NATURAL GAS SUPPLY ASSOCIATION SURVEY:

NATURAL GAS FIELD DELIVERIES
&
PRODUCTIVE CAPACITY
AS OF JANUARY 1, 1997

Natural Gas Supply Association
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NATURAL GAS SUPPLY ASSOCIATION SURVEY: NATURAL GAS FIELD DELIVERIES & PRODUCTIVE CAPACITY AS OF JANUARY 1, 1997

EXECUTIVE SUMMARY

The 1997 Natural Gas Supply Association (NGSA) natural gas field deliveries and productive capacity survey reveals the following trends for the 103 gas producer respondents. These 103 producers were responsible for 60 percent of the 1995 lower-48 natural gas production.

- Natural gas field capacity utilization levels of the 103 respondents increased on an annual basis, going from 94.1 percent in 1995 to 95.0 percent in 1996. In comparison, the estimated annual maximum feasible capacity utilization level was reported to be 96.5 percent.

- During 1996, the respondents reported a 3.9 percent increase in annual field deliveries and a 2.9 percent increase in their ability to inject natural gas into the nation's gas transmission system. The larger increase in annual gas deliveries was responsible for the 0.9 percentage point increase in annual capacity utilization.

- In the three prior surveys, the annual maximum feasible capacity level was reported to be between 93.9 and 94.6 percent. This year's survey reports about a two (2) percentage point increase in the maximum feasible capacity factor to a level of 96.5 percent. This increase indicates that gas producers can operate their gas field capacity closer to its full potential.

- Three survey regions reported a significant increase in annual capacity utilization: the Offshore Gulf (+2.8 percentage points), the Rocky Mountain/Pacific region (+1.3 percentage points), and the San Juan Basin (+1.2 percentage points). Because the Offshore Gulf region accounts for about one-third of the gas deliveries reported in the survey, the large increase in Offshore Gulf capacity utilization is largely responsible for the increase in utilization reported for the entire U.S. lower-48. Two other survey regions -- the Permian and Anadarko basins -- posted negligible increases in annual capacity utilization, amounting to 0.6 and 0.5 percentage points, respectively.

- Only two regions posted significant declines in annual capacity utilization: the East/North Central region (-3.3 percentage points) and the Onshore Gulf region (-1.5 percentage points). The decline in Onshore Gulf capacity utilization is noteworthy because this decline is due to a 6.5 percent increase in Onshore Gulf productive capacity which more than offsets the 4.8 percent increase in gas field deliveries.

- The 6.5 percent increase in Onshore Gulf productive capacity equals a 479 MMcf/day volumetric increase, which is over half of the aggregate increase in productive capacity reported for 1996. Thus, the notion that the Onshore Gulf is a "mature" gas geologic province with diminishing prospects for exploration and development is questionable in light of these survey results.

- Just as 1996 annual capacity utilization increased, so too did December capacity utilization. Lower-48 1996 December capacity utilization level of 98.3 percent was 0.7 percentage points higher than December 1995 utilization. Both December 1995 and 1996 capacity utilization exceeded the reported maximum feasible capacity level of 96.7 percent, indicating that the gas production industry was operating at full capacity.

- The increase in lower-48 December capacity utilization is again largely attributable to the 1.6 percentage point increase reported for the Offshore Gulf region. It is also interesting to note that the Offshore Gulf region is the only survey region which reported a December capacity utilization less than its maximum feasible capacity level, suggesting that this region may be the only underutilized lower-48 gas production source in the winter peak season.

METHODOLOGY

In February of 1997, NGSA asked the top 500 natural gas production companies to provide survey information on their regional natural gas sales and productive field capacity in the lower-48 states. This information was used to provide an estimate of the 1995 and 1996 utilization levels of natural gas productive capacity. The responses of 103 companies are included in the 1997 survey results. These 103 companies are listed in Appendix A.[1]

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[1] Additional surveys had been received but were not included in the final survey tabulation due either to: 1) an incomplete survey response, or 2) data inconsistencies or errors which could not be resolved by the accountants.

This year's survey techniques are identical to those employed last year. All survey information was collected on an operator basis, rather than on an ownership basis, for the seven lower-48 regions defined in Appendix B. A gas field's operator generally has a better understanding of that field's operating characteristics and potential capacity than the non-operator owners. Conducting the survey on an operating basis also eliminated the possibility of a "double counting" problem where co-owners of a gas field reporting the same information more than once.

The survey collected information on both connected and unconnected gas field capacity. Connected gas field capacity is defined as volume of natural gas that can be injected into the transmission system on a sustainable thirty (30) day basis at a specific point in time (i.e., January 1st). Unconnected gas field capacity is the volume of productive gas capacity (associated with completed gas wells) which could not be injected into the transmission system at that time, but could be injected within a year after the January 1st reference point. For further clarification of these and other survey terms, a Glossary Of Terminology accompanies this report in Appendix C.

Respondents could answer the survey on either a "wet" or "dry" gas basis.[2] All "wet" gas figures were converted into the equivalent "dry" gas figures, by the accountants doing the tabulation, using the conversion factors developed in Appendix D. The conversion ratio between "wet" gas and "dry" gas was developed using the natural gas production data reported by the Energy Information Administration document entitled: "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1995 Annual Report". The conversion ratio equals a region's total gas production, as expressed on a dry basis, divided by the region's total gas production, as expressed on a wet basis. Multiplying this conversion factor by the survey's "wet" gas volumes provides the estimated "dry" gas volumes.

The 1997 survey requested all survey respondents to submit estimates of connected and unconnected field capacity for both January 1, 1996 and January 1, 1997. Annual and December field deliveries were also requested for both 1995 and 1996. The reporting of the same information for two points in time permits an analysis of year-to-year trends for the same group of respondents.

All survey respondents were asked to neutralize the impact on productive capacity and deliveries that would result from the sale or purchase of gas producing properties which they operated. If a purchase or sale had occurred during 1996, for example, then the respondents were to adjust the January 1, 1996 productive capacity figures and the 1995 and 1996 field delivery figures to put these figures on

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[2] "Wet" gas refers to the presence of natural gas liquids (e.g., butane, propane, ethane, etc.) in the gas stream; it does not refer to the water content of the gas. In contrast, "dry" natural gas refers to the absence of natural gas liquids in the gas stream. Both "wet" and "dry" gas has already been stripped of any excess water.

a totally consistent basis with the January 1, 1997 situation. Thus, the sale and/or purchase of gas producing properties should not play a role in either increasing or decreasing the gas volumes reported for productive capacity and deliveries.

Finally, the survey asked respondents to estimate the connected capacity's maximum feasible capacity utilization level on both an Annual and December basis. These maximum feasible capacity utilization levels are compared to the actual capacity utilization levels as a means for determining how close capacity was operating to the practical productive limits imposed by maintenance and weather conditions. The maximum feasible capacity utilization levels, however, are neither well defined nor well measured. Rather, they are intended to provide a rough estimate of the practical operating limits previously experienced by the industry.

The individual survey responses were collected and aggregated on a confidential basis by the accounting firm of Deloitte & Touche.

SURVEY COVERAGE OF LOWER-48 NATURAL GAS PRODUCTION

The 103 survey respondents were responsible for 60.3 percent of 1995 lower-48 dry gas production (see Schedule 1). Regional survey coverage is illustrated in Figure 1. On a regional basis, the survey respondents accounted for over 50 percent of the 1995 production in four survey regions: the Offshore Gulf with 80.6 percent coverage, the Rocky Mountain/Pacific with 56.6 percent coverage, the Permian Basin with 55.4 percent coverage, and the Offshore Gulf with 55.1 percent coverage. The three remaining regions reported between 40 and 50 percent coverage: the San Juan Basin with 49.0 percent coverage, the Anadarko Basin with 48.3 percent coverage, and the East/North Central region with 40.6 percent coverage.

