DOE/EIA-0542(96/4)
Distribution Category UC-950

Natural Gas Productive Capacity for the Lower 48 States 1985 Through 1997

December 1996

Energy Information Administration
Office of Oil and Gas
U.S. Department of Energy
Washington, DC 20585

Preface

The *Natural Gas Productive Capacity for the Lower 48 States 1985 Through 1997* is the fifth in this series of reports prepared by the Energy Information Administration (EIA). The four previous reports were published in 1991, 1993, 1994, and 1996.{1,2,3,4} The EIA Dallas Field Office has prepared five earlier reports regarding natural gas productive capacity. These reports, *Gas Deliverability and Flow Capacity of Surveillance Fields*, reported deliverability and capacity data for selected gas fields in major gas-producing areas.{5,6,7,8,9} The data in the reports were based on gas-well back-pressure tests and estimates of gas-in-place for each field or reservoir. These reports use proven well testing theory, most of which has been employed by industry since 1936, when the Bureau of Mines first published *Monograph 7*.{10}

This publication is used by the Congress, Federal and State agencies, industry, and other interested parties to obtain accurate data of the lower 48 States' natural gas production history and wellhead productive capacity. Capacity projections from this report are used in EIA's *Short-Term Energy Outlook Quarterly Projections*. The report also contains a projection of lower 48 States' gas production requirements and wellhead productive capacity. These data are essential for the evaluation of the adequacy of future gas supplies, especially in periods of peak heating or cooling demand.

Total demand for natural gas in the United States is met by a combination of natural gas production, underground gas storage, imported gas, and supplemental gaseous fuels. This report examines the natural gas production element of the total gas demand. Domestic natural gas production supplies the majority of the natural gas demand requirements for the lower 48 States. The production requirement continues to increase while drilling has remained at low levels, a fact that this has raised some concern about the adequacy of future gas supplies, and gas producers' ability to meet periods of peak heating or cooling demand.

A history of natural gas production and natural gas productive capacity at the wellhead, along with a projection of the same, is shown in tables and figures. Data are compiled and presented for the lower 48 States, Texas, Louisiana, California, Kansas, New Mexico, Oklahoma, Gulf of Mexico Outer Continental Shelf (OCS), Southeast area, Rocky Mountain area, and an eighteen State area that includes the remaining gas producing States. The EIA generates projections based on historical gas-well drilling and production data from State, Federal, and private sources. In addition to conventional gas-well gas, coalbed gas and oil-well gas are also included. Also presented for each category are charts showing the number of gas-well completions by year and the percent of total wellhead productive capacity by age. Alaska is excluded from this report because Alaskan gas does not enter the lower 48 States pipeline system.

Appendix A contains the methodology used for the report. Appendix B contains the model abstract. Appendix C compares the results of previous productive capacity reports. Appendix D contains the calculations and a table of productive capacity per new gas-well completion. A glossary of terms used in this report is provided to assist readers in more fully understanding the data.

This annual gas capacity report was prepared by the Dallas Field Office staff of the Reserves and Production Branch, Reserves and Natural Gas Division, Office of Oil and Gas, Energy Information Administration. General information regarding preparation of the report may be obtained from Kenneth A. Vagts, Director of the Office of Oil and Gas (202/586-6401) or John H. Wood, Director of the Dallas Field Office (214/767-2200).

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Executive Summary

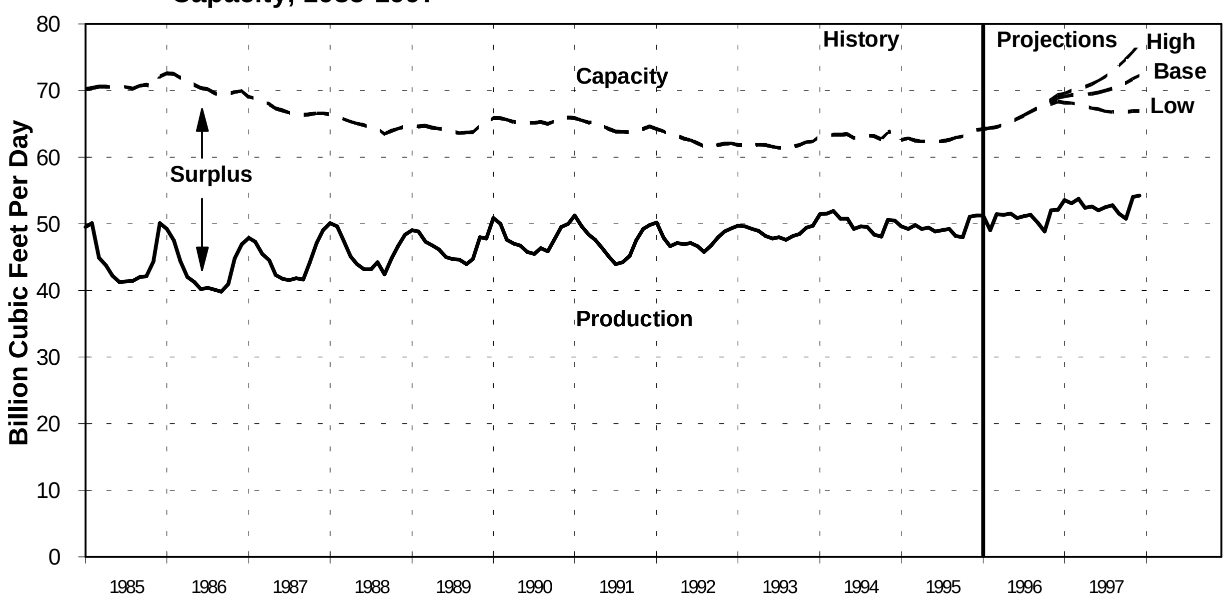
Natural gas productive capacity in the lower 48 States is expected to be adequate to meet monthly production requirements under normal weather conditions through 1997 for three drilling cases (Figure ES1). Capacity projections are shown for *low, base,* and *high* drilling cases associated with *low*, *base*, and *high* price scenarios from the Energy Information Administration *Short-Term Integrated Forecasting System, Fourth Quarter 1996* (Table ES1). Exceptionally high peak-day or peak-week heating or cooling demand may exceed projected productive capacity, or production may be limited by other factors, such as pipeline availability. Wellhead productive capacity sets the upper limit on natural gas production. Nonetheless, the natural gas industry has developed methods to meet peak demand, such as deliveries from storage and peak-day shaving. These developments have been greatly promoted at the Federal level by the movements to lessen regulation by the Federal Energy Regulatory Commission. Increased reliance on market forces also encourages industry efficiency, as customers with fuel-switching capability consume other fuels in response to higher gas prices. Lastly, effective demand might be lowered by reducing service to customers that have interruptible contracts.

This is the fifth in the series of EIA reports on natural gas wellhead productive capacity in the lower 48 States. The series document a decline in gas productive capacity beginning in 1986 that was clearly reversed in 1996. Natural gas productive capacity is projected to increase in 1996 for the *low*, *base*, and *high* drilling cases and in 1997 for the *base* and *high* cases (Figure ES1). This gradual increase in surplus capacity reflects mainly new discoveries in the Gulf of Mexico Outer Continental Shelf.

The major conclusions of this study are:

- Monthly wellhead productive capacity of dry gas will be adequate to meet production requirements in the *low, base*, and *high* cases through 1997.

Figure ES1. Lower 48 States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

- In fact, the surplus monthly productive capacity will be higher in December 1997 than in December 1995 for the *base* and *high* cases.
- In particular, the largest gas producing area, the Gulf of Mexico Federal Offshore, is expected to meet its historical market share of U.S. production and maintain a substantial surplus productive capacity.
- Beyond 1997, a sufficient number of new wells and/or imports must be added each year in order to ensure an adequate gas capacity and supply.

For decades the lower 48 States natural gas productive capacity has been adequate to meet production requirements. In the 1970's, the capacity surplus was small because of market structure (split between interstate and intrastate), increasing production requirements, and insufficient drilling. In the early 1980's lower production requirements, together with increased drilling and tight gas price incentives, led to a large surplus capacity. After 1986, this large surplus began to decline as requirements for gas increased, gas prices fell along with oil prices, and gas-well completions dropped sharply. In late December 1989, the decline in this surplus, accompanied by exceptionally high requirements and temporary weather-related production losses, led to concerns about the adequacy of productive capacity for natural gas. These concerns were moderated by the gas system's performance during the unusually severe winter weather in March 1993 and January 1994.

Monthly natural gas wellhead productive capacity estimates are for conventional and coalbed gas-well completions and oil-well completions in the lower 48 States. The different drilling levels assumed in three cases are functions of oil and gas prices and gas production requirements (Table ES1).

Beginning in 1987, coalbed gas production and capacity began a rapid increase. By the end of 1995, the coalbed gas capacity was 5 percent of the total gas-well gas capacity. After 1993, the coalbed production and capacity increased at a lower rate. Coalbed gas capacity is still projected to be 5 percent of the total at the end of 1997 in spite of a decline of coalbed gas capacity in the Southeast for 1996 and 1997.

The existence of a surplus wellhead productive capacity does not signify that the entire gas capacity could be produced and delivered. The ability of a well to deliver gas into a pipeline system (deliverability) is always equal to or less than wellhead productive capacity. Deliverability is that volume of gas that can be produced from a well, reservoir, or field during a given

Table ES1. Annual Wellhead Price, December Production, and December Productive Capacity of Gas, 1985, 1994, 1995, 1996, and 1997

Year/Case	Price (nominal dollars)	Production (billion cubic feet per day)	Productive Capacity (billion cubic feet per day)	Productive Capacity Surplus (billion cubic feet per day)	Productive Capacity Utilization (percent)
History					
1985	2.51	50.1	72.1	22.1	69.4
1994	1.88	50.5	64.0	13.5	78.9
1995	1.59	51.2	64.1	12.9	79.9
Projections					
1996/Low	1.99	52.2	68.4	16.2	76.3
1996/Base	2.07	52.2	69.0	16.8	75.6
1996/High	2.11	52.2	69.3	17.2	75.3
1997/Low	1.72	54.2	67.0	12.7	81.0
1997/Base	1.85	54.2	72.3	18.1	75.0
1997/High	2.15	54.2	77.0	22.7	70.5

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

period of time against a certain wellhead back-pressure under actual reservoir conditions, taking into account restrictions imposed by pipeline capacity, gas plant capacity, contracts, or regulatory bodies.

At the end of 1994, deliverability into the lower-48 pipeline system was estimated to be 55 billion cubic feet per day of dry gas, only 87 percent of the dry gas productive capacity at the wellhead. However, there is substantial uncertainty in this deliverability estimate. Should the surplus in wellhead productive capacity decline, more reliance would be placed on gas withdrawals from storage to meet peak heating and cooling demand. Gas storage requirements can be met by maintaining gas production that is closer to gas productive capacity throughout the year. This would lead to smaller seasonal variations in gas production.

1. Introduction

Natural gas demand in the lower 48 States has been increasing during the last few years. Natural gas-well drilling has remained at low levels during these same years. This has raised concern about the adequacy of future gas supplies, especially in periods of peak heating or cooling demand.

Total demand for natural gas in the United States is met by a combination of natural gas production, underground gas storage, imported gas, and supplemental gaseous fuels. Unpredictable market forces affect the number of new well completions and recompletions, which are related to drilling activity and rig efficiency. These forces include prices for oil and gas, imports, gas storage, regulatory changes, market dynamics, and total system deliverability.

