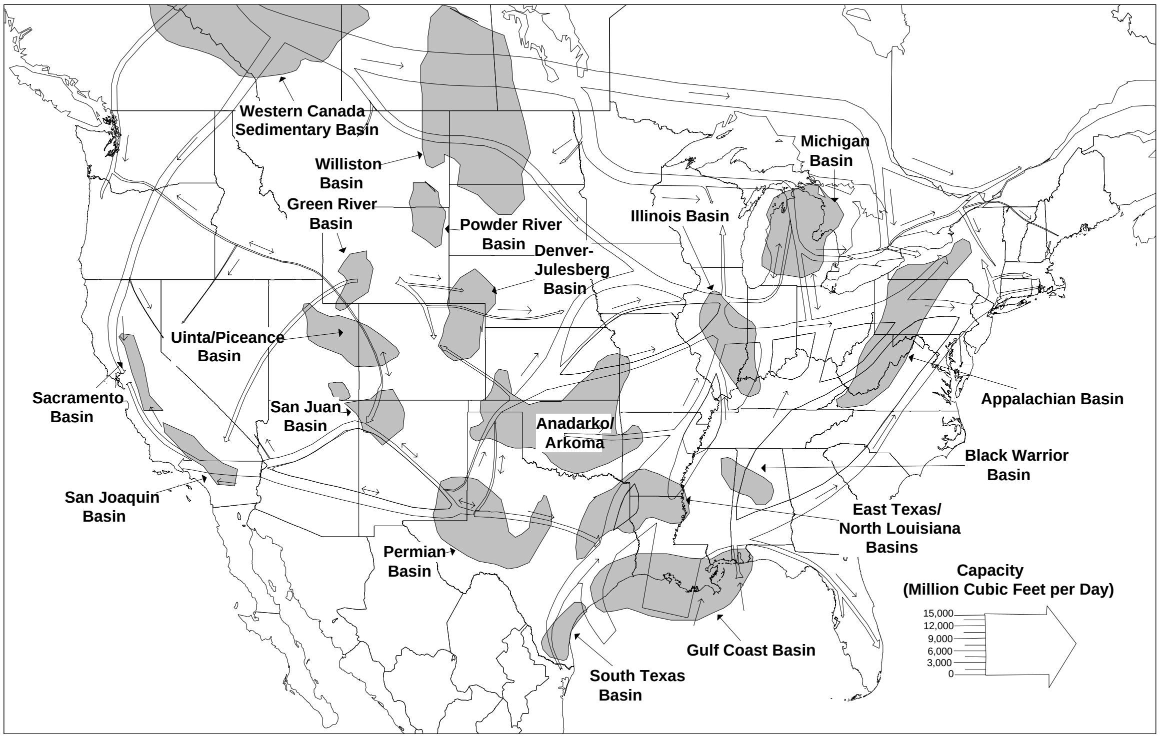
Lower 48 gas reserves increased to 156 Tcf in 1996, marking the third consecutive year of higher reserve levels although still slightly below the 1990 level of 160 Tcf. This recent trend is expected to continue. Various factors, such as improved well completions, advanced stimulation technology, and improved seismic technology, have allowed producers to maximize gas output from existing fields, resulting in a decline in the ratio of reserves to production since 1990. The near-term supply outlook for natural gas shows expanded production through 2000, reflecting the recent production trends as well as the substantial volume of remaining resources.[15] One recent study estimated remaining recoverable gas resources at 929 Tcf as of December 31, 1996, suggesting

[13]The regional data were aggregated from data by State and sub-State areas. The lack of strict correspondence between the basins and these data means that portions of basins may be excluded, or other lesser basins may be included in the regional estimates. For expository purposes, the regions, in some cases, are treated as equivalent to the major basins within the regions.

[14]Unless otherwise noted, all forecasts are derived from data in the Energy Information Administration (EIA) publication *Annual Energy Outlook 1998 With Projections to 2020*, DOE/EIA-0383(98) (Washington, DC, December 1997). Historical data for the lower 48 States are from EIA's *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997), and earlier editions of this report. The lower 48 totals are disaggregated to regional estimates, based on relative dry gas production values as reported in the EIA report *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996*, DOE/EIA-0216(96) (Washington, DC, December 1997), and earlier editions.

[15]Energy Information Administration, *Annual Energy Outlook 1998*, (Washington, DC, December 1997).

Figure 2. Major Natural Gas Producing Basins and Transportation Routes to Market Areas



Correspondence to Major Natural Gas Producing Regions

Producing Region	State or Substate Regions	Basins Contained Whole or in Part
Gulf Coast	South Louisiana (onshore) Texas RRC Districts 1, 2, 3, 4	Gulf Coast and South Texas Basins
Anadarko/Arkoma	Arkansas Kansas Oklahoma Texas RRC District 10	Anadarko/Arkoma Basin
Permian Basin	New Mexico, East Texas RRC Districts 7B, 7C, 8, 8A, 9	Permian Basin
Rockies	Colorado Utah Wyoming	Uinta/Piceance, Julesberg, Powder River, and Green River Basins
East Texas	North Louisiana Texas RRC Districts 5, 6	East Texas/North Louisiana Basins
San Juan Basin	New Mexico, West	San Juan Basin
Appalachian	New York Ohio Pennsylvania Virginia West Virginia	Appalachian Basin
Other Onshore	Alabama, California (onshore), Florida, Kentucky, Michigan, Mississippi, Arizona, Illinois, Indiana, Maryland, Missouri, Montana, Nebraska, Nevada, North Dakota, Oregon, South Dakota, and Tennessee	Williston, Sacramento, San Joaquin, Illinois, Michigan, and Black Warrior Basins
Offshore	Federal waters of the Gulf of Mexico, and State waters of California, Alabama, Louisiana, and Texas	

Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of December 1997.

Table 2. Natural Gas Production and Supplies in the Lower 48 States, by Region, 1990-2000

Region	Annual Gas Supplies (billion cubic feet per year)			Daily Gas Supplies (billion cubic feet per day)			Change in Gas Supplies (percent increase/decrease)		Share of Total Supplies (percent)		
	1990	1996	2000 (forecast)	1990	1996	2000 (forecast)	1990-96	1996-2000 (forecast)	1990	1996	2000 (forecast)
Lower 48 Production											
Gulf Coast	3,130	3,340	3,432	8.6	9.1	9.4	6.4	2.8	16.5	15.7	14.4
Anadarko/Arkoma	3,339	2,929	2,967	9.1	8.0	8.1	-12.5	1.3	17.6	13.8	12.4
Permian Basin	1,663	1,621	1,890	4.6	4.4	5.2	-2.8	16.6	8.8	7.6	7.9
Rockies	911	1,497	1,668	2.5	4.1	4.6	63.9	11.5	4.8	7.0	7.0
East Texas	1,109	1,153	1,185	3.0	3.2	3.2	3.7	2.8	5.8	5.4	5.0
San Juan Basin	511	988	1,101	1.4	2.7	3.0	92.9	11.5	2.7	4.6	4.6
Appalachian Basin	496	504	583	1.4	1.4	1.6	1.3	15.7	2.6	2.4	2.4
Other Onshore	844	828	1,073	2.3	2.3	2.9	-2.2	29.6	4.5	3.9	4.5
Total Onshore	12,003	12,859	13,899	32.9	35.1	38.0	6.8	8.1	63.3	60.4	58.2
Offshore	5,425	5,491	5,881	14.9	15.0	16.1	0.9	7.1	28.6	25.8	24.6
Total Lower 48	17,428	18,350	19,780	47.7	50.1	54.0	5.0	7.8	91.9	86.2	82.8
Lower 48 Imports											
From Canada	1,448	2,883	3,910	4.0	7.9	10.7	98.6	35.6	7.6	13.5	16.4
Total Lower 48	1,532	2,937	4,120	4.2	8.0	11.3	91.2	40.3	8.1	13.8	17.2
Total Lower 48 Supplies	**18,960**	**21,287**	**23,900**	**51.9**	**58.2**	**65.3**	**12.0**	**12.3**	**100.0**	**100.0**	**100.0**

Sources: **1990-96 Data:** Energy Information Administration (EIA), *Natural Gas Annual 1996* (September 1997) and earlier editions. Production volumes by regions were derived based on relative dry gas production values published in *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996* (December 1997) and earlier editions. **2000 Forecasts:** EIA, *Annual Energy Outlook 1998* (*AEO*) (December 1997). When regions differed between the *Natural Gas Annual* and the *AEO*, regional production volumes were projected for 2000 by applying the growth factor for the *AEO* region between 1996 and 2000.

adequate domestic gas supplies through the near-term perspective of the present analysis.[16]

While higher gas production in the lower 48 States contributed to increased U.S. gas supplies between 1990 and 1996, the source of the largest portion of the increase was imports from Canada. Benefiting from strong U.S. demand and a more open trade environment, Canadian gas exports to the United States nearly doubled between 1990 and 1996 and accounted for about two-fifths of the increase in U.S. gas supplies during this period. By 2000, imports of natural gas from Canada are projected to account for 16 percent of U.S. gas supplies, more than double their 1990 share.

The concentration of increased gas supplies through 2000 in a small number of areas—Canada, the Rocky Mountain area, the Permian Basin, the San Juan Basin of New Mexico, and the offshore/onshore Gulf—raises concerns about the ability of the pipeline system and other infrastructure to meet increased demand for U.S. gas deliverability through the year 2000. Of the 7.1 Bcf per day (2.6 Tcf) in additional U.S. gas supplies anticipated between 1996 through 2000, imports from Canada are likely to represent about two-fifths of supply growth. Key domestic regions contributing to the supply rise are the offshore and Permian Basin regions with 15 and 10 percent of the total increase, respectively (Table 2).