Because the survey was not conducted on a random statistical basis, it is impossible to ascertain whether the capacity utilization results are indicative of industry-wide conditions. The survey results regarding connected capacity and field deliveries should not be extrapolated to represent the entire natural gas production industry. Rather, these survey results should be construed as pertaining only to the circumstances reported by the 103 survey respondents.

However, the capacity utilization levels reported for the survey may be more representative of the industry in regions with a high survey coverage. For example, the survey results are probably representative of deliverability conditions in the Offshore Gulf region because the survey coverage is over 80 percent. Conversely, the 41 percent survey coverage for the East/North Central region implies that the survey results are less representative of deliverability conditions in this region.

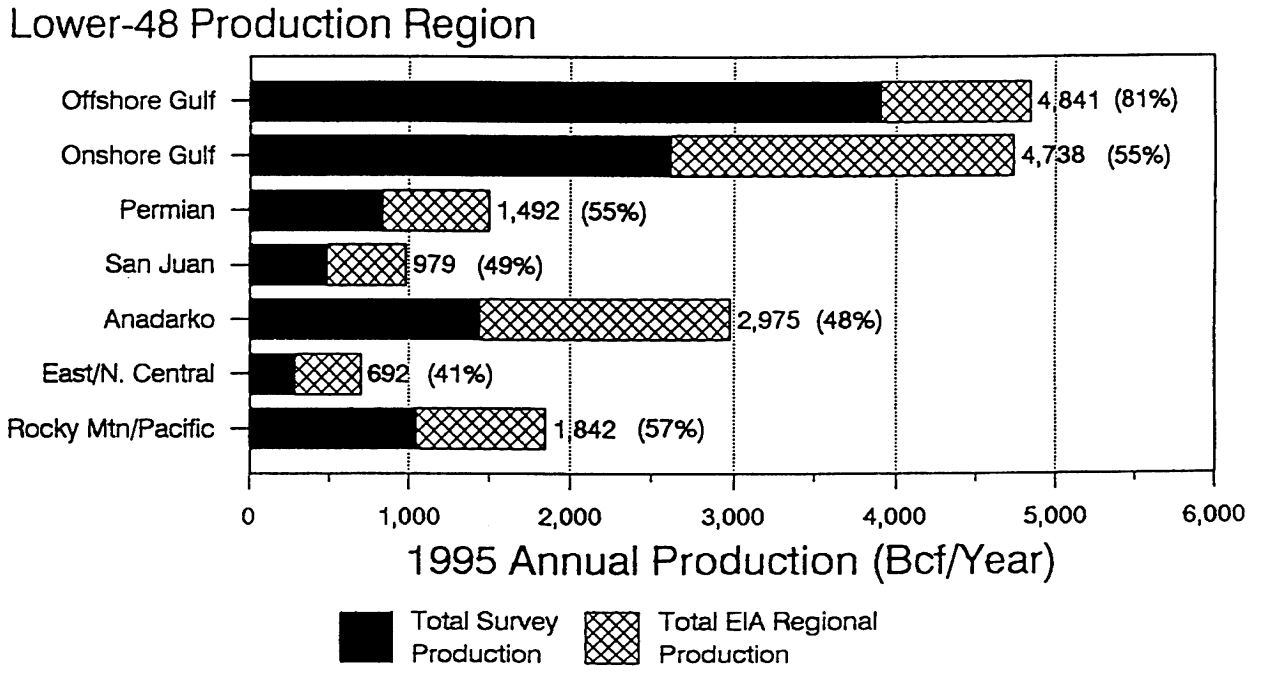
SCHEDULE 1 - RESULTS OF THE 1997 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY: SURVEY COVERAGE RELATIVE TO EIA 1995 PRODUCTION

SURVEY REGIONS	ANNUAL 1995 SURVEY PRODUCTION (MMcf/Day)	(Bcf/Year)	1995 EIA GAS PRODUCTION (Bcf/Year)	PERCENT OF EIA GAS PRODUCTION
1 OFFSHORE GULF	10,695	3,904	4,841	80.6%
2 ONSHORE GULF	7,148	2,609	4,738	55.1%
3 PERMIAN BASIN	2,266	827	1,492	55.4%
4 SAN JUAN BASIN	1,314	480	979	49.0%
5 ANADARKO	3,937	1,437	2,975	48.3%
6 EAST/NORTH CENTRAL	770	281	692	40.6%
7 ROCKY MOUNTAIN/PACIFIC	2,859	1,043	1,842	56.6%
TOTAL LOWER-48	28,989	10,581	17,559	60.3%
ONSHORE & OFFSHORE GULF REGIONS COMBINED	17,844	6,513	9,579	68.0%

EIA Data Source: "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids: 1995 Annual Report", Energy Information Administration, DOE/EIA-0216(95), November 1996, Table 8.

FIGURE 1

1997 NGSA GAS DELIVERABILITY SURVEY: SURVEY COVERAGE RELATIVE TO 1995 EIA REGIONAL PRODUCTION DATA



EIA Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1995 Annual Report

SURVEY RESULTS FOR THE U.S. LOWER-48 STATES

I. Natural Gas Field Productive Capacity

A. Changes In Connected Gas Field Capacity Between January 1, 1996 and January 1, 1997

For the 103 survey respondents, lower-48 connected field capacity increased by 882 MMcf/day for a 2.9 percent increase from January 1, 1996 to January 1, 1997 (see Schedule 2). This 2.9 percent increase in connected capacity is almost exclusively attributable to three survey regions: the Onshore Gulf with a 6.5 percent increase in connected capacity (+479 MMcf/day), the Rocky Mountain/Pacific region with a 4.5 percent increase (+143 MMcf/day), and the Offshore Gulf with a 2.0 percent increase (+236 MMcf/day). In comparison, the remaining four regions posted connected capacity increases or decreases of less than 1 percent. Of these four, the San Juan Basin is notable because it was the only survey region to report a decline in connected capacity, albeit a slight decline.

Although the Offshore Gulf region has been receiving considerable media attention due to the large gas reserves found in the deep-water Gulf, it is noteworthy that the Onshore Gulf region posted an incremental increase in productive capacity which is twice as large as that reported for the Offshore Gulf. In percentage terms, the Onshore Gulf's incremental increase in productive capacity is more than three times that of the Offshore Gulf. Thus, the notion that the Onshore Gulf is a "mature" gas geologic province with diminishing prospects for exploration and production is questionable in light of these survey results.

B. Changes In Connected And Unconnected Gas Field Capacity Between January 1, 1996 and January 1, 1997

As of January 1, 1997, unconnected field capacity accounts for 4.2 percent of the total connected and unconnected capacity, which is slightly higher than the 4.0 percent reported for January 1, 1996 (see Schedule 2). The 4.2 percent level reported for January 1, 1997 is consistent with unconnected capacity levels reported in prior surveys.

During 1996, total capacity for the 103 survey respondents increased by 985 MMcf/day for a 3.1 percent increase. This increase in the total capacity is due to increases in both connected capacity (+882 MMcf/day, +2.9 percent) and in unconnected capacity (+102 MMcf/day, +7.9 percent). Almost all of the increase in unconnected capacity occurred in the Offshore Gulf region, which increased by 115 MMcf/day during 1996.