This report addresses these concerns for the natural gas production element of total demand by presenting a historical analysis of the monthly productive capacity of natural gas at the wellhead for 1985 through 1995 and projecting productive capacity for 1996 and 1997. The impact of drilling, well completions, oil and gas price assumptions, and demand on gas productive capacity are integrated into the capacity projections as *low*, *base*, and *high* cases to account for the unpredictable market forces.

The *base* case reflects what would most likely occur if current market trends continue and drilling and production levels perform as they have in the past. The *high* case reflects an increase in the amount of drilling and favorable market conditions, while the *low* case reflects a decrease in drilling due to less favorable market conditions.

Assumptions used in the *Wellhead Productive Capacity Model* are summarized as follows:

- Wellhead gas productive capacity is a function of drilling, which adds new capacity, and production, which lowers existing capacity over time.
- The number of new gas-well completions is a function of drilling, which is influenced by oil and gas prices and production.
- Abandonment of individual conventional and coalbed gas-well completions is captured by decline functions for the group of wells included in a given vintage year for each area.
- Producing characteristics of new conventional and coalbed gas-well completions can be modeled from the characteristics of historical completions.
- Oil-well completions are currently producing at full capacity; therefore, the oil-well gas production rate equals oil-well gas capacity.
- U.S. gas production requirements are allocated to the lower 48 producing areas by month on the basis of 1994's production market share.

This report is based on of historical gas-well drilling and production data from State, Federal, and private sources. In addition to conventional gas-well gas, coalbed gas and oil-well gas are also included. Natural gas production from Alaska is excluded from this report because Alaskan gas does not enter the lower 48 States pipeline system.

For this report, monthly gas-well production data were as obtained on a per completion basis for 14 States and the Gulf of Mexico Outer Continental Shelf (OCS) from Dwight's EnergyData, Inc. (Dwight's). Dwight's data are not available for the entire lower 48 States. Production data on a State basis for the remaining States were obtained from EIA's *Natural Gas Monthly* reports, and the number of gas-well completions were obtained from the American Petroleum Institute (API) drilling statistics. Rig activity data for the Rig Model are obtained from Baker Hughes.

The method used to estimate natural gas productive capacity follows. Details of the methodology are found in Appendix A.

By use of monthly gas-well production data, wells are grouped by vintage (the year a well first produced) for each State or area. A monthly peak production rate was selected each year for every vintage in each State or area. These data were input into the *Wellhead Productive Capacity Model* (Appendix B), where equation parameters were defined and a monthly productive capacity was estimated for each of the vintage years. Vintage-level capacities were summed to obtain the total capacities for each State or area. These were assumed to be the historical productive capacities. The model was used to project *low*, *base* and *high* case productive capacities for 1996 and 1997.

The projected gas production from the model was prorated by State and area on the basis of historical market share as follows. If scheduled gas-well gas production was less than gas-well gas productive capacity in a given State or area, the production required was set equal to the scheduled production. If the required scheduled gas-well gas production was greater than gas productive capacity in a given State or area, the production was set equal to productive capacity. When a State or area did not have adequate capacity to meet scheduled production, the unfilled capacity requirement was prorated to other States or areas that had surplus productive capacity. Surplus gas productive capacity occurs when the gas productive capacity is greater than and the scheduled gas production.

2. Gas Productive Capacity

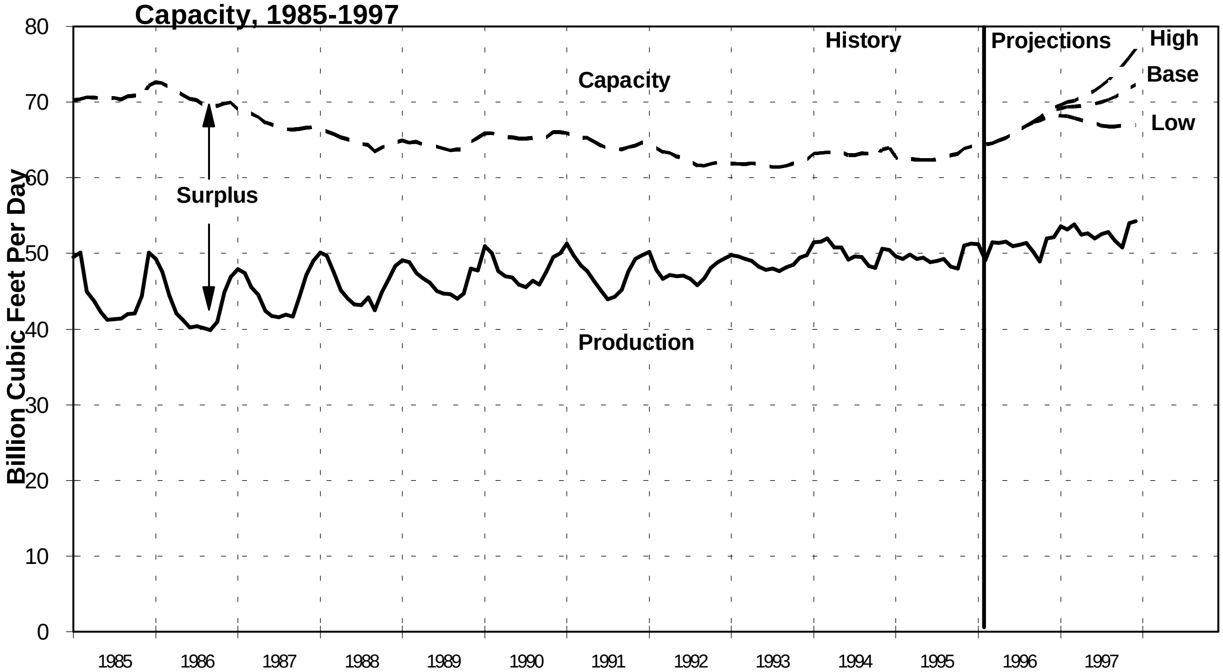
Gas Capacity to Meet Lower 48 States Requirements

The United States has sufficient dry gas productive capacity at the wellhead to meet forecast monthly production requirements through 1997 (Figure 1). Any potential shortfalls in States with surplus productive capacity could probably be met by transfers from those areas with a large surplus productive capacity, such as the Gulf of Mexico Outer Continental Shelf (OCS).

Dry gas is the type of gas generally transported by transmission systems and delivered to customers. *Gross gas* is the full stream volume, including all natural gas plant liquids and nonhydrocarbon gases but excluding lease condensate. In 1994, dry gas production represented 89 percent of the gross gas production in the lower 48 States (Figure 2).

For reporting and analysis, the lower 48 States were grouped into 10 separate producing States or areas on the basis of gas production volumes (Figure 3). Dry gas productive capacity was determined for each of these 10 areas. The quarterly gas production forecast in the Energy Information Administration (EIA), *Short-Term Integrated Forecasting System, Fourth Quarter 1996* {11} was used to determine the lower 48 States' production. This production was prorated into the 10 areas on the basis of their historical market shares (Appendix A). The quarterly production was further prorated into monthly data. If a given area could not meet its historical market share of production, the unmet production requirements were prorated to areas with surplus productive capacity. It was assumed that the pipeline facilities exist to transport this additional production from another supply area to its end market. Recent historical production patterns were used to allocate the projected lower-48 gas production requirements for 1996 and 1997 among States and areas (Figure 4). Appendix A contains a full description of the methodology used for this report.

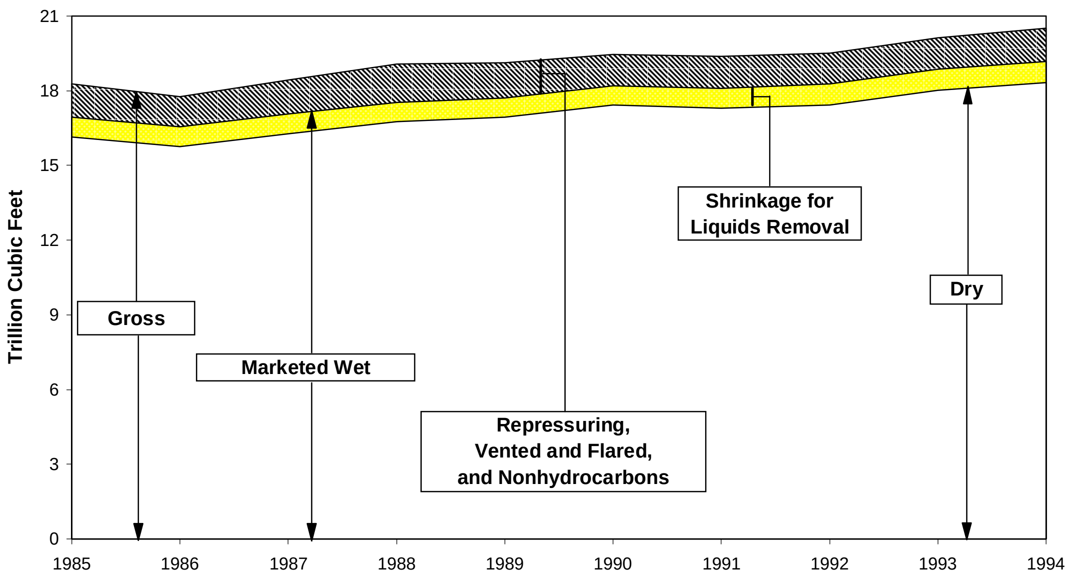
Figure 1. Lower 48 States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

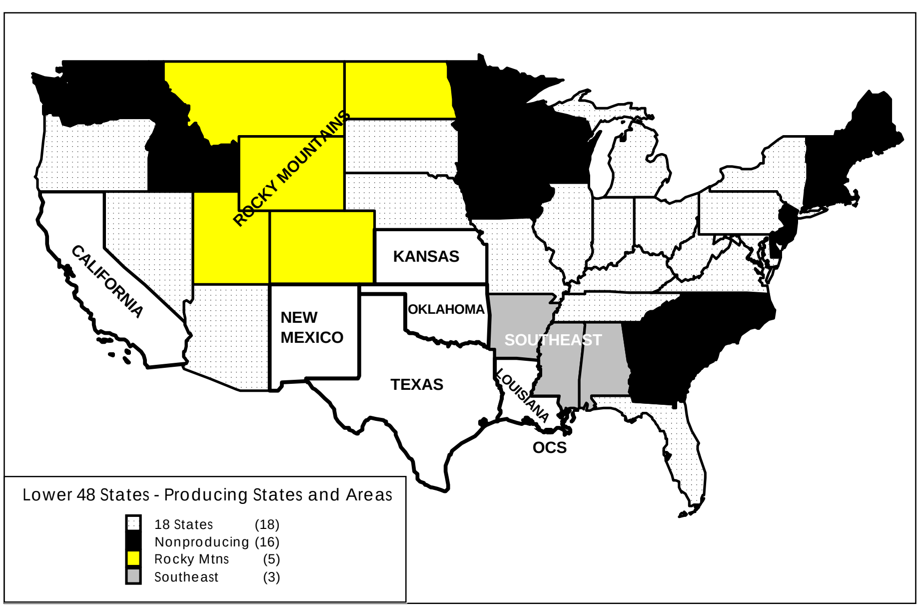
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Figure 2. Lower 48 States Natural Gas Production, 1985-1994



Source: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1985-1994.