In 1996, the United States had nearly 302,000 producing gas wells and gas-condensate wells,[17] as well as a very large number of oil wells, yielding approximately 50 Bcf of natural gas per day (18.4 Tcf per year). The largest gas-producing region in the lower 48 States is the offshore region, followed by the onshore Gulf Coast, the Anadarko/Arkoma Basins, the Permian Basin, and the Rockies. Together, these five regions accounted for 81 percent of total U.S. dry gas production in 1996. Eighty-six percent of U.S. consumption is met by domestic producers, while the remainder is imported mostly from Canada. The following sections highlight the contribution of each major supply region to gas supplies and deliverability in the lower 48 States.

[16] *Remaining recoverable gas resources* are those volumes producible with current recovery technology and efficiency but without reference to economic viability. The estimate of 929 trillion cubic feet of remaining recoverable gas resources is published in the report *Potential Supply of Natural Gas in the United States*, Potential Gas Agency, Colorado School of Mines (March 1997).

[17] Energy Information Administration, *Natural Gas Annual 1996*, DOE/EIA-0137 (Washington, DC, September 1997).

Offshore Gulf of Mexico

The top gas-producing region in the lower 48 States is the offshore region, where production flows almost exclusively from the Offshore Gulf of Mexico. The Gulf accounted for almost 30 percent of natural gas production (Figure 3) and more than one-fifth of proved reserves[18] (Table 3) in the lower 48 in 1996. The recent rebound in offshore exploration and development activity is likely to make the offshore region an important source of increased gas supplies during the late 1990s. Recent changes in the sources of gas production in the Gulf in favor of associated gas and deep water gas have major implications for future gas deliverability from this region and its impact on regional markets.

Major plays in the Gulf of Mexico are found in the Flexure Trend, the Norphlet Trend, the Destin Dome, subsalt, and deep water fields. The Flexure Trend extends from Mobile Bay to Mexico and includes fields in waters deeper than 600 feet; estimated productive capacity in the Flexure Trend was about 1.2 Tcf in 1996.[19] The Norphlet Trend is an extension of the Flexure Trend stretching from Alabama to Florida containing fields at 600 to 2,000 feet of depth. Production in the Norphlet Trend was about 1 Tcf in 1996. The Destin Dome, a part of the Norphlet Trend located off the coast of the Florida Panhandle, is estimated to contain 3 Tcf of potential reserves. However, significant production here is not likely to begin until around 2000 and will therefore have minimal impact on U.S. gas deliverability in the near term.

The collapse of oil and gas prices in the mid 1980s caused a reduction in overall exploration and development activities in the Gulf that continued into the early 1990s. As the average U.S. wellhead price fell by more than two-fifths in real terms (1996 dollars) between 1985 and the early 1990s,[20] offshore gas production was hit harder than onshore production because of the rapid depletion of known deposits in shallow waters and higher increased risks and costs associated with exploration and development of gas in deep water. Between 1990 and 1992, offshore gas production declined by 8 percent because of the lack of reserves replacement. Total offshore reserves shrank 10 percent between 1990 and 1992.

The large fields in the deep waters, combined with cost-cutting new technologies, have greatly improved the economics of offshore gas production, raising offshore output more than 13.0 percent between 1992 and 1996 to a level of 15.0 Bcf per day (5.5 Tcf per year). A 12-percent increase in average gas wellhead prices over the average from 1990 through 1992 (in constant 1996 dollars), coupled with a one-third decline in finding costs (also in 1996 dollars), contributed to a dramatic improvement in the profitability of offshore gas production. According to one source,[21] offshore gas production by 1995-96 was profitable at average wellhead prices of only $1.75 per thousand cubic feet, down from a profitability threshold estimated at $2.50 per thousand cubic feet (in current dollars) in 1991-92. With 1996 U.S. wellhead prices averaging $2.17 per thousand cubic feet, offshore gas production had become profitable after a high degree of unprofitability during the late 1980s and early 1990s.

The very high exploration and development (E&D) expenditures associated with offshore projects, more than $1 billion in some cases, are declining generally as companies gain experience with more challenging deep water and subsalt projects. Both project time horizons and platform costs are shrinking dramatically. For example, the capital portion of daily production costs for Shell's Ursa tension leg platform (TLP), due to begin production in 1999, is projected to be slightly more than half that of Auger, Shell's first TLP installed in 1994.[22] Offshore projects partially compensate for higher upfront expenditures with faster recovery of reserves through higher flow rates. The faster depletion of offshore wells requires more continuous exploration activity to maintain production levels. The Outer Continental Shelf (OCS) Deep Water Royalty Relief Act (DWRRA),[23] signed in November 1995, has also improved the economics of offshore production. The DWRRA provides for a waiver of royalty payments for production from new leases and certain other deep water leases.[24]

Overall, offshore gas production is projected to grow 7 percent from 15.0 Bcf per day (5.5 Tcf per year) in 1996 to 16.1 Bcf per day (5.9 Tcf per year) in 2000. A key source of expanded production is likely to be associated-dissolved (AD) gas from crude oil production (accounting for one-fourth of the incremental production), although expanded output of

[18]Proved reserves of natural gas are the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[19]WEFA, *Natural Gas Outlook* (Spring/Summer 1997), p. 6.9.

[20]Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report 1996,* DOE/EIA-0216(96) (Washington, DC, December 1997), p. 10.

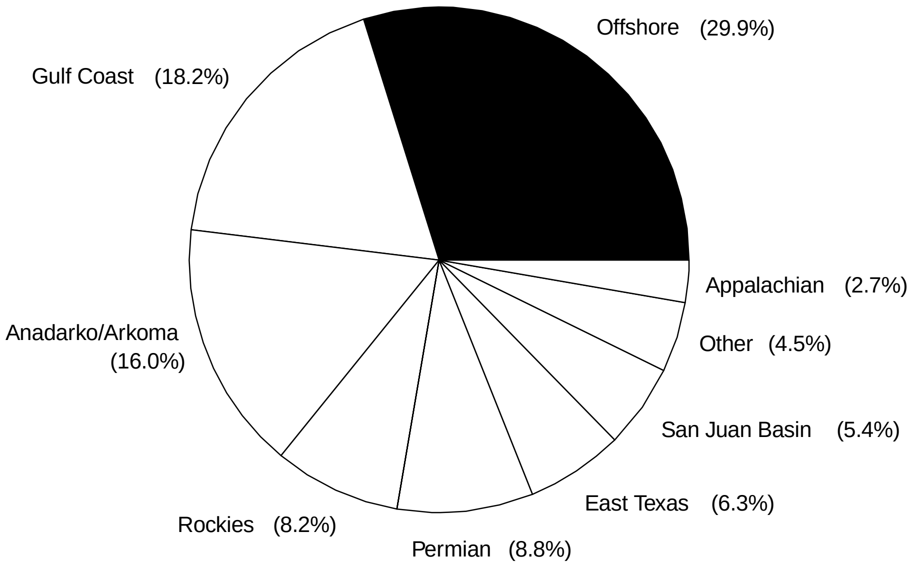
[21]James Dodson and Leonard LeBlanc, "U.S. Gulf Rebound to Continue in 1995," *Offshore* (January 1995), p. 20.

[22]"Deepwater, subsalt projects open new era for Gulf of Mexico actions," *Oil and Gas Journal* (January 20, 1997), p. 37.

[23]The law provides royalty relief to oil and gas fields in the Central and Western Gulf of Mexico that would not be economic to produce without royalty relief. In particular, fields that did not produce prior to November 28, 1995, and meet Minerals Management Service (MMS) economic determinations may receive royalty suspension volumes of at least 17.5 million barrels of oil equivalent (BOE) in 200 to 400 meters of water, 52.5 million BOE in 400 to 800 meters of water, and 87.5 million BOE in more than 800 meters of water.

[24]"Deepwater royalty relief product of 3 ½ year U.S. political effort," *Oil and Gas Journal* (April 1, 1996), pp. 45-56.

Figure 3. Lower 48 Natural Gas Production by Region, 1996
(Share of Total in Percent)



Total lower 48 production is 18.4 trillion cubic feet

Source: Energy Information Administration. **Total 1996 Production:** *Natural Gas Annual 1996* (September 1997). **Shares by Region:** *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996* (December 1997).

Table 3. Lower 48 Dry Natural Gas Proved Reserves and Reserves-to-Production Ratio, 1990-1996

	Proved Reserves (billion cubic feet)			Proved Reserves-to-Production Ratio		
Region	**1990**	**1995**	**1996**	**1990**	**1995**	**1996**
Gulf Coast	21,325	19,186	20,050	7.0	6.1	6.0
Anadarko/Arkoma	31,986	28,008	26,629	9.9	9.8	9.1
Permian Basin	15,718	13,534	14,053	9.8	8.5	8.6
Rockies	16,009	21,002	21,663	18.1	14.1	14.4
East Texas	10,216	10,376	11,083	9.5	9.2	9.6
San Juan Basin	14,004	14,624	13,695	28.3	14.9	13.8
Appalachian Basin	5,633	7,068	7,674	11.7	15.3	15.2
Other Onshore	9,584	8,027	8,653	11.7	10.1	10.4
Total Onshore	**124,475**	**121,825**	**123,500**	**10.7**	**9.8**	**9.6**
Offshore	35,571	33,824	33,680	6.8	6.6	6.1
Total Lower 48	**160,046**	**155,649**	**157,180**	**9.5**	**8.9**	**8.5**

Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996* (December 1997).

deep water and subsalt gas also contribute to production gains.