SCHEDULE 2 - RESULTS OF THE
1997 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY
CONNECTED & UNCONNECTED NATURAL GAS PRODUCTIVE FIELD CAPACITY
(On A Dry Gas Basis)

	SURVEY REGION	JAN. 1st 1996	JAN. 1st 1997	CHANGE IN MAGNITUDE	PERCENT CHANGE
CONNECTED NATURAL GAS FIELD CAPACITY (MMcf/Day)	1 OFFSHORE GULF	11,598	11,833	236	2.0%
	2 ONSHORE GULF	7,417	7,896	479	6.5%
	3 PERMIAN BASIN	2,345	2,357	13	0.5%
	4 SAN JUAN BASIN	1,370	1,359	(11)	-0.8%
	5 ANADARKO BASIN	4,116	4,133	17	0.4%
	6 EAST/N. CENTRAL	805	811	6	0.8%
	7 ROCKY MTN/PACIFIC	3,143	3,286	143	4.5%
	TOTAL	30,793	31,676	882	2.9%
UNCONNECTED NATURAL GAS FIELD CAPACITY (MMcf/Day)	1 OFFSHORE GULF	1,003	1,119	115	11.5%
	2 ONSHORE GULF	109	118	9	8.5%
	3 PERMIAN BASIN	15	15	0	2.0%
	4 SAN JUAN BASIN	25	1	(24)	-97.2%
	5 ANADARKO BASIN	94	102	8	8.3%
	6 EAST/N. CENTRAL	23	19	(3)	-14.2%
	7 ROCKY MTN/PACIFIC	30	27	(3)	-11.1%
	TOTAL	1,298	1,400	102	7.9%
TOTAL CONNECTED AND UNCONNECTED NATURAL GAS FIELD CAPACITY (MMcf/Day)	1 OFFSHORE GULF	12,601	12,952	351	2.8%
	2 ONSHORE GULF	7,526	8,015	489	6.5%
	3 PERMIAN BASIN	2,360	2,372	13	0.5%
	4 SAN JUAN BASIN	1,394	1,360	(35)	-2.5%
	5 ANADARKO BASIN	4,210	4,234	25	0.6%
	6 EAST/N. CENTRAL	828	831	3	0.4%
	7 ROCKY MTN/PACIFIC	3,173	3,312	139	4.4%
	TOTAL	32,091	33,076	985	3.1%

UNCONNECTED CAPACITY AS A PERCENT OF TOTAL CAPACITY (Percent)	1 OFFSHORE GULF	8.0%	8.6%
	2 ONSHORE GULF	1.4%	1.5%
	3 PERMIAN BASIN	0.6%	0.6%
	4 SAN JUAN BASIN	1.8%	0.1%
	5 ANADARKO BASIN	2.2%	2.4%
	6 EAST/N. CENTRAL	2.7%	2.3%
	7 ROCKY MTN/PACIFIC	0.9%	0.8%
	TOTAL	4.0%	4.2%

Three of the seven survey regions posted significant increases in total connected and unconnected field capacity. The Onshore Gulf showed the largest increase in total capacity, which rose by 489 MMcf/day for a 6.5 percent increase. The next most significant increase in total capacity occurred in the Offshore Gulf which posted an increase of 351 MMcf/day (+2.8 percent). A significant increase in total capacity also occurred in the Rocky Mountain/Pacific region (+139 MMcf/day, +4.4 percent). The only survey region to report a significant decrease in total capacity was the San Juan Basin which posted a 2.5 percent reduction (-35 MMcf/day). Finally, the three remaining regions -- the Anadarko Basin, the Permian Basin, and the East/North Central region -- all posted slight increases in total capacity, amounting to between 0.4 and 0.6 percent.

II. Gas Field Productive Capacity Utilization

Productive capacity utilization (i.e., field deliveries divided by connected capacity) can be compared to both prior year utilization levels and to the maximum feasible capacity utilization level. Comparing the current year's utilization level to that of prior years indicates whether the capacity surplus is growing or diminishing. Comparing the current utilization level to the maximum feasible capacity utilization level indicates the degree to which the industry is operating close to its full potential.

A. Productive Capacity Utilization Levels For 1995 And 1996

Schedule 3 and Figures 2 and 3 show both regional and lower-48 annual capacity utilization levels. Because lower-48 connected capacity for the 103 respondents increased by 2.9 percent during 1996, while field deliveries increased by 3.9 percent, annual gas capacity utilization increased from 94.1 percent in 1995 to 95.0 percent in 1996.

As shown in Figure 3, three regions posted significant increases in capacity utilization. The largest regional increase in capacity utilization occurred in the Offshore Gulf which increased by 2.8 percentage points, from 92.2 percent in 1995 to 95.1 percent in 1996. The Offshore Gulf's increase in utilization is due to a 5.2 percent rise in gas field deliveries which more than offset the 2.0 percent increase in productive capacity. The next largest regional increase in capacity utilization occurred in the Rocky Mountain/Pacific region which rose from 90.9 to 92.3 percent. Rocky Mountain/Pacific capacity utilization rose primarily because annual gas deliveries rose by 6.1 percent, thereby outpacing the 4.5 percent increase in its productive capacity. The third region posting a significant increase in annual capacity utilization was the San Juan Basin, which posted a 1.2 percentage point increase in utilization. The San Juan's increase is attributable both to the growth in gas deliveries and to the decline in productive capacity.

SCHEDULE 3 - RESULTS OF THE
1997 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY
ANNUAL CONNECTED CAPACITY UTILIZATION LEVELS
(On A Dry Gas Basis)

	SURVEY REGION	JAN. 1st 1996	JAN. 1st 1997	CHANGE IN MAGNITUDE	PERCENT CHANGE
CONNECTED NATURAL GAS FIELD CAPACITY (MMcf/Day)	1 OFFSHORE GULF	11,598	11,833	236	2.0%
	2 ONSHORE GULF	7,417	7,896	479	6.5%
	3 PERMIAN BASIN	2,345	2,357	13	0.5%
	4 SAN JUAN BASIN	1,370	1,359	(11)	-0.8%
	5 ANADARKO BASIN	4,116	4,133	17	0.4%
	6 EAST/N. CENTRAL	805	811	6	0.8%
	7 ROCKY MTN/PACIFIC	3,143	3,286	143	4.5%
	TOTAL	30,793	31,676	882	2.9%

	SURVEY REGION	ANNUAL 1995	ANNUAL 1996	CHANGE IN MAGNITUDE	PERCENT CHANGE
ANNUAL NATURAL GAS FIELD DELIVERIES (MMcf/Day)	1 OFFSHORE GULF	10,695	11,250	554	5.2%
	2 ONSHORE GULF	7,148	7,489	341	4.8%
	3 PERMIAN BASIN	2,266	2,294	27	1.2%
	4 SAN JUAN BASIN	1,314	1,320	6	0.4%
	5 ANADARKO BASIN	3,937	3,972	35	0.9%
	6 EAST/N. CENTRAL	770	749	(21)	-2.7%
	7 ROCKY MTN/PACIFIC	2,859	3,032	174	6.1%
	TOTAL	28,989	30,105	1,116	3.9%

	SURVEY REGION	ANNUAL 1995	ANNUAL 1996	CHANGE IN PERCENT	ANNUAL MAXIMUM FEASIBLE CAPACITY LEVEL
ANNUAL GAS FIELD CAPACITY UTILIZATION (Percent)	1 OFFSHORE GULF	92.2%	95.1%	2.8	96.8%
	2 ONSHORE GULF	96.4%	94.8%	-1.5	96.7%
	3 PERMIAN BASIN	96.7%	97.3%	0.6	96.4%
	4 SAN JUAN BASIN	95.9%	97.1%	1.2	96.3%
	5 ANADARKO BASIN	95.7%	96.1%	0.5	95.7%
	6 EAST/N. CENTRAL	95.6%	92.3%	-3.3	96.0%
	7 ROCKY MTN/PACIFIC	90.9%	92.3%	1.3	96.3%
	TOTAL	94.1%	95.0%	0.9	96.5%
	ONSHORE/OFFSHORE GULF REGIONS COMBINED	93.8%	95.0%	1.1	96.8%