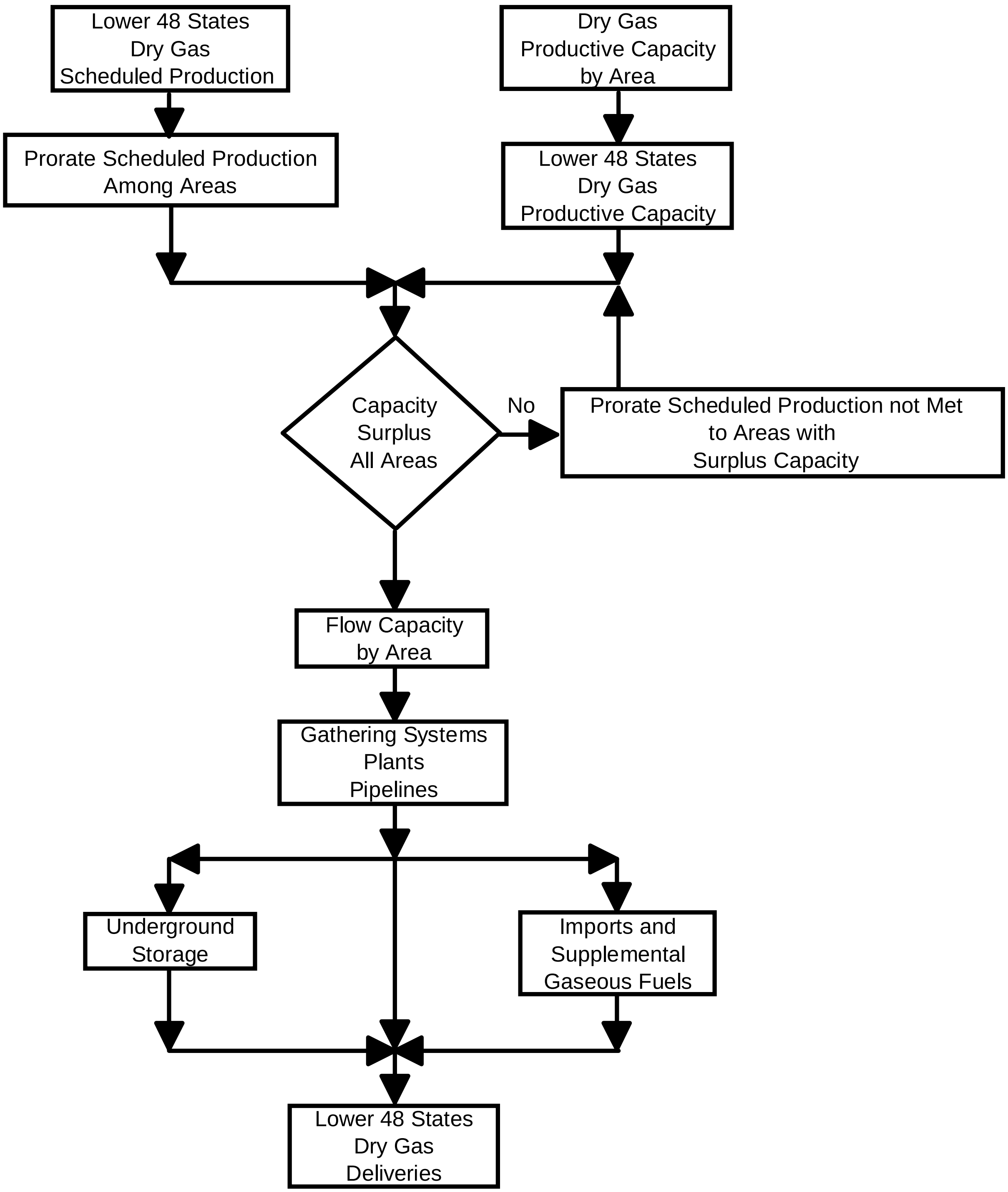
Figure 3. Lower 48 States - Producing States and Areas



Note: The 18 States are Arizona, Florida, Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, Virginia, and West Virginia. Non-producing States are Connecticut, Georgia, Delaware, Idaho, Iowa, Maine, Massachusetts, Minnesota, New Jersey, New Hampshire, North Carolina, Rhode Island, South Carolina, Vermont, Washington, and Wisconsin. Rocky Mountain States are Colorado, Montana, North Dakota, Utah, and Wyoming. Southeast States are Alabama, Arkansas, and Mississippi.

Source: Energy Information Administration, Office of Oil and Gas.

Figure 4. Lower 48 States Productive Capacity and Supply Schematic



Source: Energy Information Administration, Office of Oil and Gas.

Historical Data

Dry Gas Productive Capacity Trends

Historical monthly gas production and productive capacity for the lower 48 States for the months of January, June, and December are presented in Table 1.[1] January and December represent the typical peak winter months, and June represents a non-heating season.

Dry gas productive capacity in the lower 48 States substantially exceeded production throughout the 1980's. The lower 48 States' surplus capacity was more than 20 billion cubic feet per day through December 1986. However, gas capacity began declining in 1986 as drilling and new well completions rapidly declined. In 1995, surplus capacity was 12.9 billion cubic feet per day in December of that year.

The rapid decline in drilling and new well completions was caused by reduced prices. The wellhead price for natural gas declined from 1985 to 1986 and then began fluctuating seasonally after 1987 (Figure 5).

Gas Production

Total gross gas production (composed of gas-well and oil-well gas) from 1985 through 1994 is shown in Figure 6. Gas production from oil wells was stable over this time period, although oil production declined. Increases in producing gas-oil ratios roughly compensated for the declines in oil production. In 1994, gas production from oil wells was 16 percent of total gas production in the lower 48 States. If oil production declines in 1995, 1996, and 1997, as expected, gas production from oil wells will also decline if the producing gas-oil ratio stays at its 1994 level. The share of total gross production from gas wells increased from 79 percent in 1986 to 84 percent in 1994

The dry natural gas production contribution from the major gas-producing States and areas is shown by Figure 7. The market share of production among States has been fairly stable from 1985 through 1994. The two largest gas-producing areas are the Gulf of Mexico OCS and Texas. Together these areas produce over one-half of the dry gas in the lower 48 States. The Gulf of Mexico has made the largest contribution to meeting major seasonal swings in demand. Other significant natural gas-producing States include Oklahoma, Louisiana, New Mexico, and Kansas. Chapter 3 reviews State and area gas production in detail.

Monthly gas production varies seasonally. Normally, production is highest in the months of January or February (because of high heating demand), substantially lower in June, and relatively higher in December. However, the minimum monthly production rate for a given year may fall in other months, such as September, when there is neither a large cooling nor heating demand.

Coalbed gas was treated separately in this report for New Mexico and the Southeast and Rocky Mountains areas (Figure 8). These are the three major coalbed gas-producing areas. Coalbed gas production has increased 1 percent per year as a percentage of the lower 48 States' gas production since 1990. Coalbed gas production was 5 percent of the lower-48 total gas produced in 1994.

Gas Prices

The average real wellhead value of natural gas peaked in 1983 at $3.75 (in constant 1994 dollars) per thousand cubic feet{12}, dropped sharply in 1986, and continued to decline to $1.76 per thousand cubic feet in 1991 (a 53 percent drop over eight years). The average price increased in 1994 to $1.88.{13} For comparison, real domestic crude oil prices dropped from $37.87 per barrel in 1983 to $13.19 in 1994, a 65 percent drop.{12} Given the lower prices and consequent decrease in drilling, it is understandable that wellhead productive capacity declined to values closer to gas production requirements from 1986 through 1994.

Projections

Dry Gas Productive Capacity and Production

EIA projects the natural gas wellhead productive capacity for the lower 48 States by using the *Wellhead Productive Capacity Model*. For a description of the model and its methodology, see Appendix B. The model estimates the last year of historical production and productive capacity and generates a 2-year projection of production and wellhead gas capacity. To account for unpredictable market forces and changing drilling activity levels, gas productive capacity projections are formulated for *low*, *base*, and *high* cases. The *base* case reflects what would most likely occur if current market trends continue and drilling and production levels continue to perform as they have performed in the past. The *high* case reflects an increase in the amount of drilling under more favorable market conditions, while

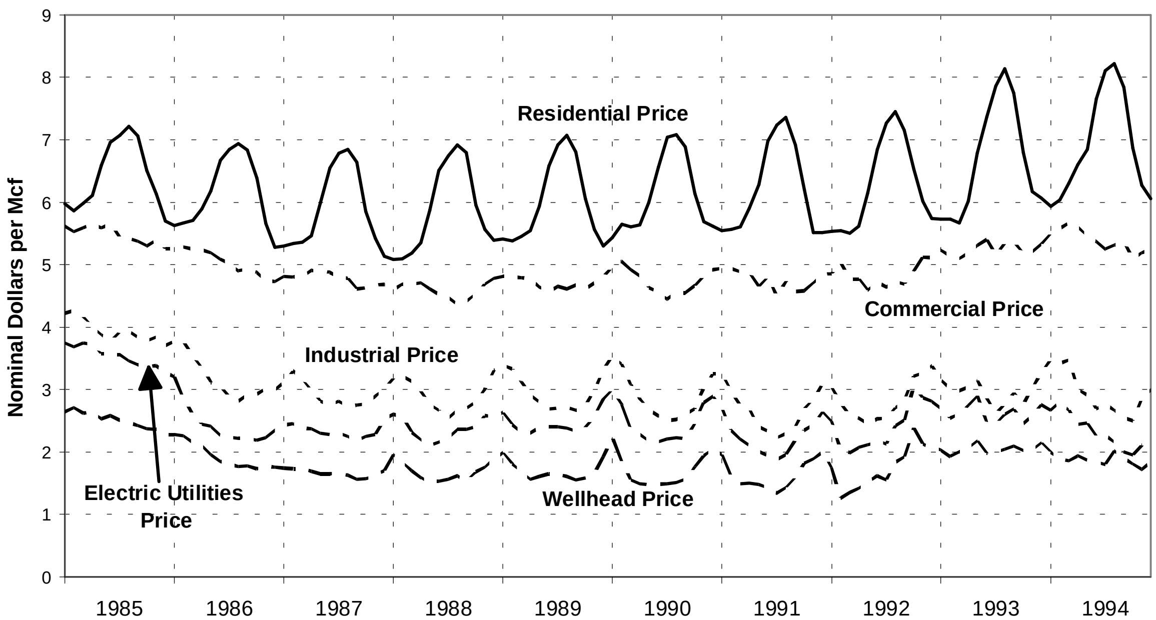
[1]Production and capacity for all 12 months can be obtained from the authors.