A more than one-third increase in Gulf oil production since 1990 has led to higher output of AD gas, which reached 2.2 Bcf per day (0.8 Tcf), or 15 percent of total offshore gas production in 1996. Based on Energy Information Administration (EIA) projections of Gulf oil output through 2000,[25] AD gas will rise by another 0.25 Bcf per day. The considerable future potential of AD gas is demonstrated by its large share of total offshore reserves, which grew from less than 20 percent in 1990 to 22.4 percent in 1996.

The growing influence of AD gas in the Gulf has provided producers with some logistical challenges and has possible implications for regional gas prices. Because natural gas is consumed in accordance with seasonal market demand, the fairly steady recovery schedule of AD gas from oil projects results in some gas being produced during periods of minimal demand. Such an inelastic production schedule, characteristic of AD gas, could depress gas prices in the Gulf region during periods of minimal demand.

Expanding production of AD gas in the Gulf of Mexico has therefore led to increased use of storage along the Gulf Coast, so that producers can better match supplies to seasonal demand. The anticipated increase in AD gas production through 2000 is being accompanied by underground storage expansions under development in Texas and Louisiana with a combined daily deliverability of 2 Bcf per day.[26] Underground storage capacity is also being expanded near major market areas in the Northeast and Midwest, where up to 1.5 Bcf per day in daily deliverability could be added in each region by 2000. However, most likely not all planned capacity additions will be realized.

Other offshore production trends affecting gas deliverability include a movement to the deeper offshore and an emerging interest in subsalt deposits. While wells in water deeper than 1,000 feet (roughly 305 meters) have been producing gas in the Gulf since the late 1970s, their role in offshore gas production was minimal until recent technological advances, such as improved 3-D seismic surveys and floating production systems (see Box, "Technological Improvements"), allowed for the discovery and development of several large deep water deposits. By 1996, 20 new deep water prospects began producing, with a similar number of startups expected from 1997 through 2000.[27] Activity in the deep waters of the Gulf of Mexico is expected to remain strong as leasing activity has responded to the royalty relief act incentives. The number of blocks receiving bids in the sales since the DWRRA was signed in November 1995 has risen substantially, with blocks in at least 800 meters numbering seven times the earlier count (Table 4). Some of the deep water capacity coming on stream during the 1990s is replacing depleted deposits in shallower water. Deep water gas production will contribute to a net increase in offshore production during the latter half of the decade.

Advances in 3-D seismic interpretation and drilling through thick sections of salt have made it possible to develop resources under sheets of salt that are believed to extend under more than half of the Gulf of Mexico. In 1993, the first subsalt find to be commercially developed, Mahogany, was discovered, followed by seven more in 1994 and 1995. Even though some initial successes generated considerable interest in the estimated 15 trillion cubic feet or more of undiscovered subsalt recoverable gas resources, significant exploratory risks remain and subsalt gas supplies are not expected to be as significant in the near term as deep water gas. Less than 1 Bcf per day of total additional production capacity is likely from new subsalt gas through the year 2000. In the longer term, which is beyond the scope of this report, subsalt gas production could have greater impact on offshore gas deliverability.

The steady movement of gas production into deeper, more remote environments further offshore raises several challenges related to delivery of gas from the field. They include building the offshore pipeline network to bring the new deep water gas ashore and expanding existing onshore pipeline capacity to accommodate the additional gas (see Appendix B, "Natural Gas Pipeline and System Expansions, 1997-2000").

Onshore (Texas and Louisiana) Gulf Coast

The Gulf Coast region, containing the coastal East and Southeast Texas (Railroad Commission Districts 1, 2, 3, and 4), and Southern Louisiana, produced more gas than any other onshore region in the United States in 1996 after trailing the Anadarko and Arkoma Basins in the early 1990s. Gas production grew by roughly 6 percent between 1990 and 1996 and at 9.1 Bcf per day (3.3 Tcf per year) accounted for nearly

[25] Energy Information Administration, *Annual Energy Outlook 1998 With Projections to 2020*, DOE/EIA-0383(98) (Washington, DC, December 1997).

[26] See Energy Information Administration, "U.S. Underground Storage of Natural Gas in 1997: Existing and Proposed," *Natural Gas Monthly*, DOE/EIA-0130(97/09 (Washington, DC, September 1997), pp xxi-xli.

[27] Chris C. Oynes, Regional Director, Gulf of Mexico Region, Minerals Management Service, presentation at the OCS Workshop, American Association of Professional Landsmen (Houston, TX, January 22, 1998).

Table 4. Central and Western Gulf of Mexico Lease Sales Before and After the Royalty Relief Act

Block Water Depth (meters)	Number of Blocks Receiving Bids			
	1994	1995	1996	1997
0-200	490	516	637	542
200-400	18	50	69	52
400-800	28	83	113	104
800+	49	214	722	1,138
All Depths	**585**	**863**	**1,541**	**1,836**

Note: The Outer Continental Shelf Deep Water Royalty Relief Act was signed in November 1995.

Source: Derived from a speech by Chris C. Oynes, Regional Director, Gulf of Mexico Region, Mineral Management Service, to the OCS Workshop, American Association of Professional Landsmen (Houston, TX, January 22, 1998).

16 percent of U.S. gas supplies in the latter year. The two largest fields in the region, Giddings and Bob West, are located in southern Texas. They produced a daily average of 1.1 and 0.3 Bcf of wet gas,[28] respectively, in 1996 (Table 5). Most of the onshore Gulf Coast's production is from nonassociated gas, with AD gas accounting for only about one-tenth of regional gas production and reserves.

A high degree of exploration activity, enhanced by the use of horizontal and multilateral drilling, is yielding impressive results, particularly around the Austin Chalk Trend. In March 1997, one well set an onshore U.S. horizontal well record, flowing an average of 84 million cubic feet per day, which was exceeded by another with an average flow of 100 million cubic feet per day in April 1997. Technology has also been employed in the onshore Gulf region to expand flow at producing fields, with a major developer of the Wilcox/Lobo Trend achieving a 75-percent success rate in 1994 using 3-D seismic technology and improved fracturing fluids.

Proved reserves in the onshore Gulf Coast region declined between 1990 and 1996 to the equivalent of 6 years' worth of production, the lowest reserves-to-production ratio among major onshore gas-producing regions (Table 3). Reserves declined by more than 15 percent between 1990 and 1993 but have since partially recovered to 20.1 Tcf in 1996 as increased exploration activity from 1994 through 1996 found increased gas at existing fields and some new finds.

The new Texas finds in the Austin Chalk Trend, along with the potential for additional finds in the Louisiana portion of this trend, suggest further near-term growth potential for onshore Gulf Coast gas output. Between 1996 and 2000, gas production in the onshore Gulf Coast region is forecast to rise almost 3 percent to 9.4 Bcf per day (3.4 Tcf per year). Estimates of productive capacity show that surplus wellhead deliverability during January, the peak of the heating season (November 1 through March 31), declined from 23 percent of total deliverability in 1990 to an estimated 14 percent in 1996 (Table 6).

[28]*Wet gas* refers to produced natural gas that contains liquid hydrocarbons that are removed at a natural gas plant. *Dry gas* is the gas remaining after liquids removal.

Anadarko and Arkoma Basins

The Anadarko/Arkoma region comprises Oklahoma, Kansas, Arkansas, and the Texas Panhandle area (Railroad Commission District 10). It was the largest onshore gas-producing region in 1990, when production averaged 9.1 Bcf per day (3.3 Tcf per year) (Table 2). However, a sharp production decline in Oklahoma reduced the region's gas production by more than 12 percent between 1990 and 1996 to a level of 8.0 Bcf per day (2.9 Tcf per year). A major factor in declining regional gas output was a nearly 30-percent contraction of productive capacity between 1990 and 1996. By the mid-1990s, Anadarko/Arkoma had fallen to second place behind the Gulf Coast among onshore regions in terms of gas output volumes. It does remain the top onshore region in terms of proved reserves, despite a 17-percent drop in Anadarko/Arkoma proved reserves, from 32.0 Tcf in 1990 to 26.6 Tcf in 1996 (Table 3).

The largest gas field in Anadarko/Arkoma is the giant Hugoton gas field in Kansas, which dates from 1922 (Table 5). Despite its age, Hugoton was the second largest U.S. gas field ranked by annual production in 1996 (1.5 Bcf per day of wet gas) and is the largest U.S. field in terms of cumulative production (about 22 Tcf). Hugoton, whose production comes from low permeability sandy carbonate reservoir rocks, occupies much of the western half of Kansas and extends south into Oklahoma and the Texas Panhandle.

Hugoton's gas output has been raised in recent years through the practice of more intensive drilling in existing fields and through some new finds, including those along the Eubank channel. This helped to offset significant declines in production at other Anadarko/Arkoma fields, particularly in

Table 5. Top 10 Fields in the Lower 48 States Ranked by Natural Gas Production, 1996
(Billion Cubic Feet)

Rank	Field Name	Location: State	Location: Producing Area	Year of Discovery	1996 Average Daily Production	1996 Annual Production	Share of Lower 48 Production (percent)
1	Basin	NM	San Juan Basin	1947	1.83	668.8	3.5
2	Hugoton Gas Area	KS/OK/TX	Anadarko/Arkoma	1922	1.52	558.0	2.9
3	Blanco	NM/CO	San Juan Basin	1927	1.50	549.0	2.8
4	Giddings	TX	Onshore Gulf Coast	1960	1.05	386.0	2.0
5	Carthage	TX	East Texas	1936	0.56	203.5	1.1
6	Mobile Bay	AL	Offshore Gulf of Mexico	1985	0.36	131.3	0.7
7	Panhandle West	TX	Anadarko/Arkoma	1918	0.35	129.8	0.7
8	Bob West	TX	Onshore Gulf Coast	1990	0.33	119.8	0.6
9	Panoma Gas Area	KS	Anadarko/Arkoma	1956	0.31	112.7	0.6
10	Green Canyon Blk 116	--	Fed. Offshore - Gulf of Mexico	1983	0.25	92.1	0.5
	Total	**--**	**--**	**--**	**8.06**	**2,951.0**	**15.3**

Note: Gas is wet after lease separation.
Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996* (December 1997).