FIGURE 2

1997 NGSA NATURAL GAS DELIVERABILITY SURVEY: LOWER-48 CAPACITY UTILIZATION FOR 1995 AND 1996

Annual Capacity Utilization (Percent)

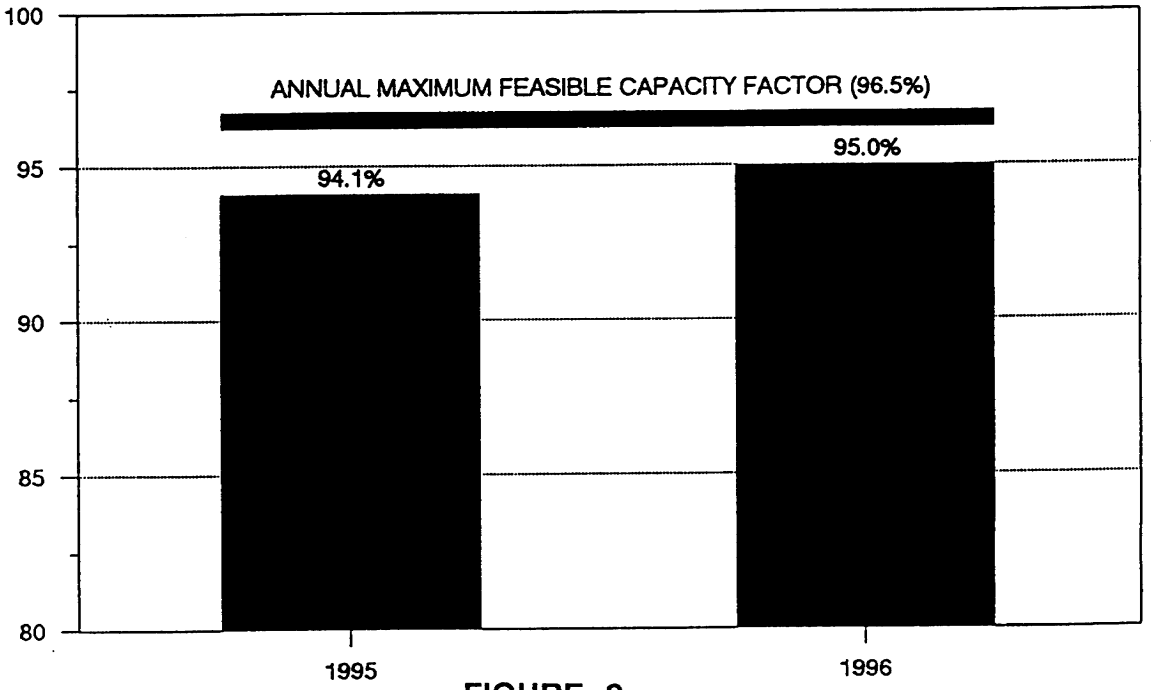
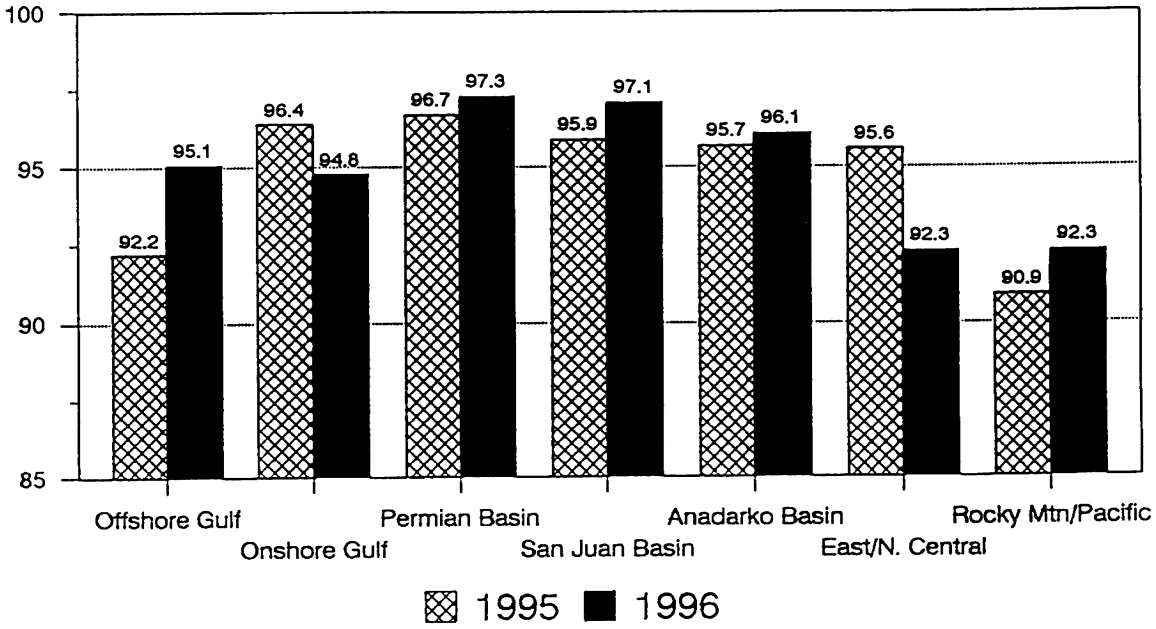


FIGURE 3

1997 NGSA NATURAL GAS DELIVERABILITY SURVEY: ANNUAL REGIONAL CAPACITY UTILIZATION FOR 1995 AND 1996

Capacity Utilization (Percent)



Even though lower-48 capacity utilization increased in 1996, two survey regions -- the Onshore Gulf and the East/North Central regions -- posted significant reductions in their capacity utilization. The East/North Central's annual utilization level dropped by 3.3 percentage points, while the Onshore Gulf's annual capacity utilization level dropped by 1.5 percentage points to a 1996 level of 94.8 percent. In the East/North Central, annual capacity utilization declined primarily due to the 2.7 percent drop in annual gas deliveries. In contrast, Onshore Gulf capacity utilization dropped because the growth in productive capacity (+6.5 percent) outpaced the growth in field deliveries (+4.8 percent).

The remaining two survey regions -- Permian and Anadarko Basins -- posted slight improvements in capacity utilization, amounting to 0.6 and 0.5 percentage points gains, respectively.

B. Comparing Annual Capacity Utilization To The Annual Maximum Feasible Capacity Utilization

A comparison of actual annual utilization levels to the maximum feasible capacity utilization establishes the relative amount of unused productive gas field capacity. Figure 2 compares 1995 and 1996 lower-48 capacity utilization levels to the Annual Maximum Feasible Capacity Utilization Level. Because of the small 1.5 percentage point spread between the 1996 utilization level of 95.0 percent and the annual maximum feasible capacity utilization level of 96.5 percent, it appears that the gas production industry is operating at close to full capacity.

The spread between the actual annual utilization, and that which is feasible, varies by survey region. The largest spread between actual and feasible utilization occurred in the Rocky Mountain/Pacific and East/North Central regions, amounting to 4.0 and 3.7 percentage points, respectively. Both the Offshore Gulf and Onshore Gulf regions posted spreads amounting to just under two (2) percentage points. In contrast, three survey regions -- the Permian, Anadarko, and San Juan Basins -- reported 1996 annual capacity utilization levels that were slightly greater than their annual maximum feasible capacity levels.[3] Indeed, as gas producers increasingly become more adept at maximizing the availability of their productive capacity, their capacity's current capabilities can be expected to exceed their historic experience.

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[3] The maximum feasible capacity utilization factor is a measure of the historic availability of wellhead gas production, as experienced over the last five to ten years. Consequently, utilization levels for any particular survey period can exceed the values reported for this historic measure.