Table 1. Lower 48 States Dry Gas Production and Wellhead Productive Capacity, 1985-1995 (Billion Cubic Feet Per Day)

		Dry Gas Productive Capacity				
Month-Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	49.5	61.3	9.0	70.3	20.8	70.5
Jun-85	41.2	61.3	9.2	70.4	29.2	58.5
Dec-85	50.1	62.9	9.2	72.1	22.1	69.4
Jan-86	49.3	62.8	9.8	72.6	23.3	67.9
Jun-86	40.3	61.4	9.0	70.4	30.2	57.2
Dec-86	46.9	61.1	8.8	70.0	23.0	67.1
Jan-87	47.9	60.1	9.0	69.1	21.2	69.3
Jun-87	41.8	58.2	8.8	67.0	25.3	62.3
Dec-87	49.0	58.0	8.7	66.6	17.6	73.6
Jan-88	50.1	57.6	8.8	66.4	16.3	75.4
Jun-88	43.2	56.0	8.8	64.8	21.6	66.7
Dec-88	48.4	56.1	8.5	64.7	16.3	74.8
Jan-89	49.1	56.2	8.8	64.9	15.8	75.6
Jun-89	45.0	55.7	8.4	64.1	19.1	70.3
Dec-89	47.8	57.4	7.9	65.3	17.5	73.2
Jan-90	50.9	57.2	8.7	65.9	14.9	77.3
Jun-90	45.8	56.8	8.4	65.2	19.3	70.3
Dec-90	50.0	57.6	8.4	66.0	16.0	75.8
Jan-91	51.3	57.5	8.4	65.9	14.6	77.9
Jun-91	45.1	56.0	8.3	64.3	19.2	70.1
Dec-91	49.8	56.4	8.3	64.7	14.9	77.0
Jan-92	50.2	55.7	8.6	64.3	14.1	78.1
Jun-92	47.1	54.2	8.4	62.6	15.5	75.3
Dec-92	49.3	53.9	8.2	62.1	12.8	79.5
Jan-93	49.8	53.7	8.1	61.9	12.1	80.5
Jun-93	47.9	53.5	8.1	61.6	13.8	77.6
Dec-93	49.7	54.5	7.9	62.4	12.7	79.7
Jan-94	51.5	55.1	8.0	63.2	11.7	81.4
Jun-94	49.2	55.1	7.9	63.0	13.8	78.1
Dec-94	50.5	56.0	8.0	64.0	13.5	78.9
Jan-95[a]	49.6	54.7	7.9	62.6	13.0	79.3
Jun-95[a]	48.8	54.4	7.9	62.3	13.5	78.4
Dec-95[a]	51.2	56.4	7.7	64.1	12.9	79.9

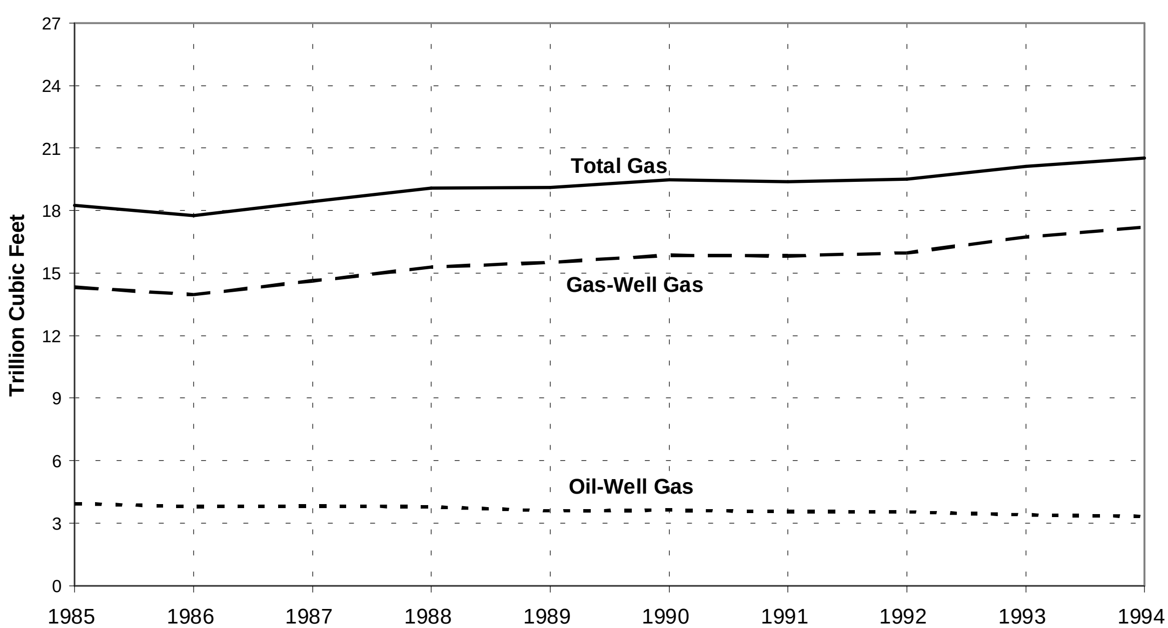
[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196.

Figure 5. Natural Gas Price by Category, 1985-1994



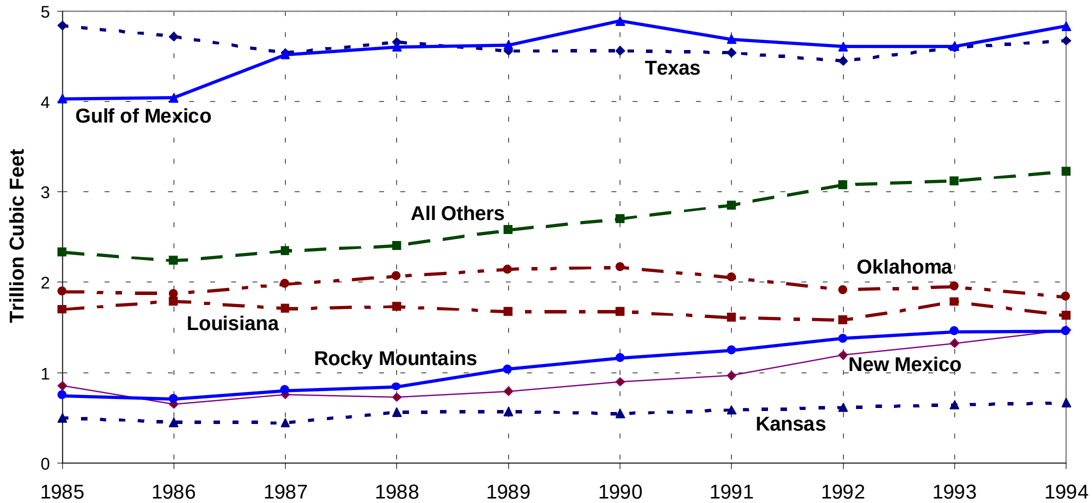
Source: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(96/02).

Figure 6. Lower 48 States Gross Natural Gas Production by Type, 1985-1994



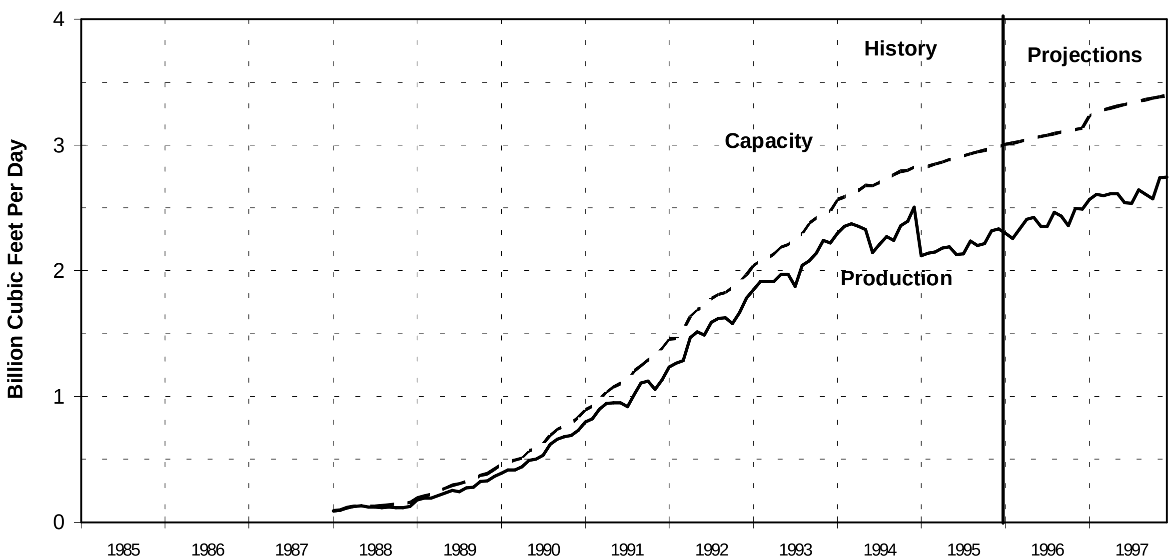
Source: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1985-1994.

Figure 7. Dry Natural Gas Production from Lower 48 Producing States, 1985-1994



Note: State production for Texas and Louisiana does not include Gulf of Mexico OCS production
Sources: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1985-1994. Data for Texas, Louisiana, and Gulf of Mexico OCS are from Energy Information Administration, Office of Oil and Gas.

Figure 8. Lower 48 States Dry Coalbed Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only.
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C11016. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

the *low* case reflects a decrease under less favorable conditions. The model results are listed in Table 2.

In December 1995, the wellhead productive capacity of the lower 48 States was 64.1 billion cubic feet per day of dry natural gas. For the lower 48 States, the model projects the following:

- In the *low* case projection, dry gas productive capacity will increase 5 percent to 67.0 billion cubic feet per day in December 1997.
- In the *base* case projection, productive capacity will increase 13 percent to 72.3 billion cubic feet per day in December 1997.
- In the *high* case, productive capacity increases 20 percent from the December 1995 level, reaching 77.0 billion cubic feet per day in December 1997.

For surplus capacity in the lower 48 States:

- In the *low* case, the surplus capacity declines from 12.9 billion cubic feet per day in December 1995 to 12.7 billion cubic feet per day in December 1997.
- In the *base* case, surplus capacity increases to 18.1 billion cubic feet per day in December 1997.
- In the *high* case, the surplus capacity increases to 22.7 billion cubic feet per day in December 1997.

Gas productive capacity should be adequate to meet the projected monthly gas production requirements of the lower 48 States through December 1997, even in the *low* case.

New Well Completions

Gas productive capacity is increased by new gas-well completions. If there had been no new gas-well completions projected after 1994, the surplus capacity would have gone from 12.9 billion cubic feet per day in December 1995 to zero by December 1996. With no new completions, productive capacity would not have been adequate to meet the forecast production requirements. Gas-well completions must be added continuously to sustain an adequate productive capacity.

To project gas productive capacity, a projection of new gas-well completions is required. The projection of new well completions is based on a projection of rigs running and an estimate of completions per rig. Forecasts of the total drilling rigs were obtained from the EIA Drilling Rig Model. This model generates monthly rig counts on the basis of oil and gas revenues which are derived from production and price data appearing in the EIA's *Short Term Energy Outlook* (STEO). The Drilling Rig Model is described in Appendix A.

Gas-well completions dropped from 17,639 in 1985 to 11,356 in 1986, with even fewer completions in 1987 (Figure 9). Despite this large decline, the general improvement in the average productive capacity of new completions precluded a serious loss of surplus capacity (Figure 1).

Gas-well completions added for the 2-year period 1996 through 1997 are estimated to be 21,694 for the *low* case, 25,451 for the *base* case, and 28,752 for the *high* case (Figure 9). The larger number of completions yields a dry gas productive capacity for the *high* case in December 1997 that is 77.0 billion cubic feet per day, (Table 2) or 7 percent higher than the 72.3 billion cubic feet per day in the *base* case. Gas production requirements were assumed to be the same in both cases.

A new gas-well completion is estimated to add about one million cubic feet per day of capacity (Appendix D). For the *low* case in 1997, the gas-well gas productive capacity is estimated to decline about 1.0 billion cubic feet per day (December 1996 to December 1997). To avert this decline, 1,000 gas-well completions need to be brought on production in 1997.

For the *low*, *base*, and *high* cases, the corresponding gas-well completions were estimated primarily as a function of gas price and production. The 1997 gas prices for the three cases were respectively $1.72, $1.85, and $2.15 per thousand cubic feet, as shown in the Short-Term Integrated Forecasting System, Fourth-Quarter 1996{11}. The actual gas prices were $1.88 per thousand cubic feet in 1994{13} and $1.59 in 1995{11}.