Table 6. U.S. Natural Gas Productive Capacity Utilization and Surplus Deliverability by Region, 1990, 1995, and 1996

Region	Productive Capacity Utilization (percent as of January) 1990	1995	1996 (estimate)	Surplus Deliverability (percent as of January) 1990	1995	1996 (estimate)
Gulf Coast	79.5	81.1	83.3	23	18.7	13.8
Anadarko/Arkoma	72.3	80.5	88.7	28	19.5	11.3
Permian Basin	78.5	79.8	80.4	20	19.0	17.9
Rockies	81.5	81.1	85.8	19	18.9	14.2
East Texas	79.4	81.1	83.5	23	18.7	13.8
San Juan Basin	73.6	76.3	75.8	26	23.7	24.2
Offshore	78.5	75.9	70.4	22	24.1	29.6
Total Lower 48	**77.3**	**79.3**	**79.8**	**23**	**20.7**	**20.2**

Note: Utilization factors for the Gulf Coast, Permian Basin, and East Texas regions are average factors for the relevant States weighted by the relative dry gas production volumes in the region.
Source: Energy Information Administration, *Natural Gas Productive Capacity for the Lower 48 States* (December 1996).

Oklahoma. In October 1997, Mobil and Anadarko Petroleum Corp. announced that they would jointly exploit deeper horizons in Hugoton, providing further indication of future potential. Two other Anadarko/Arkoma gas fields rank among the top 10 in the lower 48. Panhandle West in Texas produced a daily average of 0.36 Bcf and the Panoma gas area in Kansas produced another 0.31 Bcf daily on average in 1996.

Contracting productive capacity reduced Anadarko/Arkoma's surplus deliverability from 28 percent in January 1990 to about 11 percent in January 1996 (Table 6). Output gains from infill drilling and some new finds at Hugoton, combined with a stabilization of productive capacity, should keep Anadarko/Arkoma's gas production level at about 8.1 Bcf per day (3.0 Tcf per year) through 2000 (Table 2).

Permian Basin

The Permian Basin region spans from eastern New Mexico to western Texas (Railroad Commission Districts 7B, 7C, 8, 8A, and 9). Gas production declined between 1990 and 1996, from 4.6 to 4.4 Bcf per day (1.7 to 1.6 Tcf per year), while proved reserves declined by about one-tenth to 14.1 Tcf in

1996 (Table 3). The top five fields—Gomez, Spraberry Trend Area, Puckett, Sugg Ranch, and Keystone—account for about one-quarter of total Permian Basin gas production and one-third of the region's proved reserves. AD gas accounts for about two-fifths of gas production and reserves in the Permian Basin and is almost as large in absolute terms (about 2 Bcf per day) as offshore AD gas output.

Improvements in both seismic technology and drilling methods could give the Permian Basin new life during the late 1990s. One play, Texas' Val Verde Basin, a sub-basin within the Permian, may have world-class potential. While Val Verde has yielded finds such as Puckett since the 1950s, improved seismology has shown huge, previously unknown structures in the Ellenburger formation and thrusted rocks extending further east and north in Val Verde than previously realized. Thrusted Shawn reservoirs, limestones that produce either from fractured intervals or reefs, are at 10,000 feet and offer more immediate economic opportunity than deeper plays. In addition, Wolfcamp (also known as Canyon Sand) is a low-risk, limited-potential play that is popular because of success rates of 90 percent in some cases.

The potential from these plays, combined with one of the highest surplus deliverability measures among producing regions (an estimated 18 percent in 1996), should help to raise Permian Basin gas production more than 10 percent between 1996 and 2000 to 5.2 Bcf per day (1.9 Tcf per year) (Table 2).

Rocky Mountain Area

The Rocky Mountain area, including Colorado, Utah, and Wyoming, was one of the fastest-growing U.S. producing regions between 1990 and 1996 and has the potential for further output gains through 2000. Gas production increased nearly two-thirds since 1990 from 2.5 Bcf per day (0.9 Tcf per year) to 4.1 Bcf per day (1.5 Tcf per year) in 1996 (Table 2). Major plays in the Rockies include the Wind River Basin, the Labarge and Big Piney Projects, the Overthrust Belt, the Green River Basin, and the Powder River Basin.

The Rocky Mountain area is one of the newest major gas producing regions in the United States in terms of average field age, with most of the leading fields dating from the 1960s or later. The top producing fields in 1996 included Wattenburg in Colorado (0.24 Bcf per day), Anschutz Ranch East in Utah/Wyoming (0.23 Bcf per day), Whitney Canyon-Carter Creek in Wyoming (0.22 Bcf per day), and Bruff in Wyoming (0.14 Bcf per day).[29]

A growing portion of Rockies' natural gas production during the early 1990s came from coalbed methane (Figure 4), spurred by a Federal tax credit for natural gas produced from coal seam wells with initial drilling prior to January 1, 1993. This tax credit extends up to 10 years for any producing well so it will affect production on at least some portion of coalbed production through 2002. Expiration of the qualifying period for the tax credit has reduced drilling activities, which will likely affect the future volume of coalbed methane production in both the Rockies and San Juan Basin, another region which is the leading U.S. producer of coalbed methane. The Rocky Mountain area is also a significant producer of AD gas, which accounted for 12 to 15 percent of total regional output in the mid-1990s and about one-tenth of reserves.

Proved gas reserves in the Rocky Mountain area grew by one-third from 16.0 trillion cubic feet (Tcf) in 1990 to 21.7 Tcf in 1996 (Table 3). Large recent reserve gains at the Big Piney-LaBarge Field have made it the largest field in terms of reserves in Wyoming, while further reserve increases are also likely to come from the Madden Field and Moxa Arch Extension. The Madden Field could become a very profitable play because it might be possible to draw most of its gas out of the formation through just one or two holes drilled at the top of the reservoirs. The Moxa Arch Extension ranks high in terms of gas produced per drilling dollar, but this does not include heavy associated costs of fracturing the tight formations that are common to this play. Other possible sources of increased gas in the near term include coalbed methane in the Powder River play of Wyoming, where productive capacity rose from near zero in 1990 to 28 million cubic feet per day in 1996, with at least another 35 million cubic feet per day waiting for connection and pipeline hookup.

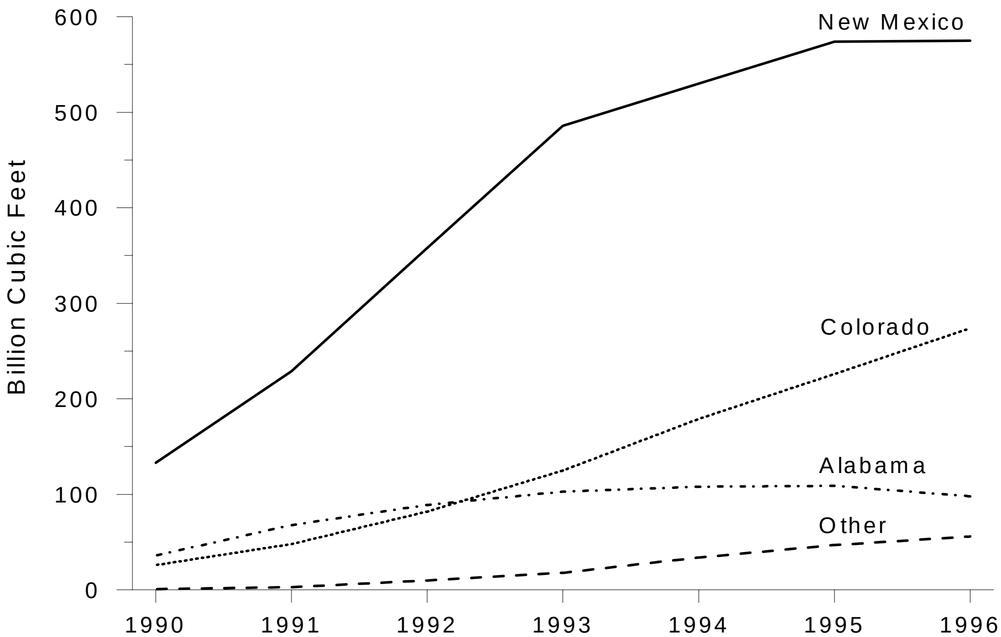
As a result of reserve growth, the 1996 reserve-to-production ratio in the Rocky Mountain area was among the highest in the lower 48 States at 14 (Table 3). Large reserves and output from new finds are expected to contribute to an 11-percent growth in Rockies' gas production between 1996 and 2000 to around 4.6 Bcf per day (1.7 Tcf per year) in the latter year (Table 2). The rate of growth in Rockies' gas output during the latter half of the 1990s is quite impressive given the number of impeding factors. Such factors include the phase-out of the coalbed methane tax credit, saturation of Western markets, and the cost of building additional pipeline capacity to redirect more Rockies' gas eastward towards high-demand markets, rather than due to any shortage of gas supplies.

East Texas

The East Texas region includes Northeast Texas (Railroad Commission Districts 5 and 6) and northern Louisiana. Its gas

[29]Energy Information Administration *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report 1996* (Washington, DC, December 1997), p. 58.

Figure 4. U.S. Coalbed Methane Output, 1990-1996



Note: Other includes Kansas, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming.
Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996* (December 1997).

production increased by one-tenth from 3.0 Bcf per day (1.1 Tcf per year) in 1990 to 3.2 Bcf per day (1.2 Tcf per year) in 1996 (Table 2). Nearly one-half of production and over one-half of reserves in East Texas are accounted for by five fields: Carthage, Oak Hill, Willow Springs, Whelan, and Hawkins. Carthage is the largest among them; in 1996, it produced 203.5 Bcf (wet gas, 0.56 Bcf per day) and was the fifth largest U.S. gas field that year in terms of production.