C. Comparing December Capacity Utilization Levels To The December Maximum Feasible Capacity Utilization

While it is clearly important to have information on the capacity utilization of productive capacity on an annual basis, it is equally important to compare this annual capacity utilization to winter utilization levels. December capacity utilization is one measure of the productive capacity employed during winter production periods.

Schedule 4 reports the 1995 and 1996 December capacity utilization levels along with the December maximum feasible capacity factors. Two differences with the annual figures are apparent. First, December 1996 utilization levels are 3.3 percentage points greater than the 1996 annual utilization levels, while December 1995 utilization is 3.5 percentage points greater than the 1995 annual level. This is consistent with prior surveys which have always reported December utilization levels to be higher than the annual average utilization level. Second, December 1996 capacity utilization of 98.3 percent is only 0.7 percentage points higher than the prior December 1995 figure of 97.6 percent. Both of these trends indicate that the seasonal variability in gas production diminished somewhat during 1996. This observation further supports the notion that gas producers are operating closer to full capacity on an annual basis.

As shown in Figure 4, December capacity utilization posted significant increases in three of the seven survey regions. The largest increases in December 1996 utilization levels occurred in the following regions: the East/North Central region (+2.6 percentage points), the Offshore Gulf (+1.6 percentage points), and the Onshore Gulf (+1.0 percentage points). The Permian Basin posted a modest increase in December utilization levels, amounting to a gain of +0.6 percentage points.

In contrast, three survey regions posted declines in December 1996 capacity utilization: the Rocky Mountain/Pacific region (-1.1 percentage points), the San Juan Basin (-0.7 percentage points), and the Anadarko Basin (-0.6 percentage points). The slight decline in capacity utilization for these three regions is reasonable in that they may have been operating above sustainable production levels in December 1995.

Six survey regions posted a December 1996 capacity utilization which exceeded their December Maximum Feasible Capacity Utilization; they are: the Onshore Gulf, the Permian Basin, the San Juan Basin, the Anadarko Basin, the East/North Central region, and the Rocky Mountain/Pacific Region. The regional propensity to exceed the maximum feasible utilization level is replicated on a total lower-48 basis, where the lower-48 December 1996 capacity utilization of 98.3 percent exceeded the lower-48 December Maximum Feasible Capacity Level of 96.7 percent. This indicates that gas producers were operating close to or at full capacity during December 1996.

SCHEDULE 4 - RESULTS OF THE
1997 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY
DECEMBER CONNECTED CAPACITY UTILIZATION LEVELS
(On A Dry Gas Basis)

	SURVEY REGION	JAN. 1st 1996	JAN. 1st 1997	CHANGE IN MAGNITUDE	PERCENT CHANGE
CONNECTED NATURAL GAS FIELD CAPACITY (MMcf/Day)	1 OFFSHORE GULF	11,598	11,833	236	2.0%
	2 ONSHORE GULF	7,417	7,896	479	6.5%
	3 PERMIAN BASIN	2,345	2,357	13	0.5%
	4 SAN JUAN BASIN	1,370	1,359	(11)	-0.8%
	5 ANADARKO BASIN	4,116	4,133	17	0.4%
	6 EAST/N. CENTRAL	805	811	6	0.8%
	7 ROCKY MTN/PACIFIC	3,143	3,286	143	4.5%
	TOTAL	30,793	31,676	882	2.9%

	SURVEY REGION	DEC. 1995	DEC. 1996	CHANGE IN MAGNITUDE	PERCENT CHANGE
DECEMBER NATURAL GAS FIELD DELIVERIES (MMcf/Day)	1 OFFSHORE GULF	10,935	11,341	406	3.7%
	2 ONSHORE GULF	7,380	7,934	554	7.5%
	3 PERMIAN BASIN	2,384	2,412	28	1.2%
	4 SAN JUAN BASIN	1,367	1,347	(20)	-1.4%
	5 ANADARKO BASIN	4,107	4,101	(6)	-0.2%
	6 EAST/N. CENTRAL	772	799	27	3.5%
	7 ROCKY MTN/PACIFIC	3,099	3,204	105	3.4%
	TOTAL	30,044	31,138	1,094	3.6%

	SURVEY REGION	DEC. 1995	DEC. 1996	CHANGE IN PERCENT	DECEMBER MAXIMUM FEASIBLE CAPACITY LEVEL
DECEMBER GAS FIELD CAPACITY UTILIZATION (Percent)	1 OFFSHORE GULF	94.3%	95.8%	1.6	96.6%
	2 ONSHORE GULF	99.5%	100.5%	1.0	97.0%
	3 PERMIAN BASIN	101.7%	102.3%	0.6	95.8%
	4 SAN JUAN BASIN	99.8%	99.1%	-0.7	97.2%
	5 ANADARKO BASIN	99.8%	99.2%	-0.6	97.0%
	6 EAST/N. CENTRAL	95.8%	98.4%	2.6	96.5%
	7 ROCKY MTN/PACIFIC	98.6%	97.5%	-1.1	96.2%
	TOTAL	97.6%	98.3%	0.7	96.7%
	ONSHORE/OFFSHORE GULF REGIONS COMBINED	96.3%	97.7%	1.4	96.8%

FIGURE 4

1997 NGSA NATURAL GAS DELIVERABILITY SURVEY: YEAR-TO-YEAR CHANGES IN CAPACITY UTILIZATION FOR BOTH ANNUAL & DECEMBER FIELD DELIVERIES