The newer gas-well completions contribute most of the productive capacity in the lower 48 States. Wells less than three years old contributed 42 percent of the productive capacity in the lower 48 States in December 1994. Wells less than 2 years old provided 35 percent, while wells completed that year provided 22 percent (Figure 10).

Table 2. Lower 48 States Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Billion Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
			Low Case Projection			
Jan-96	51.2	56.5	7.8	64.2	13.0	79.8
Jun-96	50.9	58.0	7.8	65.8	14.8	77.4
Dec-96	52.2	60.7	7.6	68.4	16.2	76.3
Jan-97	53.6	60.6	7.6	68.2	14.6	78.6
Jun-97	52.0	59.8	7.4	67.2	15.2	77.3
Dec-97	54.2	59.7	7.3	67.0	12.7	81.0
			Base Case Projection			
Jan-96	51.2	56.5	7.8	64.2	13.0	79.8
Jun-96	50.9	58.0	7.8	65.8	14.8	77.4
Dec-96	52.2	61.1	7.8	69.0	16.8	75.6
Jan-97	53.6	61.3	7.8	69.1	15.5	77.5
Jun-97	52.0	62.0	7.7	69.7	17.7	74.5
Dec-97	54.2	64.6	7.7	72.3	18.1	75.0
			High Case Projection			
Jan-96	51.2	56.5	7.8	64.2	13.0	79.8
Jun-96	50.9	58.0	7.8	65.8	14.8	77.4
Dec-96	52.2	61.3	8.0	69.3	17.2	75.3
Jan-97	53.6	61.6	8.0	69.6	16.0	77.0
Jun-97	52.0	63.5	8.0	71.5	19.5	72.7
Dec-97	54.2	69.0	8.0	77.0	22.7	70.5

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996 and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

Gas Productive Capacity Issues

Demand

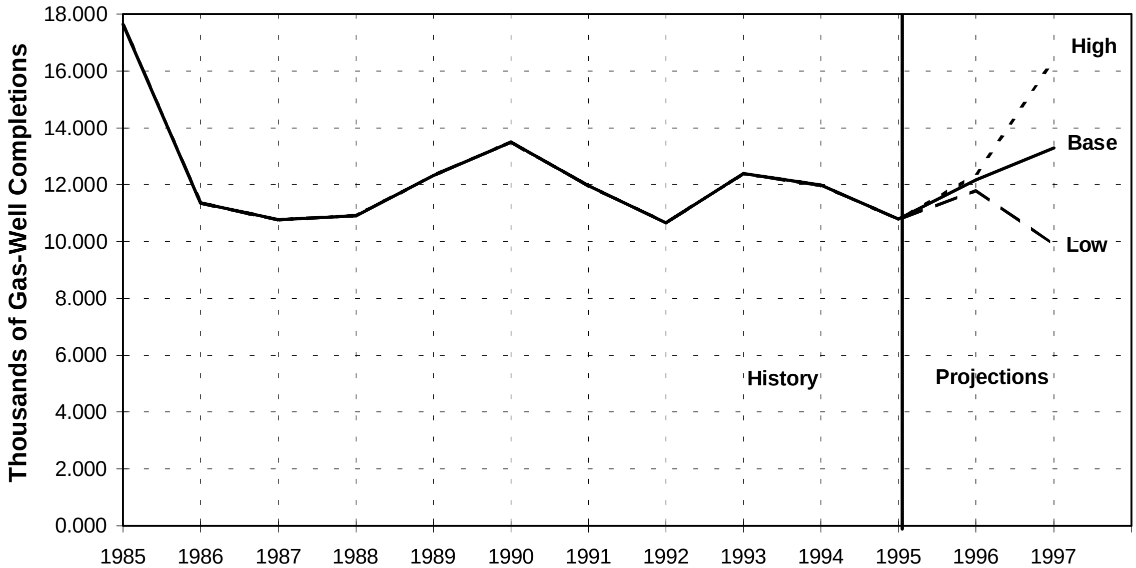
Peak-day demand may be twice the annual average-day demand. Peak-day demand usually occurs in December, January, or February during very cold weather. The cold weather, while increasing gas demand, may also decrease potential supply because of weather-related production and transportation problems.[2]

Peak-day demand cannot be met by increasing gas production at the wellhead and should not be expected to be met by production in the future. The National Petroleum Council {14} estimated that firm peak-day consumption in 1991 reached 102 billion cubic feet per day. The period from December 23 to December 27, 1989, was extraordinarily cold and demand may well have approached this peak rate.

To better serve its customers, the natural gas industry has developed methods to meet peak demand, such as delivery from gas storage facilities (70 billion cubic feet per day){15} and peak shaving facilities (3 billion cubic feet per day).{14} Some projects have recently been

[2]For more information about this subject see Energy Information Administration, Service Report SR/OG/91-01 and *Oil and Gas Journal*, March 5, 1990, pp.17-20.

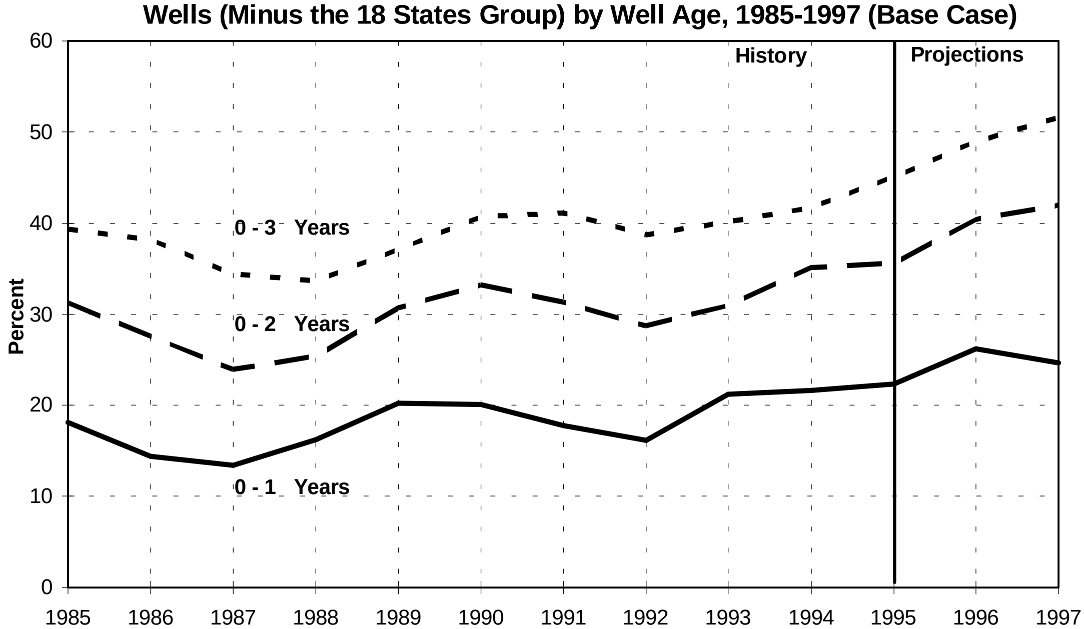
Figure 9. Lower 48 States Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on EIA's Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 10. Percent of Total Wellhead Productive Capacity of Lower 48 States Gas Wells (Minus the 18 States Group) by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: M GASCAP94 C110196.

placed in service and others are proposed that allow greater access to supply areas and support increasing natural gas consumption.

It could be argued that in periods of high gas demand, price increases at the wellhead could both increase supply quantities and decrease consumption until they balance. Over a sufficient period of time this is true. However, in the very short term (days), average wellhead prices are relatively unresponsive to demand, although, commercial, industrial, and electric utility gas prices normally increase during periods of high seasonal demand (Figure 5). The vast majority of gas is covered by 30-day or longer contracts. Therefore, if there is a sudden large increase in gas demand, there is not an accompanying sudden, large increase in the average price of gas at the wellhead. However, small volumes of gas may sell at very high prices on the spot market.

Effective gas demand in peak periods is typically lowered by reducing deliveries to customers with interruptible contracts or by customers with fuel-switching capability responding to higher gas prices by switching to another fuel. A price increase would have little impact on reducing residential gas requirements. It is residential heating or cooling demand that is most likely to have a sudden upward surge related to weather. Residential consumers used 5.9 times as much gas in December 1993 as they did in August 1993 and 5.2 times as much gas in December 1994 as they did in August 1994.{16}

Because cost-of-service pricing lowers the unit cost of gas during periods when large volumes are being delivered, the residential cost of gas per thousand cubic feet actually drops in December, while the wellhead price of gas increases.{16} Figure 5 shows the relationship of wellhead price to residential, commercial, industrial, and electric utility prices for 1985 through 1994. Therefore, small increases in the average price of natural gas at the wellhead do not effectively dampen weather-related residential gas requirements in the short term.

Deliverability

The existence of a high gas productive capacity at the wellhead does not mean that it could actually be produced and delivered. Deliverability is always equal to or less than wellhead productive capacity. Deliverability takes into account restrictions imposed by pipeline capacity, contract, or regulatory bodies. Even with a large surplus dry gas productive capacity, there can be short-term regional gas supply problems such as occurred in December 1983 and December 1989.[3]

In order to meet peak-month or peak-day demand, the pipeline system must also have adequate deliverability to the final destination. Pipeline systems must have adequate diameters, properly spaced compressors, and adequate interconnections between pipelines. Gas pipeline systems must be optimized to transport gas efficiently from any well to wherever in the lower 48 States where the need might arise.

Productive capacity and deliverability can be compared by using the data collected by the Natural Gas Supply Association (NGSA) in its *NGSA Survey on 1995 Natural Gas Field Deliveries* & *Productive Capacity*.{17} The data on connected gas-well capacity as of January 1, 1995, which is equivalent to deliverability into the pipeline system, were collected on an operator basis for seven lower-48 regions. The survey covered 77 percent of the production for the Offshore Gulf Coast, the highest for any region in the survey. The ratio of the NGSA 1995 connected gas field capacity to the annual 1995 field deliveries was 1.09. In other words, deliverability was 9 percent higher than annual production. The equivalent deliverability for all Offshore Gulf Coast operators was 15 billion cubic feet per day if the NGSA surveyed operators are representative of all operators in this region.

For the month of January 1995, it was estimated that 87 percent of the productive capacity at the wellhead could be delivered into the pipeline system. This was obtained by dividing the January 1995 deliverability of 55 billion cubic feet per day (determined by scaling up the NGSA connected-gas-well capacity){17} by the January 1995 dry productive capacity at the wellhead of 63 million cubic feet per day.

During the 1980's and most recently with FERC Order 636 in 1992, major changes have occurred in regulations, contracts, interconnections between trunklines, access to transportation, and markets. These changes have introduced a much greater degree of flexibility and responsiveness in the natural gas industry. This flexibility makes it likely that a higher percentage of the productive capacity can be delivered. More gas can get from where it is produced to where it is needed. However, in some cases, pipeline capacity may limit gas deliverability.

[3]For more information on this subject see American Oil & Gas Reporters. May 1984, pp. 15-25; *Energy Informationa Administration, Service Report* SR/OG/9/01; and *Oil and Gas Journal*, March 5, 1990, pp. 17-20.