East Texas is one of the few onshore regions to register substantial new field finds in recent years. Drilling in the Cotton Valley lime reef play resulted in 25 discoveries reported out of 45 wells as of mid-1997 for a 55-percent success rate. At least 550 Bcf of reserves have been found at the Cotton Valley Lime reef play, helping to expand the region's reserves 7 percent to 11.1 Tcf in 1996 after little change between 1990 and 1995. Overall, East Texas gas output is likely to increase moderately by about 0.1 Bcf per day to just under 1.2 Tcf per year in 2000.

San Juan Basin

The San Juan Basin in northwestern New Mexico, like the Rockies, has substantially increased production since the late 1980s. Production almost doubled between 1990 and 1996 to 2.7 Bcf per day (1.0 Tcf per year) in 1996 (Table 2) and is mainly accounted for by two giant gas fields—Basin and Blanco—that are two of the three largest in the lower 48 States. The Basin Field, first drilled in 1947, was formed in February 1961 by combining several existing fields. The Blanco Field encompasses much of the central San Juan Basin.

Much of the increase in gas production in the San Juan Basin during the 1990s has come from coalbed methane wells. Production gains were strongest until the end of 1992, when phase-out of the coalbed methane tax credit began. Coalbed methane production grew further in the years 1993 through 1996, owing to subsequent completion of wells spudded prior to the tax credit deadline and as these wells proceeded through the dewatering phase early in their production cycle. San Juan Basin production increases were also the result of well recompletions in the basin's deeper tight sands formations as operators employed new technologies to increase gas flow.

Expiration of the coalbed methane tax credit had an immediate impact on San Juan Basin proved reserves, which contracted 13 percent between 1992 and 1996 (in part because of downward revisions as some coalbed fields were considered no longer economical, especially in a pipeline constrained market) after expanding by a similar percentage between 1990 and 1992. This left the region's reserves at

13.7 trillion cubic feet in 1996, compared with 14.0 in 1990. Stagnant reserves are not likely to limit the San Juan Basin's gas production in the near term, because its reserves still represent almost 14 years' worth of production (well above the U.S. average). Gas output is projected to increase about 3 percent per year on average during the late 1990s to 3.0 Bcf per day (1.1 Tcf per year) in 2000 as a result of reduced coalbed methane activity, well below its double-digit annual growth rate during the early 1990s.

As with the Rockies region, the major constraints on future growth of gas production in the San Juan Basin are more related to market conditions and infrastructure than to physical output capability. With peak productive capacity utilization in the San Juan Basin running below 80 percent in the mid-1990s, surplus deliverability was the highest of any major gas-producing basin at over 20 percent. Thus, a major determinant of future gas output here is likely to be the pace of expansion of pipeline capacity to carry the gas to major markets in the Northeast and Midwest given the saturation of California and other Western markets.

Appalachian Basin

The Appalachian Basin extends from the Middle Atlantic to the South Atlantic Census Bureau divisions and is the largest gas-producing basin close to major markets in the Northeast. This region is a minor producer of gas, providing only about 2 percent of total lower 48 gas supplies, but it is a major source of gas for the large urban areas of the Northeast. Pennsylvania and West Virginia account for the majority of the Appalachian Basin's natural gas production, while Virginia has increased production following sizable new finds, including coalbed methane deposits.

A portion of the region's 1.4 Bcf per day gas output comes from unconventional sources, such as Devonian Shale. In December 1992, the National Petroleum Council estimated that the Devonian Shale in this area contains about 27 Tcf that could be produced using known technology.[30] This compares with proved reserves in 1996 of 7.7 Tcf, which is one-third larger than the 1990 level mainly because of the new finds in Virginia.

Higher reserves raised the Appalachian region's ratio of proved reserves to production to 15 in 1996, the highest in the lower 48. Such a ratio indicates high likelihood of production increases during the late 1990s, with Appalachian Basin gas output forecast to grow about 16 percent to 1.6 Bcf per day (0.6 Tcf per year) in 2000. With demand in the Northeast expected to far exceed the expected modest increment to Appalachian Basin production during the 1997 through 2000 period, attractive opportunities are likely for gas suppliers from other regions of the lower 48 and from Canada.

Canadian Supplies

Sharp increases in natural gas imports from Canada have made Canada the third most important source of U.S. gas supplies after the offshore and Gulf Coast regions. Various factors have contributed to the strong growth in U.S. natural gas imports from Canada over the past decade,[31] including:

- The 1985 Agreement on Natural Gas Markets and Prices that changed Canada's pricing policy from government-administered to market-oriented pricing

- The "market-based procedure" for determining the surplus Canadian natural gas available for export that replaced the previous reserves-to-production (R/P) ratio procedure in 1987

- The U.S.-Canadian Free Trade Agreement (CFTA) of 1988 that prohibited most trade restrictions on energy products.

Since 1987, U.S. gas imports from Canada have nearly tripled to around 8 Bcf per day (2.9 Tcf per year) in 1996, accounting for 13.5 percent of U.S. gas supplies. Growth was swiftest between 1990 and 1995, when imports of Canadian gas increased at a 14-percent average annual rate. Relative price movements helped to stimulate increased U.S. gas imports from Canada, since the average wellhead price in the lower 48 changed from being 11 percent cheaper than imported Canadian gas in 1990 to being 11 percent more expensive by 1996 (Figure 5).

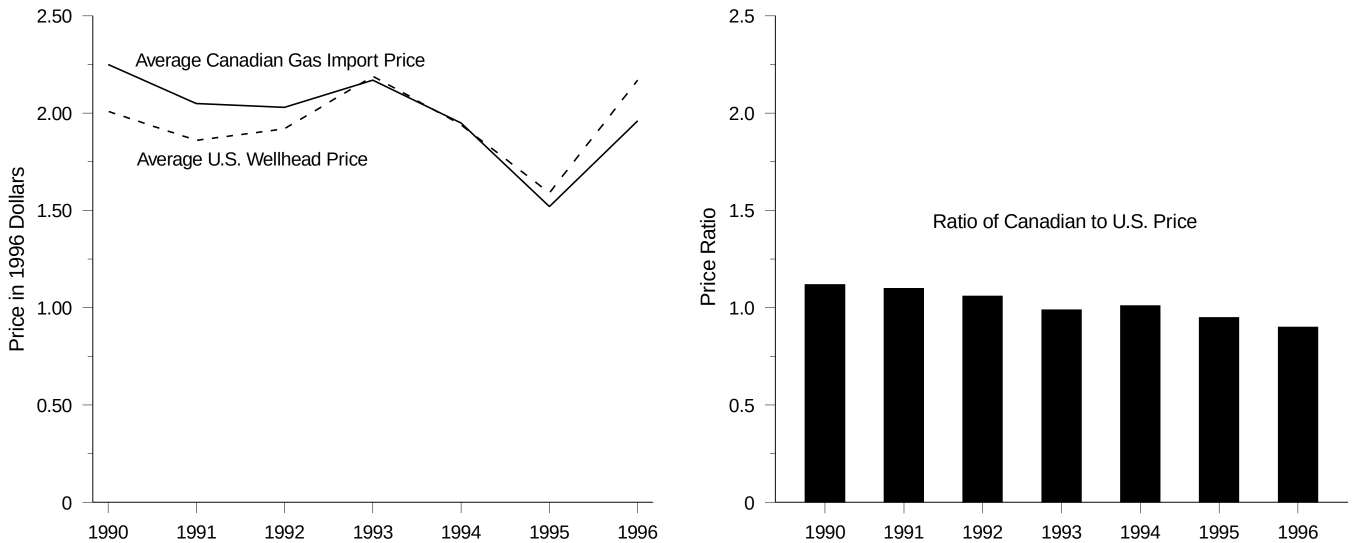
Canada produced about 5.6 Tcf of gas in 1996, equivalent to about 30 percent of lower 48 production. Canadian gas production is centered in the Western Canada sedimentary basin, 95 percent of which occurs in the western provinces of Alberta (83) and British Columbia (12). Total Canadian gas production was 56 percent higher in 1996 than in 1990, while natural gas end-use consumption in Canada grew by only 23 percent during the same period.[32] As a result, domestic use of natural gas in Canada (47 percent of final gas sales occurs

[30]National Petroleum Council, *The Potential for Natural Gas in the United States: Source and Supply* (1992), p. 111.

[31]For more detail see Energy Information Administration, *Natural Gas 1996 Issues and Trends*, DOE/EIA-0560(96) (Washington, DC, December 1996), p. 95.

[32]Canadian Association of Petroleum Producers, *CAPP 1996 Statistical Handbook* (Calgary, Alberta, Canada, 1997), Tables 3.10a, 6.3a, and 9.1a.

Figure 5. Comparison of Average U.S. Natural Gas Wellhead Price and Canadian Natural Gas import Price, 1990-1996



Note: Prices in 1996 dollars based on appropriate gross domestic product (GDP) deflators as published in the *Survey of Current Business* (August 1997) and distributed on the Internet site www.bea.doc.gov.

Source: Energy Information Administration (EIA), *Natural Gas Annual* (September 1997).

in the eastern provinces of Ontario and Quebec) fell from representing 60 percent of Canadian production in 1990 to only 49 percent in 1996. Since 1990, the TransCanada Pipeline system has substantially increased its capability to move supplies from the Alberta/Saskatchewan border (currently 7.2 Bcf per day during the winter) but not rapidly enough to meet both the growth in domestic demand and export capacity. As a result, TransCanada Pipeline and several other firms have developed plans to expand domestic and export capability over the next several years to meet the demands of Western producers and customers in Canadian Eastern markets.