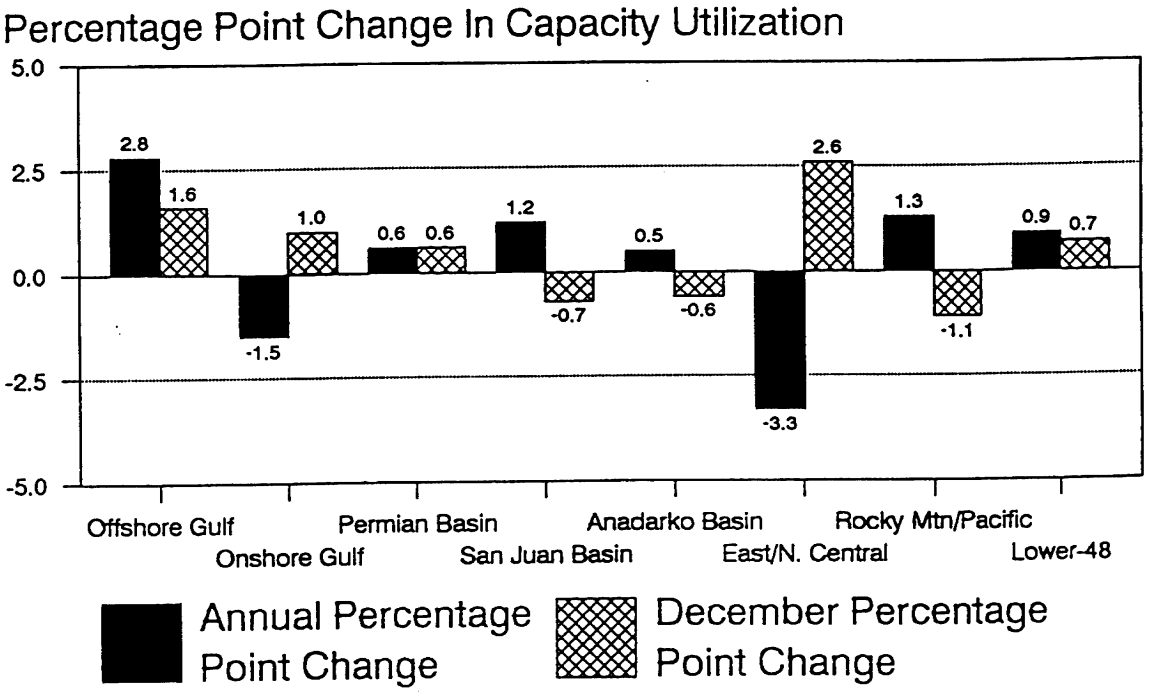
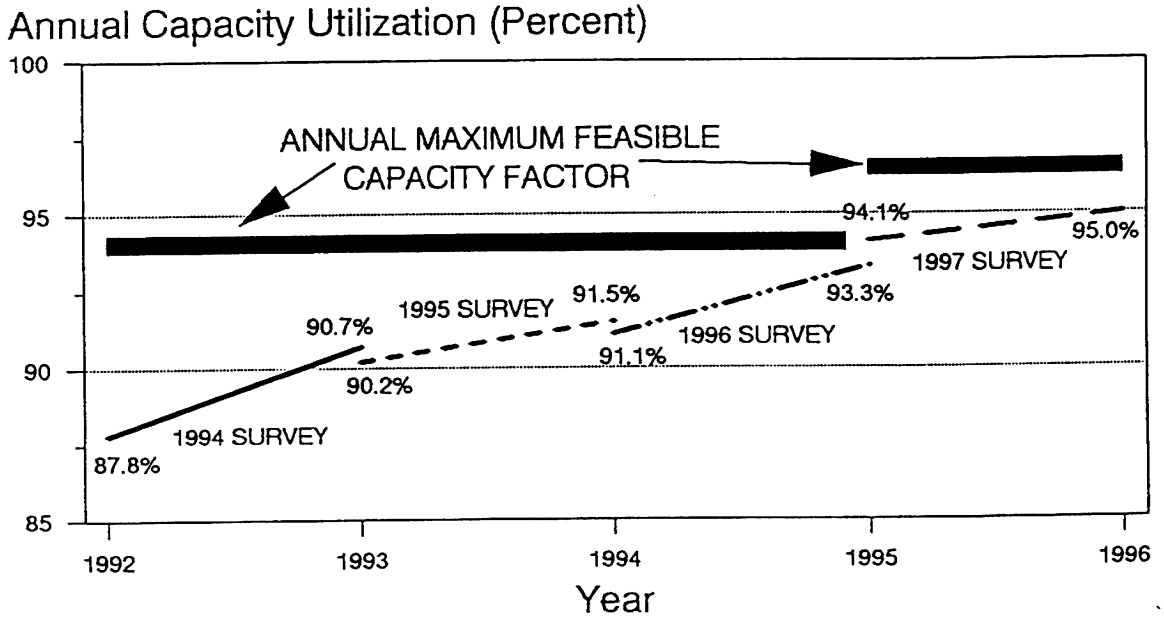


FIGURE 5

1997 NGSA GAS DELIVERABILITY SURVEY: LOWER-48 CAPACITY UTILIZATION LEVELS FOR THE LAST FOUR NGSA SURVEYS



The year reported for each survey refers to the calendar year in which the survey was conducted.

SCHEDULE 5 - RESULTS OF THE 1997 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY: COMPARABLE ANNUAL CONNECTED CAPACITY UTILIZATION LEVELS FOR THE THREE PRIOR NGSA SURVEYS (On A Dry Gas Basis)

		ANNUAL CAPACITY UTILIZATION					ANNUAL MAXIMUM FEASIBLE CAPACITY
	1994 SURVEY	1992	1993	1994	1995	1996	
1	OFFSHORE GULF	88.6%	88.8%				93.8%
2	ONSHORE GULF	89.2%	93.9%				94.4%
3	PERMIAN BASIN	89.4%	91.5%				95.2%
4	SAN JUAN BASIN	76.0%	91.6%				93.0%
5	ANADARKO BASIN	85.0%	88.2%				91.4%
6	EAST/N. CENTRAL	93.1%	93.8%				95.8%
7	ROCKY MTN/PACIFIC	89.0%	92.7%				96.0%
	TOTAL	87.8%	90.7%				93.9%
	1995 SURVEY						
1	OFFSHORE GULF		87.5%	90.3%			94.5%
2	ONSHORE GULF		93.2%	93.1%			95.2%
3	PERMIAN BASIN		93.4%	91.1%			95.2%
4	SAN JUAN BASIN		90.8%	93.4%			93.1%
5	ANADARKO BASIN		89.0%	92.9%			93.3%
6	EAST/N. CENTRAL		93.6%	91.7%			94.9%
7	ROCKY MTN/PACIFIC		91.8%	89.6%			95.6%
	TOTAL		90.2%	91.5%			94.6%
	1996 SURVEY						
1	OFFSHORE GULF			88.5%	92.0%		93.0%
2	ONSHORE GULF			92.6%	94.8%		95.7%
3	PERMIAN BASIN			92.4%	94.8%		95.2%
4	SAN JUAN BASIN			96.1%	95.7%		95.3%
5	ANADARKO BASIN			95.0%	94.3%		94.8%
6	EAST/N. CENTRAL			94.0%	95.2%		95.7%
7	ROCKY MTN/PACIFIC			89.4%	91.1%		96.7%
	TOTAL			91.1%	93.3%		94.6%
	1997 SURVEY						
1	OFFSHORE GULF				92.2%	95.1%	96.8%
2	ONSHORE GULF				96.4%	94.8%	96.7%
3	PERMIAN BASIN				96.7%	97.3%	96.4%
4	SAN JUAN BASIN				95.9%	97.1%	96.3%
5	ANADARKO BASIN				95.7%	96.1%	95.7%
6	EAST/N. CENTRAL				95.6%	92.3%	96.0%
7	ROCKY MTN/PACIFIC				90.9%	92.3%	96.3%
	TOTAL				94.1%	95.0%	96.5%

The Offshore Gulf is the only survey region which did not show a December 1996 capacity utilization which exceeds the December maximum feasible capacity level. This suggests that the Offshore Gulf region might be the only underutilized lower-48 gas production source in the winter peak season.

III. Comparing Current Capacity Utilization Levels With Those Of The Last Three NGSA Surveys

Even though the identity of the survey respondents changes for each survey cycle, there is sufficient continuity in the respondent group, especially among large producers, to permit a comparison of this year's survey results to that of the three prior surveys. Schedule 5 and Figure 5 compare the regional capacity utilization levels for this year's survey with those of the three prior surveys.

Both Schedule 5 and Figure 5 provide insight on the long-term direction of lower-48 capacity utilization trends. For the time period spanning 1992 through 1996, overall lower-48 capacity utilization increased by approximately +7.2 percentage points, going from 87.8 percent in 1992 to 95.0 percent in 1996.

However, just as annual capacity utilization has increased, gas producers also reported an increase in their annual maximum feasible capacity levels. In the 1994 through 1996 surveys, producers reported the annual maximum feasible capacity level to be between 93.9 and 94.6 percent. In the latest survey, producers raised their estimate of this factor to 96.5 percent, which is about a two (2) percentage point increase. This increase in the maximum feasible capacity utilization level could have resulted for a couple of reasons. First, as gas fields are operated closer to their full productive potential, producers obtain a clearer estimate of what can realistically be produced. Second, improvements in management and technology could also be responsible for this increase in the maximum feasible capacity utilization. Irrespective of the underlying reasons, the survey indicates that gas producers are capable of operating their productive assets at a higher level of utilization than they thought was possible earlier this decade.[4]

Because wellhead gas utilization has increased much faster than the increase in the annual maximum feasible capacity level, the amount of spare productive capacity has declined over time. For example, the 1994 NGSA survey reported a 3.2 percentage point spread between 1993 lower-48 annual utilization and the maximum feasible capacity (See Schedule 5). In the latest survey, the spread between actual

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[4] Gas producer estimates of the annual maximum feasible capacity level have shown a slow but steady rise since the initiation of the NGSA survey process. The lowest annual maximum feasible capacity level was posted for 1988 at a level of 92.1 percent.

annual capacity and the maximum feasible amounts to 1.5 percentage points. In this context, the improvement in gas field utilization has outpaced improvements in the gas producers ability to operate closer to full capacity (i.e., 100 percent of connected capacity).