Weather’s Effect on Deliverability

The December 1989 average-day production of dry gas was only 47.8 billion cubic feet per day (Table 1), which was practically the same as in December 1988. However, some regional peak-day requirements for production in late December 1989 were not met. Some customers with firm contracts had their gas supplies curtailed. This was in large part due to weather-related production problems that are not likely to soon occur again with the same severity. Weather-related increases in gas production requirements and decreases in supply also occurred in December 1983. In December 1983, the problems were most severe in south Texas. In December 1989, they were most severe in the Gulf of Mexico OCS.

One problem that is associated with the handling of natural gas is the phenomenon of a production line or well "freezing up." This problem occurs when water vapor and hydrocarbon vapors combine to form snow-like substances, called hydrates. Under suitable pressure conditions, hydrates may be formed at temperatures well above the freezing point of water. One of the problems in handling natural gas is the prevention of the formation of hydrates and their removal once formed.

The proper winterization of wells, pipelines, and gas processing facilities is a relatively straightforward and inexpensive process. Operators in south Texas prepared for severe weather after December 1983 and were not severely affected in December 1989.

Interruptions in regional supply can cause a peak production requirement in other areas. For example, a storm in the Gulf of Mexico OCS, such as hurricane Andrew in August 1992, damaged 243 producing sites in the Gulf. Some 5 percent of the Nation’s gas supply, or about 2.5 to 2.75 billion cubic feet per day was abruptly shut in. A month and-a-half later, in early October, 750 to 800 million cubic feet of production was still shut in. Needed gas was supplied to consumers from other areas or from storage during part of this time.

Gas Storage

Gas storage is a vital part of the natural gas industry. Stored gas provides a source for reliable deliveries during periods of heavy demand. Storage also enables greater system efficiency by allowing more stable production and transmission flows.

Storage withdrawals and peak shaving were used successfully to prevent gas supply curtailment in the extraordinarily high peak-day demand period in December 1989. Sufficient dry gas productive capacity will exist during the years 1995 through 1997 to increase the underground natural gas storage inventory needed. Gas storage requirements can be met by maintaining gas production closer to gas productive-capacity throughout the year. Increased use of storage reduces the need for excess productive capacity, thus promoting improved economic efficiency in production.

Imports

Imports have become an increasingly important part of the domestic gas supply picture. Reliance on imported gas has more than doubled in less than a decade. In 1985, net imports made up 5 percent (894 billion cubic feet) of the total gas demand requirements. In 1994, net imports supplied 12 percent (2,462 billion cubic feet) of the total gas demand requirements.

The net imported gas volume was 6.7 billion cubic feet per day in 1994. Without imported gas, the surplus capacity would be reduced. The surplus capacity in 1994 was only 14 billion cubic feet per day. If demand continues to rise without an increase in gas-well completions, surplus capacity may not be able to cover the loss of imported gas.

3. Producing Areas

This section of the report details the natural gas wellhead productive capacity by State or area where Dwight's gas-well gas production data are available. From these data, individual studies are made for each of six States: California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and the Gulf of Mexico Federal Offshore Outer Continental Shelf (OCS).

The remaining Dwight's data are combined into 3 groups of States (Figure 3). Five states are grouped together as *Rocky Mountains*: Colorado, Montana, North Dakota, Utah, and Wyoming. Three states are combined as the *Southeast* group, consisting of Alabama, Arkansas, and Mississippi. The third group is made up of *18 States*: 3 States with Dwight's data–Michigan, Nebraska, and South Dakota and 15–Arizona, Florida, Illinois, Indiana, Kentucky, Maryland, Missouri, Nevada, New York, Ohio, Oregon, Pennsylvania, Tennessee, Virginia, and West Virginia-for which no Dwight's data are available.

Each State or group of States has its own unique, initially scheduled monthly gas production rate for January 1995 set to the same values for the *low, base*, and *high* cases. However, the actual production rate in an area will be less than its initially scheduled production rate if its scheduled production rate exceeds its gas productive capacity. Scheduled gas production is the production demand for the United States taken from the Energy Information Administration's Short-Term Integrated Forecasting System, Fourth Quarter 1996, {11} and prorated among the States and areas.

For each State or area where the scheduled production exceeds the gas productive capacity, the deficit capacity (the negative difference between capacity and scheduled production) is rescheduled to States and areas with surplus capacity. The production for these deficit capacity States will be greater in the *base* and *high* cases because there will be more well completions. The larger number of well completions adds more capacity and reduces or eliminates the deficit capacity.

For States or areas where the scheduled production does not exceed capacity, the surplus capacity (the positive difference between capacity and scheduled production) is used to replace the deficit capacity of the States and areas with deficit capacities. For these surplus capacity States, the production rate will be highest in the *low* case because there is a larger deficit capacity to make up.

Gulf of Mexico OCS

The Gulf of Mexico OCS is a prolific natural gas producer with large seasonal variations in producing rate. In 1994, more than a quarter of the lower 48 States' dry gas production came from this area. Mobile Block 823 producing 70 Bcf, was the largest OCS natural gas producer in 1994. Garden Banks 236 was the second largest producer making 69 Bcf, and Matagorda Island 623, the third largest producer, producing 64 Bcf.

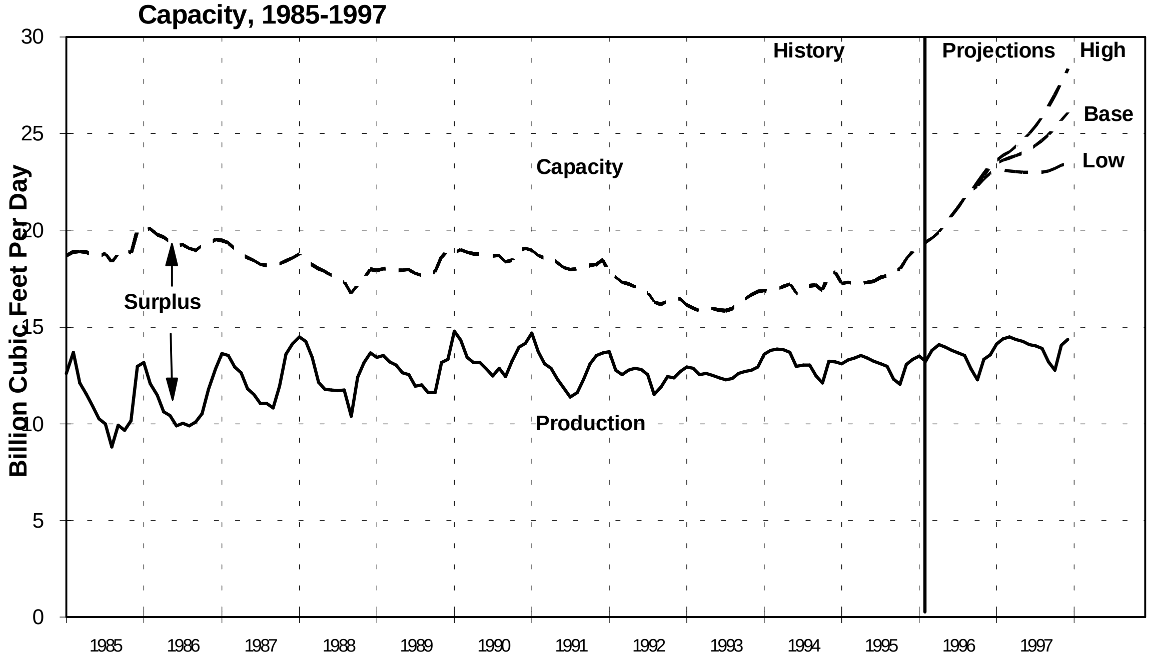
Surplus capacity was adequate from 1985 through 1995. Future projections show increases for the *low*, *base*, and *high* cases.

Figure 11 shows the dry gas production rate and wellhead productive capacity from 1985 through 1995, with projections through 1997. The January, June, and December historical production rates and capacities are presented in Table 3. Dry gas production and wellhead productive capacity projections are shown by Table 4.

Figure 12 shows the number of gas-well completions added during each year from 1985 through 1995 and projected through 1997. There is an increase in the Gulf of Mexico completions for 1996 and a decrease in 1997. In 1996, the number of drilling rigs in the Gulf of Mexico OCS increased. An increase in the number of completions resulted, because the number of completions is a function of the number of rigs. Lower-48 rigs are forecast to increase in 1997 for the *base* and *high* cases and decrease for the *low* case. After taking into account the completion (per rig and area distribution factors the Gulf of Mexico OCS completions are expected to, increase in 1997 for the *high* case and decrease for the *base* and *low* cases. Current information indicates that several large platforms are scheduled to come on production during 1996.

The initial flow rate per well completion for the Gulf of Mexico is about eight million cubic feet per day (Appendix D). Most reservoirs in the Gulf of Mexico have high permeabilities and are water-drive reservoirs. This means that the reservoir can sustain a high flow rate throughout most of its producing life. However, the recovery efficiency is generally less than the recovery efficiency for reservoirs with other types of drive mechanisms. It is common for a Gulf of Mexico OCS gas-well completion to produce eight billion cubic feet of gas over its life.

Figure 11. Gulf of Mexico OCS Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 3. Gulf of Mexico OCS Dry Gas Production and Wellhead Productive Capacity, 1985-1995
(Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	12,591	17,317	1,373	18,690	6,099	67.4
Jun-85	10,261	17,123	1,539	18,662	8,401	55.0
Dec-85	12,969	18,493	1,530	20,023	7,054	64.8
Jan-86	13,177	18,461	1,585	20,046	6,869	65.7
Jun-86	9,891	17,752	1,460	19,212	9,321	51.5
Dec-86	12,823	18,038	1,489	19,527	6,704	65.7
Jan-87	13,620	18,066	1,416	19,482	5,862	69.9
Jun-87	11,532	17,127	1,317	18,444	6,912	62.5
Dec-87	14,124	17,329	1,252	18,581	4,457	76.0
Jan-88	14,490	17,526	1,254	18,780	4,290	77.2
Jun-88	11,750	16,385	1,309	17,694	5,944	66.4
Dec-88	13,659	16,681	1,314	17,995	4,336	75.9
Jan-89	13,439	16,644	1,286	17,930	4,491	75.0
Jun-89	12,535	16,757	1,224	17,981	5,446	69.7
Dec-89	13,346	17,886	1,085	18,971	5,625	70.3
Jan-90	14,793	17,622	1,220	18,842	4,049	78.5
Jun-90	12,827	17,533	1,184	18,717	5,890	68.5
Dec-90	14,153	17,852	1,228	19,080	4,927	74.2
Jan-91	14,695	17,681	1,301	18,982	4,287	77.4
Jun-91	11,846	16,767	1,314	18,081	6,235	65.5
Dec-91	13,677	17,056	1,434	18,490	4,813	74.0
Jan-92	13,740	16,471	1,325	17,796	4,056	77.2
Jun-92	12,791	15,664	1,297	16,961	4,170	75.4
Dec-92	12,721	15,239	1,233	16,472	3,751	77.2
Jan-93	12,928	14,792	1,353	16,145	3,217	80.1
Jun-93	12,384	14,499	1,377	15,876	3,492	78.0
Dec-93	12,936	15,462	1,378	16,840	3,904	76.8
Jan-94	13,605	15,346	1,538	16,884	3,279	80.6
Jun-94	12,961	15,185	1,548	16,733	3,772	77.5
Dec-94	13,202	16,206	1,632	17,838	4,636	74.0
Jan-95[a]	13,086	15,593	1,652	17,245	4,159	75.9
Jun-95[a]	13,229	15,627	1,744	17,371	4,142	76.2
Dec-95[a]	13,319	17,171	1,743	18,914	5,595	70.4

[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C11016. Productive Capacity: Model GASCAP94 C110196.