While the more than 50-percent growth in Canadian gas production reduced the country's reserves-to-production ratio from almost 26 in 1990 to 12 in 1996, the Canadian Gas Potential Committee has estimated remaining marketable gas, including discovered reserves and undiscovered potential in established exploration plays and coalbed methane, at about 570 trillion cubic feet.[33] This suggests that Canadian supplies are more than sufficient to meet expected domestic and export demands well past the year 2000. New gas finds off Canada's Atlantic shores are expected to begin commercial production by late 1999 and contribute significantly to North American gas supplies in the longer term, although their impact on U.S. markets through 2000 will be limited.

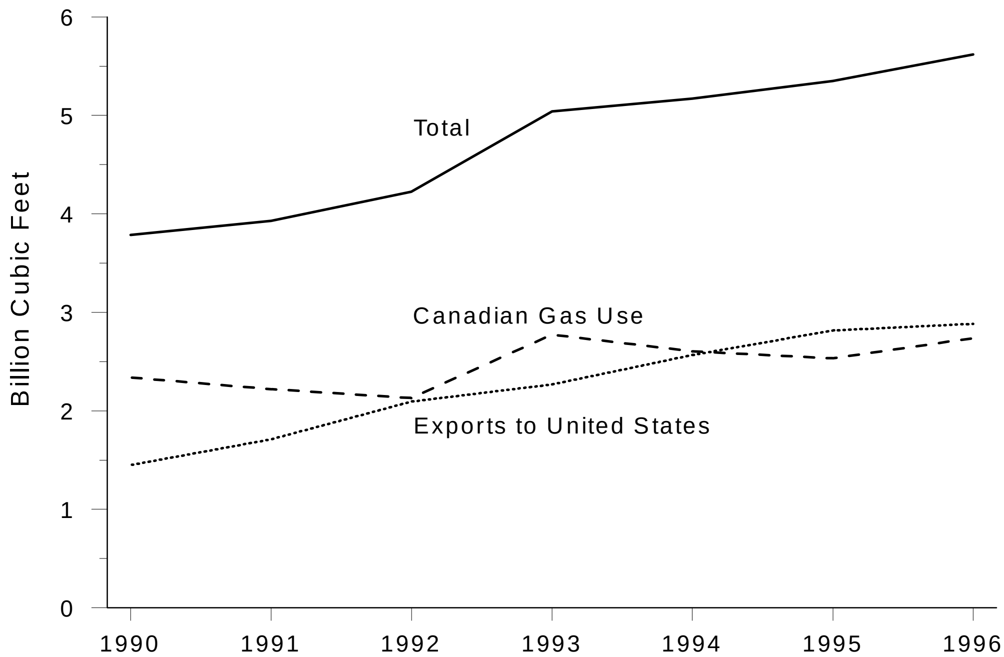
The rising importance of U.S. export markets to Canadian gas producers is illustrated by the fact that more than half of Canadian gas production by the mid-1990s was destined for export to the United States compared with two-fifths in 1990 (Figure 6). In 1996, growth in Canadian gas exports to the United States slowed to 2.4 percent primarily because of bottlenecks resulting from existing pipeline capacity constraints. Relative price data show that prices for U.S. imports of Canadian gas in 1996 continued to decline relative to the average wellhead price in the lower 48. The downward movement in the price for Canadian gas relative to the U.S. price was influenced also by a significant shift in the exchange rate, with the Canadian dollar falling from $0.86US in 1990 to $0.73US in 1996.[34] Favorable price trends combined with continued demand growth in the lower 48 are likely to raise imports of Canadian gas by over one-third between 1996 and 2000 to about 10.7 Bcf per day (3.9 Tcf per year) in 2000.[35]

[33]"Where future Canadian gas supply will originate," *Oil and Gas Journal* (December 15, 1997), p. 67.

[34]Canadian Association of Petroleum Producers, *CAPP 1996 Statistical Handbook* (Calgary, Alberta, Canada, 1997), Table 5.5c.

[35]See Energy Information Administration, *Annual Energy Outlook 1998* (December 1997), p. 118.

Figure 6. Canadian Gas Exports to the United States and Total Canadian Gas Production, 1990-1996



Note: Canadian gas use was calculated by subtracting exports to the United States from total Canadian gas production.

Sources: **Canadian Gas Exports to United States:** Energy Information Administration, *Natural Gas Annual 1996* (September 1997) and earlier editions. **Canadian Gas Production:** Canadian Association of Petroleum Producers (CAPP), *Statistical Handbook 1996* (September 1997).

Receipt Capabilities

Wellhead gas productive capacity is only one of the elements necessary to meet U.S. natural gas demand. Because major market areas are not usually located in close proximity to supply/production areas, moving the gas from the wellhead to market areas via pipeline is an important element of satisfying demand. The first leg of the transportation journey, which is relevant to this chapter, requires adequate pipeline receipt capability to facilitate the movement of the natural gas from producing fields to the interstate pipeline system.

In the United States, natural gas typically moves from major supply areas in Texas, Oklahoma, Louisiana, Wyoming, Kansas, Colorado, New Mexico and the Offshore Gulf of Mexico to the North and East. These routes saw a rise in average daily usage rates between 1990 and 1996, while usage rates fell sharply on pipelines heading westward into markets on the Pacific Coast, which are saturated with gas from Canada. Additionally, the dramatic increase in gas imports from Canada during the past decade has opened up new supply routes from Western Canada to the lower 48, with the swiftest growth in route volume occurring into the Northeast.

While wellhead gas productive capacity and import capacity were sufficient to meet U.S. demand under normal weather conditions through the end of 1997, unusually high peak-day or peak-week heating or cooling demand required deliveries from storage or peak-day shaving. Limited pipeline receipt capabilities in key production areas, such as the Gulf of Mexico, the Northern Rocky Mountains, and the San Juan Basin, compromise the ability to meet peak demand. And with total U.S. gas supplies expected to increase by more than 12 percent between 1996 and 2000, the additional 7 Bcf per day of supplies will require expansion of existing transport and storage capacity. Several projects have been proposed that will expand the receipt capability of the interstate pipelines transporting natural gas from producing to consuming areas in the United States, including gas imports via pipeline from Canada.

Offshore and Onshore Gulf Northward

The offshore and onshore Gulf region, which together provide almost half of all natural gas produced in the lower 48, supply a large portion of this gas to other regions. These two regions account for a large portion of the 12.6 Bcf per day on average transported from the Southeast to the Midwest and Northeast, where rising shipments brought average usage rates to 82 to 86 percent in 1996.

Despite an already well-developed gas infrastructure around the Gulf, the last 6 years have seen an ongoing effort to build sufficient offshore pipeline receipt capacity to support the rapidly increasing wellhead productive capacity, particularly offshore. Offshore pipeline construction increased more than 20 percent between 1990 and 1995, followed by completion of two large expansion projects in 1996—the Shell Gas Pipeline and the Centana Main Pass/Viosca Knoll Gathering System. Several new pipeline projects were completed in 1997, including the Garden Banks Offshore System, the Manta Ray Gathering System, the DIGS Main Pass Gathering System, the Discovery Pipeline, and the Nautilus Pipeline.

As a result of this construction, nearly 20 Bcf per day of pipeline capacity extends onshore from the offshore Gulf region, mostly to Louisiana. Major pipelines that receive onshore and offshore Gulf gas for transportation to markets in the Northeast and Midwest include ANR, Columbia Gulf, Florida Gas, Koch Gateway, Southern Natural Gas, Tennessee Gas, Texas Eastern, Transcontinental, and Trunkline systems. Some of these pipeline systems, notably Tennessee and Texas Eastern, are very large and were operating at nearly full capacity in 1996 during peak periods.

Despite ambitious pipeline expansion plans to bring an additional 3 Bcf per day or more of offshore gas ashore at Alabama, Louisiana, and Mississippi by the year 2000, lack of adequate capacity to transport the gas to markets in the Northeast and Midwest could hamper future gas deliverability from the Gulf. There are 10 proposed projects that would bring more than 1.6 Bcf per day of additional gas ashore at Louisiana and about 1.5 Bcf per day at Mississippi and Alabama (see Appendix B, Table B2). Potential bottlenecks may arise further downstream as existing pipeline capacity into Mississippi and Arkansas is not expected to expand by similar magnitude and could face average usage levels far in excess of 90 percent.

An alternative solution, increased reliance on storage, could allow for increased gas deliveries from the Gulf to the Northeast without adding new pipeline capacity. A number of new storage facilities, including high-deliverability salt cavern storage, are being built both in the Northeast near the consuming markets and on the Gulf coast near offshore production areas.[36] New salt cavern storage facilities expected to be built during the years 1998 through 2000 could add up to 1.5 Bcf of daily deliverability from storage in the Southwest and up to 1 Bcf per day from storage in the Northeast (mainly in New York and Pennsylvania). By moving the gas into markets such as the Northeast during nonpeak periods, natural gas marketers are better able to utilize existing pipelines. Because storage is generally cheaper to build than laying new pipeline, this is an economically attractive option for the short term. In the longer term, however, marginal increases from greater usage of existing pipelines may not be sufficient to accommodate the expected magnitude of produced gas in certain regions.

From the Rockies and San Juan Basin Eastward

Despite strong growth in production and reserves in the Rocky Mountain area and in the San Juan Basin of New Mexico between 1990 and 1996, only a small portion of that production saw its way to Midwest or Northeast markets. Pipeline capability to move gas eastward from that area has been limited as traditionally the production has been targeted to Western markets. But with Western markets becoming saturated, interest has increased in moving supplies eastward.