APPENDIX A

SURVEY RESPONDENTS INCLUDED IN THE NGSA DELIVERABILITY SURVEY RESULTS

1. AEDC (USA) Inc.
2. AGIP Petroleum, Inc.
3. Alamco, Inc.
4. Amoco Exploration & Production
5. Anadarko Petroleum Corp.
6. Badger Oil Corporation
7. Bakersfield Energy Resources
8. Brammer Engineering, Inc.
9. Browning Oil Company
10. Burk Royalty Company
11. Cabot Oil & Gas Corp.
12. Callon Petroleum Operating Co.
13. CGAS, Inc.
14. Chandler & Associates, Inc.
15. Chevron USA Production Company
16. CMS NOMECO Oil & Gas Co.
17. CNG Producing Company
18. Coastal Oil & Gas Corp.
19. Cockrell Oil Corp.
20. Columbia Natural Resources, Inc.
21. Columbus Energy Corp.
22. Conoco Inc.
23. Devon Energy Corp. (Nevada)
24. Dorchester Hugoton Ltd.
25. Dugan Production Corp.
26. Eastern American Energy Corp.
27. Elf Exploration, Inc.
28. Energy Management Corp.
29. Enron Oil & Gas Company
30. Exploration Partners, LLC
31. Exxon Company, U.S.A.
32. Fina Natural Gas Company
33. Flores & Rucks, Inc.
34. Forest Oil Corp.
35. Great River Oil & Gas Corp.
36. H&L Operating Company
37. Hurd Enterprises, Ltd.
38. J. Cleo Thompson
39. John H. Young, Inc.
40. Kaiser-Francis Oil Company
41. Kerr-McGee Corp.
42. Kriti Exploration, Inc.
43. Louisiana Land & Expl. Co., The
44. Luff Exploration Co.
45. Maguire Oil Company
46. Maralo, Inc.
47. Marathon Oil Company
48. Mariner Energy, Inc.
49. Mason Producing Inc.
50. Maynard Oil Company
51. Meridian Exploration Corp.
52. Mesa Inc.
53. Michael Petroleum Corp.
54. Mitchell Energy Corp.
55. Mobil Exploration & Producing U.S. Inc.
56. Murphy Exploration & Production
57. National Fuel Corporation
58. Nearburg Producing Company
59. Newfield Exploration Company
60. North American Resources Company
61. Omimex Energy, Inc.
62. ONEOK Inc.
63. ORYX Energy Corp.
64. Oxford Oil Company
65. Oxley Petroleum
66. Parten Operating Inc.
67. Penn Virginia Oil & Gas Corp.
68. Petroleum Development Corp.
69. Phillips Petroleum Company
70. Pogo Producing Company
71. Prima Energy Corp.
72. Quintana Petroleum Corp.
73. Reynolds Metals Co. O&G Division
74. River Gas Corp.
75. Sanches-O'Brien Oil & Gas Corp.
76. Seagull Energy E&P Inc.
77. Seneca Resources Corp.
78. Shell Oil Company
79. Sonat Exploration Company

80. Southwestern Energy Production Co.
81. Sullivan and Company
82. Swift Energy Company
83. Taurus Exploration, Inc.
84. Tesoro E&P Company, L.P.
85. Texaco Exploration & Production Inc.
86. Thums Long Beach Company
87. Tidelands Oil Production Co.
88. Toklan Oil & Gas Corp.
89. Torch Energy Advisors, Inc.
90. Total Minatome Corp.
91. TransTexas Gas Corp.
92. U.S. Department of Energy
93. U.S. DOE - NPOSR-CUW
94. U.S. Operating, Inc.
95. Union Oil Company of California
96. Union Pacific Resources
97. Van Operating Ltd.
98. Vastar Resources, Inc.
99. Wagner & Brown, Ltd.
100. Walter Oil & Gas Corp.
101. Williford Energy Co.
102. Wiser Oil Company, The
103. Yates Petroleum Corp.

APPENDIX B

DEFINITION OF NGSA SURVEY REGIONS

The survey asked for the natural gas field deliveries, productive capacity, and maximum feasible capacity utilization levels for seven lower-48 regions and for the total lower-48 as a whole. The regional breakdown was developed around the major natural gas production basins and the markets they tend to serve. Forty two states are explicitly included in one of the seven regions. Only the six New England states are excluded from consideration due to their lack of any known natural gas production. Any productive capacity in New England should have been included in the East/North Central region.

1. **Offshore Gulf Coast**: Includes all the offshore Gulf field deliveries and productive capacity, both in state and federal jurisdictions, for the states of Alabama, Florida, Louisiana, Mississippi, and Texas.

2. **Onshore Gulf Coast**: Includes all onshore field deliveries and productive capacity for Alabama, Florida, Georgia, Louisiana, Mississippi, and Texas Railroad Districts: 1, 2, 3, 4, 5, & 6.

3. **Permian Basin**: Includes 15 eastern counties of New Mexico (Chaves, Colfax, Curry, De Baca, Eddy, Guadalupe, Harding, Lea, Lincoln, Mora, Otero, Quay, Roosevelt, San Miguel, and Union) plus the Texas Railroad Districts: 7B, 7C, 8, and 8A.

4. **San Juan Basin**: Includes the 18 western counties of New Mexico (Bernalillo, Catron, Cibola, Dona Ana, Grant, Hidalgo, Los Alamos, Luna, McKinley, Rio Arriba, Sandoval, San Juan, Santa Fe, Sierra, Socorro, Taos, Torrance, and Valencia).

5. **Anadarko Basin**: Includes Arkansas, Kansas, Oklahoma, and Texas Railroad Districts: 9 and 10.

6. **East/North Central**: All onshore and offshore gas field deliveries and productive capacity for the states of: Delaware, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

7. **Rocky Mountain/Pacific**: Includes both onshore and offshore field deliveries and productive capacity associated with: Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

8. **Total U.S. Lower-48**: Includes both onshore and offshore field deliveries and productive capacity for all the regions listed.

APPENDIX C

GLOSSARY OF TERMINOLOGY FOR THE 1997 NATURAL GAS SUPPLY ASSOCIATION SURVEY ON NATURAL GAS FIELD DELIVERIES AND PRODUCTIVE CAPACITY

WELLHEAD PRODUCTIVE CAPACITY:

Connected Field Capacity (a.k.a. Productive Capacity)

Connected Field Capacity is defined as the rate at which gas can be physically injected into the intrastate and interstate pipeline network, on a 30-day sustainable basis, under the best of operating conditions (i.e., excluding planned and unplanned downtime). Because the sustainable production rate of a gas field can be lower than the sum of individual gas well deliverability rates, the connected capacity is defined on a field basis rather than on a well basis.

Connected field capacity also takes into account the capacity limitations imposed by gathering systems and gas processing plants. For example, if a group of wells can physically produce 100 MMcf/day of dry gas, but the gathering system can only transport 90 MMcf/day and the gas processing plant can only produce 70 MMcf/day of dry gas, then the connected field capacity is stated as 70 MMcf/day. The difference between the 100 MMcf/day well production potential and the 70 MMcf/day actually produced by the gas processing plant (i.e., 30 MMcf/day) is considered unconnected field capacity.

Gas productive capacity used to operate gas production and processing facilities was excluded from the survey's consideration.