Table 4. Gulf of Mexico OCS Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
			Low Case Projection			
Jan-96	13,496	17,395	1,766	19,161	5,665	70.4
Jun-96	13,783	18,993	1,776	20,769	6,986	66.4
Dec-96	13,587	21,140	1,821	22,961	9,374	59.2
Jan-97	14,141	21,214	1,819	23,033	8,892	61.4
Jun-97	14,076	21,154	1,844	22,998	8,922	61.2
Dec-97	14,567	21,611	1,846	23,457	8,890	62.1
			Base Case Projection			
Jan-96	13,496	17,395	1,766	19,161	5,665	70.4
Jun-96	13,783	18,993	1,776	20,769	6,986	66.4
Dec-96	13,578	21,351	1,901	23,252	9,674	58.4
Jan-97	14,127	21,538	1,928	23,466	9,339	60.2
Jun-97	14,076	22,263	1,907	24,170	10,094	58.2
Dec-97	14,342	24,127	1,953	26,080	11,738	55.0
			High Case Projection			
Jan-96	13,496	17,395	1,766	19,161	5,665	70.4
Jun-96	13,783	18,993	1,776	20,769	6,986	66.4
Dec-96	13,571	21,447	1,961	23,408	9,837	58.0
Jan-97	14,127	21,675	1,970	23,645	9,518	59.7
Jun-97	14,076	22,990	2,007	24,997	10,921	56.3
Dec-97	14,165	26,315	2,039	28,354	14,189	50.0

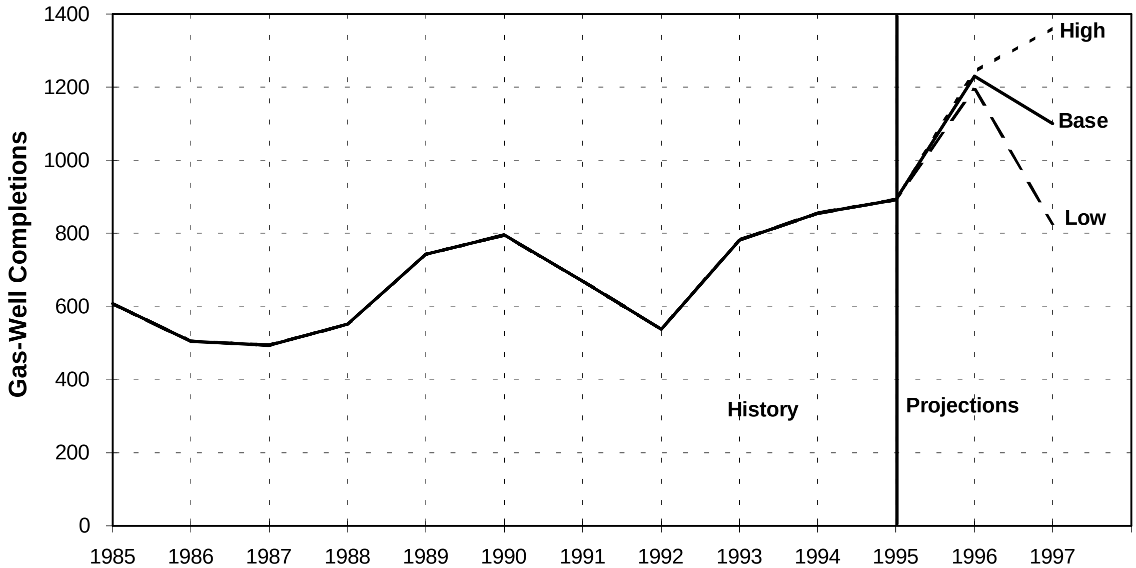
Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

Figure 13 shows the percent of the Gulf of Mexico OCS gas-well productive capacity in December of each year by age of the well. Gas-well completions that have been producing for less than one year contributed from 17 to 35 percent of the productive capacity from 1985 through 1995.

The gap between the capacity and production curves was continuing to narrow from 1985 through 1993. After 1993, new discoveries have reversed this trend. Several deep water projects are scheduled to commence production in 1996 and 1997. These projects, such as Shell's Ram Powell tension leg platform and their subsea Mensa project are reversing the declining surplus capacity trend for the OCS area.

The OCS area provides surplus capacity to meet major seasonal swings in the lower 48 States gas requirements. The future for this area to meet this role looks bright, especially if successful deep water projects continue to add adequate gas-well completions.

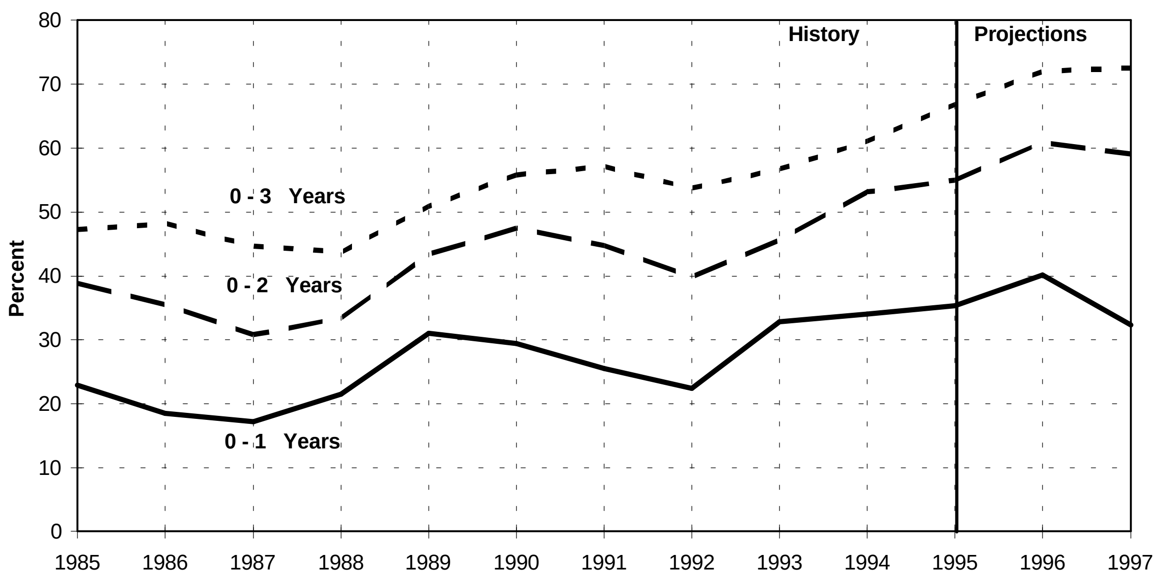
Figure 12. Gulf of Mexico OCS Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 13. Percent of Total Wellhead Productive Capacity of Gulf of Mexico OCS Gas Wells by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Texas (Excluding Gulf of Mexico OCS)

Texas gas production amounted to over a quarter of the lower 48 States dry gas production in 1994. Gas-producing zones range from high permeability, water-drive formations to low permeability "Tight Gas" reservoirs. The two largest gas-producing areas in 1994 in the State were the Carthage (184 Bcf) and the Panhandle West (163 Bcf) fields.

Figure 14 shows the dry gas production rate and wellhead productive capacity from 1985 through 1994, with projections through 1997. The January, June, and December production rates and capacities are presented in Tables 5 and 6. Productive capacity began a very pronounced downturn beginning in 1986. After 1986, surplus capacity began to diminish (Figure 14). Consequently, capacity utilization increased from 1986 through 1995 (Table 5). The surplus capacity is projected to continue to increase in 1996 and 1997 for the base and high cases. Compared with the OCS, surplus capacities have not shown large increases in June. This reflects the fact that production requirements for Texas gas are less seasonal than for the Gulf of Mexico OCS.

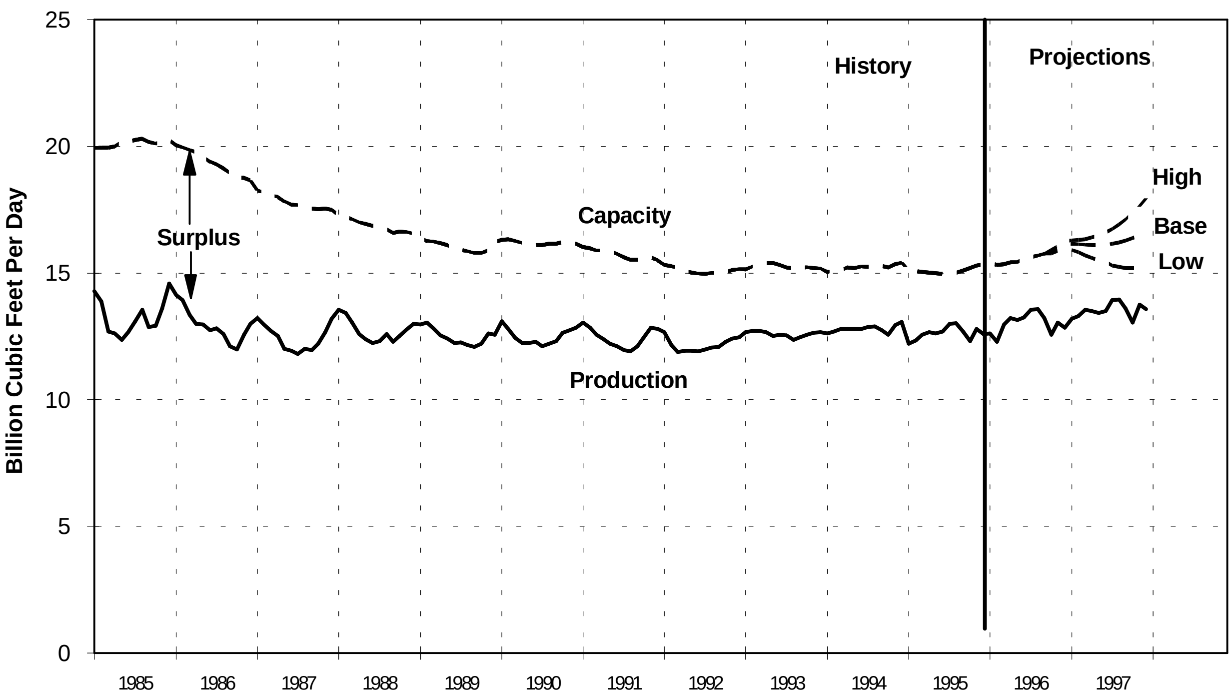
Figure 15 shows the number of producing gas-well completions added during each year from 1985 through 1994, with projections through 1997. The number of gas-well completions declined sharply in 1986.

Initial flow rates for Texas wells range from high to relatively low. The average initial flow rate per well in Texas has been about one million cubic feet per day for the last few years (Table D1).

Figure 16 shows the percent of the Texas gas-well gas productive capacity for each year by age of well. Well completions that have been producing gas for less than one year contributed 25 percent of the gas-well gas productive capacity in 1995.

Figure 17 shows a comparison of the maximum daily rate monthly determined by the Texas Railroad Commission (TRC) and the gross gas-well gas productive capacity estimated in this study. The magnitude of the maximum daily rate as determined by TRC from the G-10 tests is higher than the productive capacity estimated in this report.