While the northern Rocky Mountain area has not experienced receipt constraints for supplies moving westward, it has been unable to gain access to Eastern markets because of limited pipeline receipt capability. This constraint is expected to ease as eastern access via the San Juan Basin has increased and several expansion projects have been planned that will increase pipeline capacity from the Rocky Mountains to hubs serving the Midwest and East. Expansions completed in 1997 included KN Energy's Pony Express line from Wyoming to several long-haul pipelines running from the Permian Basin to the Midwest and expanded capacity from the Overthrust and Green River basins to the eastward-running Trailblazer Line.

Sufficient new pipeline capacity is planned between 1998 and 2000 to accommodate the expected production increases in the Rockies and San Juan Basin areas (almost 0.8 Bcf per day additional) without major bottlenecks. According to 1996 data, the El Paso pipeline from the San Juan Basin of New Mexico into Texas alone had nearly 1 Bcf per day of unused capacity on average. Along with completion of the TransColorado line (0.3 Bcf per day) to the San Juan Basin running from Colorado's Piceance Basin, Southwestern Wyoming, and Utah's Paradox and Uinta basins, this suggests adequate receipt capability for the anticipated increase in San Juan Basin output during the next 3 years. The Natural Gas Pipeline Company of America's Amarillo expansion would help move these new supplies to the East through Chicago from the Waha hub in Texas.

[36]Energy Information Administration, "U.S. Underground Storage of Natural Gas in 1997," *Natural Gas Monthly*, DOE/EIA-0130(97/09) (Washington, DC, September 1997).

Technological Improvements

A decade of technological improvements has reduced finding costs, raised the size of finds, and opened new areas of exploration

The combined application of several new technologies over the last decade has contributed to U.S. gas production gains during the 1990s in a number of ways. These technologies include enhancements to exploratory and developmental activities, such as 3-D seismic and cross-well seismic surveys, improved drilling techniques through the use of horizontal and multi-lateral drilling, and new offshore production systems that include floating and subsea assemblies.

Lower finding costs facilitated by wider use of 3-D seismic surveys and other new technologies have reduced production costs and contributed to higher U.S. gas production during the 1990s.* Over the past decade, onshore finding costs have been cut by more than half, while offshore finding costs have fallen even more sharply. As a result, offshore finding costs converged with onshore finding costs in the mid-1990s after more than a decade of exceeding them by a considerable margin (Figure 7). The nearly two-thirds reduction of offshore finding costs between 1986 and 1996 was a major factor in the increased profitability of offshore gas production because offshore lifting costs are much lower and comprise a smaller share of total production costs than with onshore production (Figure 8).

New technologies have redefined deep water drilling opportunities in the Gulf of Mexico. In 1996, dry gas productive capacity in the Federal Offshore Gulf of Mexico region was nearly 30 percent of the productive capacity for the lower 48 States. The offshore region also had a higher average reserves addition per successful well, averaging more than 16 Bcf from 1992 through 1994. The importance of the offshore portion of total U.S. gas production is expected to rise further through the year 2000 with new capacity due for startup from deep water and subsalt wells as well as continued gains in AD gas output. Because of technological changes, deep water drilling is now taking place at previously impossible water depths—for example, Shell's Mensa at depths of more than 5,300 feet. Future plans call for even deeper drilling, with Shell's Couloumb and BAHA projects planned at 7,500 feet or more (Figure 9).

The technologies contributing to these breakthroughs include:

- **3-D Seismic Surveys** - 3D seismic surveys are conducted by use of meticulously spaced vibration-detecting geophones to measure the feedback from a sequence of experimental seismic disturbances. Their use has greatly improved geological interpretations and has led to a much higher rate of successful wildcat drilling. Future innovation may include 4D seismic (essentially time-lapse 3D seismic), which could help improve flow models to optimize recovery.

- **Cross-well Seismic Surveys -** Cross-well seismic surveys are used to evaluate the geological characteristics of terrain between wells. Cross-well seismic measures the vibrations detected in one or more wells when wide-spectrum sound is produced at varying intensity in another well. The nature of the vibrations provides important information on the qualities of the intervening region.

- **Horizontal Drilling** - Originally employed onshore in the 1980s, horizontal drilling angles off the vertical to follow the path of a gas-producing formation. While more costly than vertically completed wells, wells with horizontal completion segments often produce at rates 3 to 5 times that of vertical wells and may reduce the unit costs of production by as much as 50 percent. The first offshore horizontal wells were drilled in 1990 and have played an important role in exploiting gas reserves in the Gulf of Mexico.

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*The finding and lifting costs introduced here represent calculations for the major integrated oil- and gas-producing companies and the large independent firms included in the Energy Information Administration's Financial Reporting System (FRS). The FRS companies are 24 major U.S. energy companies that are required to report financial and operating developments annually to the Energy Information Administration on Form EIA-28, "Financial Reporting System," pursuant to Section 205(h) of the Department of Energy Organization Act.

Technological Improvements (Continued)

- **Multilateral Drilling -** This drilling method involves drilling multiple horizontal well completion segments at different depths having varying characteristics (e.g., permeability) and allows for economical recovery of a greater portion of a given well's reserves under certain conditions.

- **Subsalt Drilling** - Considerable gas deposits are believed to reside beneath large horizontal sheets of salt. While historically the salt sheets blurred seismic images and made it difficult to drill successfully for subsalt gas deposits, new technologies have sharpened seismic images and improved chances of discovery. The first subsalt discovery to be commercially developed was the 1993 Mahogany strike in 370 feet of water off the Louisiana coast. Subsequent discoveries, including the Teak, Agate, Chimichanga, Enchilada, and Gemini wells, suggest high future potential for offshore development of subsalt gas deposits.

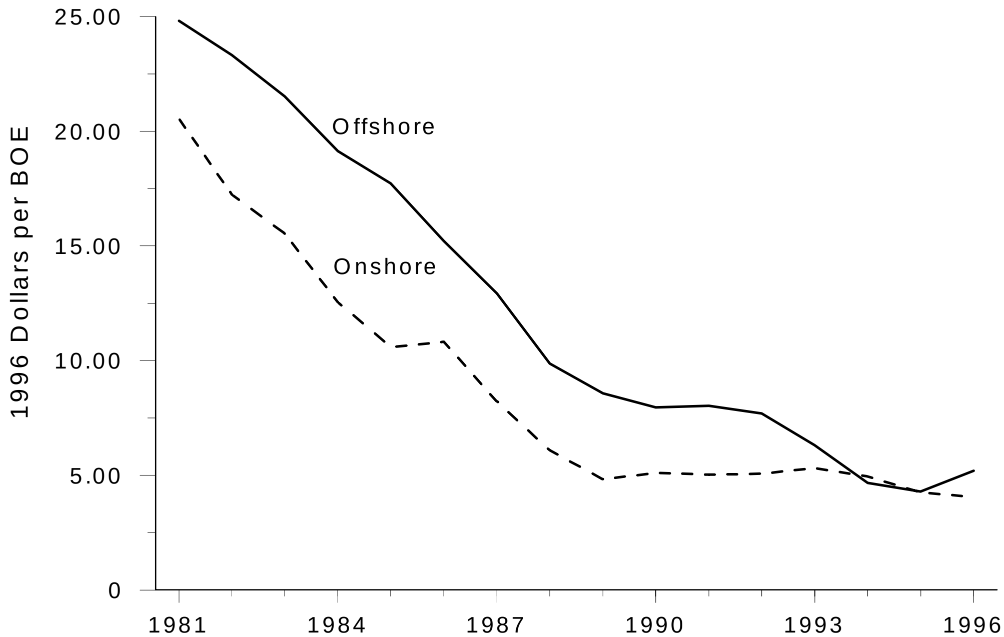
- **Floating Production Systems -** Key to expansion of deep water gas exploration and development, floating production systems include floating platforms or structures tethered to the sea floor. Their advantages over fixed platforms include deeper range in offshore waters, lower average costs over their productive lives because they can be towed to various locations, and greater tolerance of hurricanes and other inclement weather as they move compliantly to waves. Two major types of floating systems are:

  — **Tension Leg Platform (TLP)** - Consisting of a hull with excess buoyancy that maintains tension in a tether mooring system, it behaves like an inverted pendulum that moves compliantly to waves. Because conventional TLPs have encountered problems in waters over 3,000 feet, various modifications have been created for deeper waters that include tension base TLPs, suspended TLPs, tension raft jackets (TRJs), and hybrid compliant platforms (HCPs). The first TLP, Conoco's Jolliet at 1,720 feet of depth, came onstream in 1989.

  — **Spar Production System** - Consisting of a single point buoy tanker loading and mooring platform with a storage tank, the spar's stability is increased because its center of buoyancy is above its center of gravity. In contrast to a TLP, the spar's hull does not support the production risers; instead, two separate floats carry the weight of the risers. Spar technology offers operators a way to reduce deep water production costs while still having surface well completions. The first spar was introduced in 1997 at Oryx's Neptune in nearly 2,000 feet of Gulf water.