Unconnected Field Capacity

Unconnected Field Capacity refers to two different situations. The first situation it addresses is gas wells that have been physically drilled, whether or not physically completed, which could be connected to the pipeline network within a one year period. No specific plans to connect these wells within the

next year are necessary for its inclusion in this category. Unconnected field capacity also includes any capacity physically connected to the pipeline network, but unable to produce due to existing gathering and processing limitations.

Natural gas that must be reinjected into the reservoir to maintain reservoir pressure and oil production is excluded from both capacity categories. On the other hand, natural gas being reinjected into the reservoir only because it has no immediate market is either connected capacity (i.e., it could be physically shipped to end-use markets without any impediments) or unconnected capacity (i.e., a bottleneck prevents immediate marketability, but this bottleneck could be removed in one year).

ANNUAL NATURAL GAS FIELD DELIVERIES:

Annual Natural Gas Field Deliveries include all gas deliveries made during the calendar years of 1995 and 1996. The survey emphasizes the level of gas delivered to the transmission network, because a natural gas sale might be put on the accounting books at a time different from that associated with the actual injection of that gas into the transmission network. Natural gas produced and consumed in the field in order to run production and gas processing facilities is not included in the total deliveries figure.

DECEMBER NATURAL GAS FIELD DELIVERIES:

December Natural Gas Field Deliveries include all gas deliveries made during December 1995 and December 1996. The survey emphasizes the level of gas delivered to the transmission network, because a natural gas sale might be put on the accounting books at a time different from that associated with the actual injection of that gas into the transmission network. Natural gas produced and consumed in the field in order to run production and gas processing facilities is not included in the total deliveries figure.

ANNUAL PRODUCTIVE CAPACITY UTILIZATION:

The Annual Productive Capacity Utilization Level equals that year's natural gas field deliveries divided by the next year's January 1st connected capacity (e.g. Annual 1995 Capacity Utilization equals 1995 field deliveries divided by January 1, 1996 connected field capacity).

DECEMBER PRODUCTIVE CAPACITY UTILIZATION:

The December Productive Capacity Utilization Level equals that year's December natural gas field deliveries divided by the next year's January 1st connected capacity (e.g. December 1995 Capacity Utilization equals December 1995 field deliveries divided by January 1, 1996 connected field capacity).

ANNUAL MAXIMUM FEASIBLE CAPACITY UTILIZATION LEVELS

The Annual Maximum Feasible Capacity Utilization Level is stated relative to the connected field capacity. In general, the maximum feasible capacity utilization level is defined as the highest practical capacity utilization, in percentage terms, applicable to a company's connected field capacity within a specific region, and typical for a calendar year. The maximum feasible capacity utilization level is based on a company's 5 to 10 year experience with planned and unplanned downtime of gas wells and other gas production facilities.

On the other hand, the maximum feasible capacity utilization levels do not factor in the following elements: 1) the level of unconnected field capacity reported, 2) the level of gas demanded by the market place (i.e., any constraints to production resulting from low gas consumption), 3) gas production downtime due to a breakdown in the transmission and distribution system (e.g., transmission and distribution pipeline ruptures, transmission compressor failures, etc.), and 4) the natural decline in field productivity due to gas reservoir depletion effects.

The annual maximum feasible capacity utilization level provided for the total U.S. lower-48 is the average value across all seven regions, weighted by each region's connected field capacity.

DECEMBER MAXIMUM FEASIBLE CAPACITY UTILIZATION LEVELS

The December Maximum Feasible Capacity Utilization Level is stated relative to the connected field capacity. Like the Annual Maximum Feasible Capacity Utilization, December maximum feasible capacity utilization level is defined as the highest practical capacity utilization, in percentage terms, applicable to a company's connected field capacity within a specific region, and typical for a "normal" December. And like the Annual Maximum Feasible Capacity Utilization, the December figure should include the same considerations embodied in the Annual Maximum Feasible Capacity Utilization.

APPENDIX D

APPENDIX D, TABLE 1
1995 RATIO OF REGIONAL DRY GAS PRODUCTION TO WET GAS PRODUCTION
BY DEPARTMENT OF ENERGY PRODUCTION DISTRICT

REGION	WET GAS (Bcf)	DRY GAS (Bcf)	WET/DRY RATIO
ALABAMA	366	360	0.984
ALASKA	431	396	0.919
ARKANSAS	182	182	1.000
CALIFORNIA	228	216	0.947
COASTAL ONSHORE	15	14	0.933
LOS ANGELES ONSHORE	9	8	0.889
SAN JOAQUIN ONSHORE	198	188	0.949
STATE OFFSHORE	6	6	1.000
COLORADO	539	514	0.954
FLORIDA	7	6	0.857
KANSAS	714	673	0.943
KENTUCKY	71	67	0.944
LOUISIANA	1,501	1,403	0.935
NORTH	353	343	0.972
SOUTH ONSHORE	991	908	0.916
STATE OFFSHORE	157	152	0.968
MICHIGAN	168	163	0.970
MISSISSIPPI	91	91	1.000
MONTANA	52	51	0.981
NEW MEXICO	1,483	1,397	0.942
EAST	468	418	0.893
WEST	1,015	979	0.965
NEW YORK	16	16	1.000
NORTH DAKOTA	49	43	0.878
OHIO	115	115	1.000
OKLAHOMA	1,661	1,562	0.940
PENNSYLVANIA	114	113	0.991
TEXAS	5,105	4,724	0.925
RRC DIST #1	93	89	0.957
RRC DIST #2 ONSHORE	207	189	0.913
RRC DIST #3 ONSHORE	754	701	0.930
RRC DIST #4 ONSHORE	1,315	1,264	0.961
RRC DIST #5	173	167	0.965
RRC DIST #6	654	620	0.948
RRC DIST #7B	72	58	0.806
RRC DIST #7C	358	321	0.897
RRC DIST #8	702	631	0.899
RRC DIST #8A	90	64	0.711
RRC DIST #9	122	103	0.844
RRC DIST #10	503	455	0.905
STATE OFFSHORE	62	62	1.000
UTAH	178	165	0.927
VIRGINIA	52	52	1.000
WEST VIRGINIA	171	166	0.971
WYOMING	842	806	0.957
FEDERAL OFFSHORE	4,726	4,674	0.989
PACIFIC COAST	47	47	1.000
GULF OF MEXICO (LA.)	3,421	3,376	0.987
GULF OF MEXICO (TEXAS)	1,258	1,251	0.994
MISCELLANEOUS	12	11	0.917
U.S. TOTAL	18,874	17,966	0.952

Source: "Advance Summary U.S. Crude Oil, Natural Gas, And Natural Gas Liquids Reserves: 1995 Annual Report", Energy Information Administration, DOE/EIA-0216(95) October 1996, Tables 3 & 4.

APPENDIX D, TABLE 2
1995 RATIO OF REGIONAL DRY GAS PRODUCTION TO WET GAS PRODUCTION
BY NGSA SURVEY REGION

REGION	WET GAS (Bcf)	DRY GAS (Bcf)	WET/DRY RATIO
1) OFFSHORE GULF	4,898	4,841	0.988
2) ONSHORE GULF	5,004	4,738	0.947
3) PERMIAN BASIN	1,690	1,492	0.883
4) SAN JUAN BASIN	1015	979	0.965
5) ANADARKO	3,182	2,975	0.935
6) APPALACHIA/N. CENTRAL	707	692	0.979
7) ROCKY MOUNTAIN/PACIFIC	1,935	1,842	0.952
TOTAL LOWER-48	18,431	17,559	0.953
ALASKA & MISCELLANEOUS	443	407	0.919
U.S. TOTAL	18,874	17,966	0.952

Source: Appendix D, Table 1.