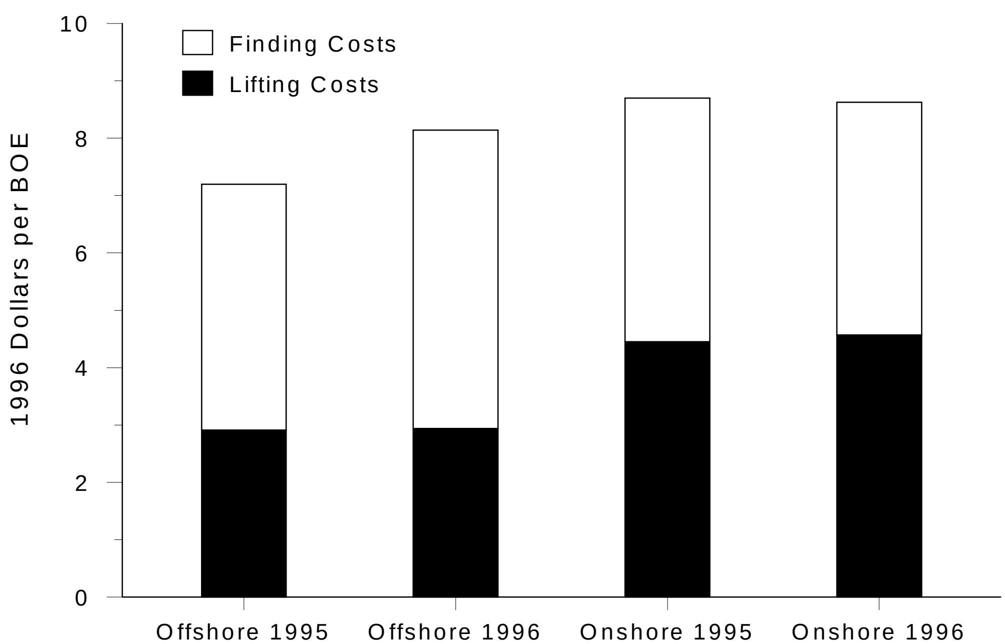
- **Subsea Production Systems -** Subsea production systems have found wider applications in the Gulf of Mexico over the past 2 to 3 years as production moves into deeper water. By tying back subsea wells to either floating production systems or platforms in shallower water, operators are able to develop wells, including smaller ones, that otherwise would not be economic. In deeper waters, some operators are using subsea production systems based on template and well cluster designs. The Gulf's first subsea cluster production system was installed at Popeye Field, which started production in 1996. In an attempt to reduce costs, subsea production systems are becoming smaller, more modular units, and greater emphasis is being placed on retrievable subsea components.

Figure 7. Finding Costs for Natural Gas and Crude Oil, 1981-1996



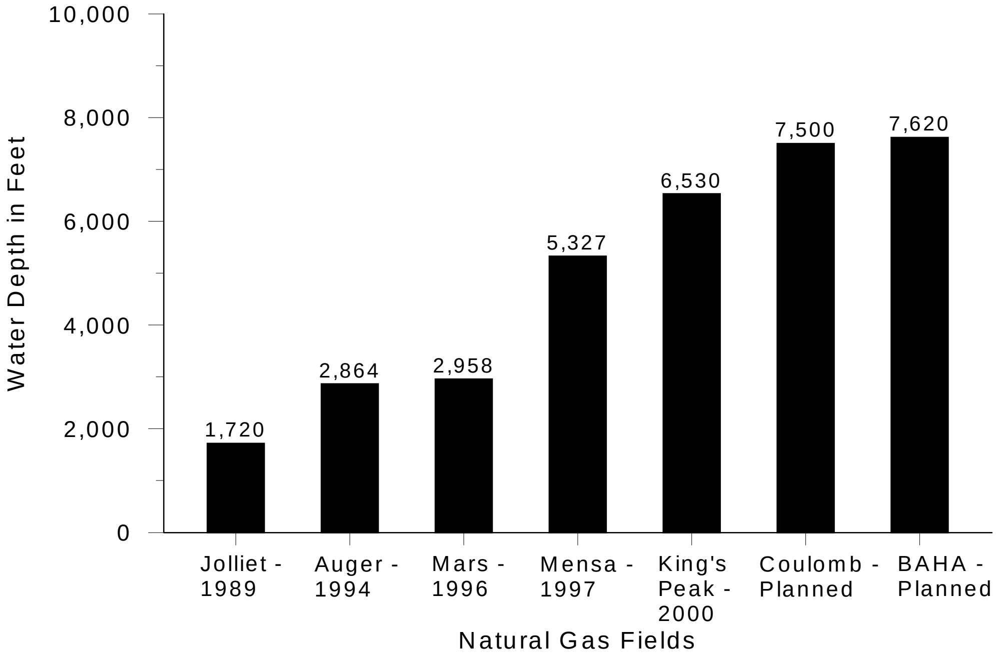
BOE = Barrels of oil equivalent.
Note: Finding costs are 3-year weighted averages of exploration and development expenditures for oil and gas, converted to BOE.
Source: Energy Information Administration, *Performance Profiles of Major Energy Producers 1996* (January 1998) and earlier editions.

Figure 8. Offshore and Onshore Production Costs for Natural Gas and Crude Oil, 1995 and 1996



BOE = Barrels of oil equivalent.
Note: Finding costs are 3-year weighted averages of exploration and development expenditures for oil and gas, converted to BOE. Lifting (or production) costs are the out-of-pocket costs of extracting oil and gas and include operating (direct lifting) costs and production taxes.
Source: Energy Information Administration, *Performance Profiles of Major Energy Producers 1996* (January 1998).

Figure 9. Depth Records in Deep Water Gulf Drilling



Note: Water depths (in feet) are noted for each project.
Source: "Seventy U.S. Gulf deepwater fields awaiting development, 26 are in production," *Offshore* (September 1997), p. 39.

Canada Southward

Canadian gas is imported into four U.S. regions: the Midwest (with a 28-percent share of the total in 1996); the Central States (17 percent);[37] Northeast (20 percent); and the Pacific Northwest (35 percent). Expansion of Canadian pipeline capacity has not kept up with the rapid U.S. demand growth for Canadian gas, raising the average usage rate on pipelines transporting this gas to the United States from 77 percent in 1990 to 84 percent in 1996. Certain corridors, especially from Canada to the U.S. Northeast and from Canada to the U.S. Midwest, were operating at or close to full operational capacity in 1996 (see Chapter 3), suggesting that Canadian gas imports may be close to maximum flow until additional capacity can be added.

The small growth in U.S. gas imports from Canada in 1996 and 1997 (less than 1 percent) was due largely to deliverability limitations to the TransCanada system and other exporting systems rather than because of Canadian supply limitations. Production capabilities in Western Canada, especially in Alberta, exceed the amount of pipeline capacity now existing on the system in that area (about 10.6 Bcf per day, of which 7.1 Bcf is directed toward Eastern Canada and the U.S. Midwest and Northeast). As a result, Canadian shippers have been unable to reach their full potential market to the east.

Proposals to alleviate the situation consist of at least 11 projects within Canada, which would provide an additional 0.3 Bcf per day to Canadian markets and 7.7 Bcf per day to U.S. gas import capacity from Canada from 1998 through 2000. (About 4.5 Bcf per day of import capacity was added from 1990 through 1997.) A number of these projects are competing for the same markets and will not be built in all likelihood. Even if only half of the proposed capacity is completed by 2000 (see Appendix B), it would accommodate the additional 2.8 Bcf per day of projected imports while easing bottlenecks on the pipeline network.

Moreover, on December 30, 1997, the Canada-Nova Scotia Offshore Petroleum Board approved the Sable Offshore Energy project, which is aimed at development of six gas fields containing an estimated 3 trillion cubic feet of gas. In light of these events, sales of Sable Island gas in U.S. markets appear likely before 2000, but they are unlikely to be large enough to affect gas deliverability to the lower 48 States appreciably during this period. The Maritimes & Northeast Pipeline (MNE) transportation project will bring gas from the

[37]Most of the gas imported into the Central Region goes to the Midwest.

Nova Scotian shelf offshore Sable Island to Eastern Canada and the United States. One other transportation project, the Marine Line Subsea proposal, continues to be considered as a possible alternative to move this gas to Canadian and U.S. markets.

Implications for Downstream Markets

Expanded pipeline capacity should move more gas eastward from the Rocky Mountain area and San Juan Basin of New Mexico to markets in the Northeast and Midwest during the next few years, although increased demand from within the Central Region could absorb some of the additional gas supplies from these two producing areas (see Chapter 4). Even larger increases in supplies are anticipated from Canadian gas imports moving southward and eastward and from Gulf supplies moving northward primarily towards the Northeast and Midwest. Oversupply of the Midwest market is possible, given the large capacity increases planned from all three sources, while increased supplies to the Northeast should help mitigate potential increases in natural gas prices. Increased use of storage, particularly high-deliverability salt cavern storage, is likely to play a role in stabilizing prices by better matching seasonal demand with available gas supplies. In the longer term, increased gas supplies from Nova Scotia are targeted primarily at the Northeast and Eastern Canada, potentially contributing to further leveling of natural gas prices throughout North America.

Summary

Natural gas production in the lower 48 States is forecast to rise 7.8 percent from an average of 50.1 billion cubic feet per day in 1996 to 54.0 billion cubic feet per day in 2000, with much of the increase coming from the offshore Gulf of Mexico, the Permian Basin, and the Rocky Mountain area. A technological revolution during the 1990s, led by 3-D seismic surveys, horizontal drilling, and new offshore platform designs, has opened up deeper water frontiers in the Gulf of Mexico while also yielding new opportunities in onshore producing regions. Additional pipeline capacity from producing areas in Western Canada to major markets in the U.S. Northeast and Midwest will allow natural gas imports from Canada to rise, contributing to increased U.S. gas supplies in the near term.

Planned pipeline expansions through 2000 appear generally adequate to accommodate new lower 48 productive capacity and increased Canadian gas imports, although bottlenecks may be caused by lack of sufficient capacity to carry anticipated new offshore gas production beyond onshore Louisiana and the fact that most of the pipeline expansions allowing for increased Canadian imports are not due for completion before 1999 and 2000.

Major expansions of underground storage underway in the Northeast and Midwest as well as along the Texas and Louisiana coasts could help to avoid bottlenecks for gas moving northward from the offshore and onshore Gulf and ensure adequate deliverability to the top U.S. gas markets.