Figure 14. Texas (Excluding Gulf of Mexico OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 5. Texas (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity, 1985-1995 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	14,287	16,531	3,398	19,929	5,642	71.7
Jun-85	12,657	16,757	3,398	20,155	7,498	62.8
Dec-85	14,589	16,816	3,421	20,237	5,648	72.1
Jan-86	14,148	16,546	3,509	20,055	5,907	70.5
Jun-86	12,749	16,134	3,267	19,401	6,652	65.7
Dec-86	13,007	15,517	3,146	18,663	5,656	69.7
Jan-87	13,217	15,117	3,140	18,257	5,040	72.4
Jun-87	11,918	14,672	3,033	17,705	5,787	67.3
Dec-87	13,196	14,474	3,025	17,499	4,303	75.4
Jan-88	13,542	14,126	3,150	17,276	3,734	78.4
Jun-88	12,233	13,792	3,074	16,866	4,633	72.5
Dec-88	13,001	13,561	2,993	16,554	3,553	78.5
Jan-89	12,969	13,333	3,080	16,413	3,444	79.0
Jun-89	12,247	13,017	2,954	15,971	3,724	76.7
Dec-89	12,564	13,397	2,833	16,230	3,666	77.4
Jan-90	13,095	13,340	2,963	16,303	3,208	80.3
Jun-90	12,292	13,206	2,888	16,094	3,802	76.4
Dec-90	12,836	13,171	2,982	16,153	3,317	79.5
Jan-91	13,040	13,080	2,951	16,031	2,991	81.3
Jun-91	12,105	12,919	2,839	15,758	3,653	76.8
Dec-91	12,778	12,702	2,809	15,511	2,733	82.4
Jan-92	12,668	12,399	2,926	15,325	2,657	82.7
Jun-92	11,913	12,153	2,826	14,979	3,066	79.5
Dec-92	12,476	12,340	2,811	15,151	2,675	82.3
Jan-93	12,676	12,112	3,038	15,150	2,474	83.7
Jun-93	12,562	12,370	2,945	15,315	2,753	82.0
Dec-93	12,658	12,281	2,900	15,181	2,523	83.4
Jan-94	12,630	12,195	2,851	15,046	2,416	83.9
Jun-94	12,797	12,508	2,751	15,259	2,462	83.9
Dec-94	13,069	12,693	2,712	15,405	2,336	84.8
Jan-95[a]	12,208	12,392	2,684	15,076	2,868	81.0
Jun-95[a]	12,698	12,371	2,588	14,959	2,261	84.9
Dec-95[a]	12,587	12,812	2,537	15,349	2,762	82.0

[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.

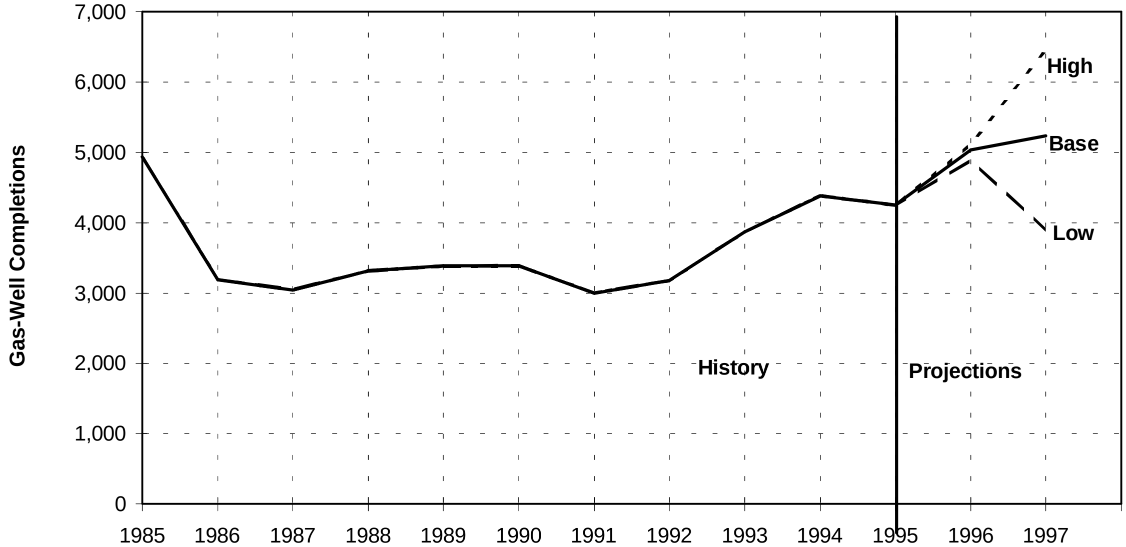
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C11016. Productive Capacity: Model GASCAP94 C110196.

Table 6. Texas (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
		Low Case Projection				
Jan-96	12,611	12,794	2,563	15,357	2,746	82.1
Jun-96	13,254	12,954	2,568	15,522	2,268	85.4
Dec-96	12,847	13,494	2,472	15,966	3,119	80.5
Jan-97	13,216	13,471	2,442	15,913	2,697	83.1
Jun-97	13,504	13,060	2,372	15,432	1,928	87.5
Dec-97	13,777	12,895	2,288	15,183	1,406	90.7
		Base Case Projection				
Jan-96	12,611	12,794	2,563	15,357	2,746	82.1
Jun-96	13,254	12,954	2,568	15,522	2,268	85.4
Dec-96	12,838	13,603	2,521	16,124	3,286	79.6
Jan-97	13,203	13,637	2,510	16,147	2,944	81.8
Jun-97	13,504	13,645	2,468	16,113	2,609	83.8
Dec-97	13,565	14,220	2,429	16,649	3,084	81.5
		High Case Projection				
Jan-96	12,611	12,794	2,563	15,357	2,746	82.1
Jun-96	13,254	12,954	2,568	15,522	2,268	85.4
Dec-96	12,831	13,659	2,563	16,222	3,391	79.1
Jan-97	13,203	13,714	2,575	16,289	3,086	81.1
Jun-97	13,504	14,046	2,548	16,594	3,090	81.4
Dec-97	13,397	15,402	2,535	17,937	4,540	74.7

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, I and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

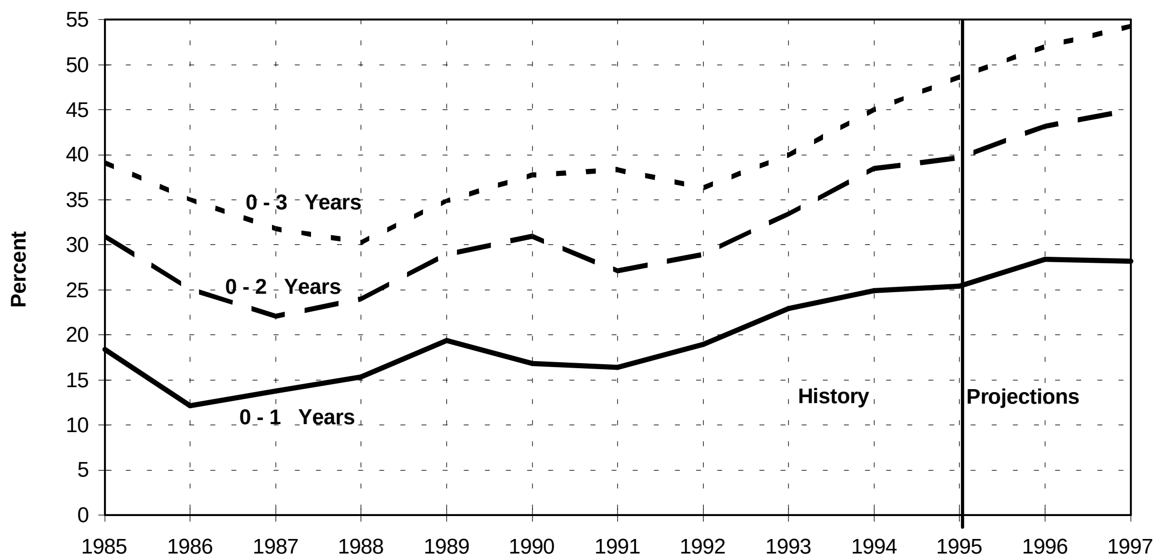
Figure 15. Texas (Excluding Gulf of Mexico OCS) Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

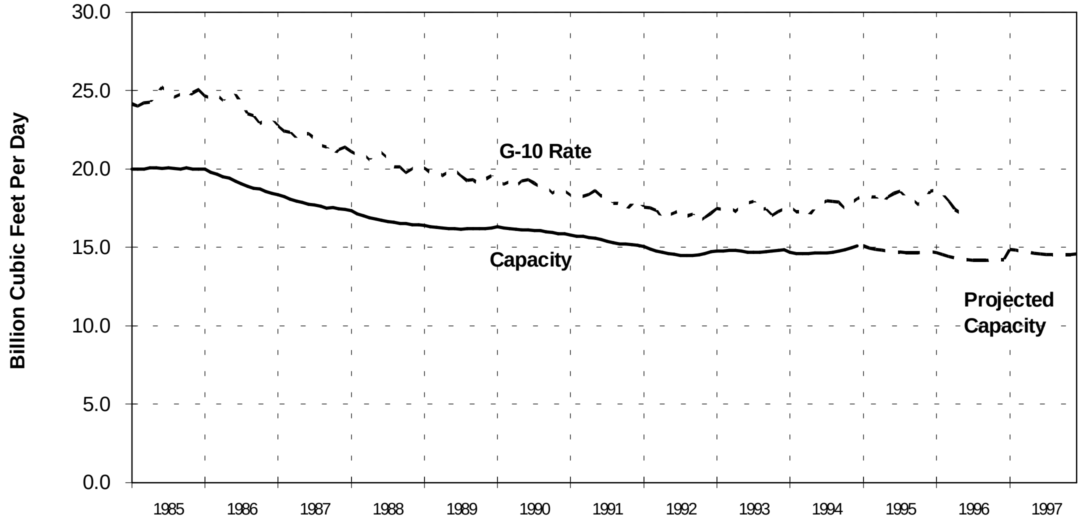
Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 16. Percent of Total Wellhead Productive Capacity of Texas (Excluding Gulf of Mexico OCS) Gas Wells by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 17. Texas (Excluding Gulf of Mexico OCS) Monthly Gross Gas-Well Gas Productive Capacity and G-10 Rate, 1985-1997



Note: Capacity projection plotted for base case only.
Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Railroad Commission of Texas. Projections: Model GASCAP94 C110196.

Operators of Texas gas wells are required to make a production test of each gas well semi-annually and report the test on Form G-10 unless the well is exempt from testing. All gas wells producing less than 100 thousand cubic feet per day are automatically exempt. Each month, the TRC determines statewide gas well deliverability by summing the latest available G-10 test rates. However, the TRC does not necessarily expect that this deliverability (sum of G-10 test rates) can be achieved. This is true for the following reasons:

- The daily rate reported on a Form G-10 is of 72 hours duration, and that rate cannot be sustained for a month by most gas-well completions.
- If all gas-well completions were produced at the daily rate shown on a G-10, increased back-pressures would result, prohibiting gas from many wells from getting into the pipeline system.
- The daily rates reported on the form G-10 reflects the ability of gas-well completions to produce at the time they are tested. However, each TRC deliverability estimate (sum of latest G-10 tests) contains well test data that may be as much as five or more months old.

Capacity estimated in this report is the daily rate that can be sustained for a month. Rates reported on the G-10 tests are required to be sustainable for only 72 hours.

Both, however, exhibit a similar downward trend. Capacity is projected to increase during 1996 and 1997. Data from the G-10 tests are plotted through June 1996.

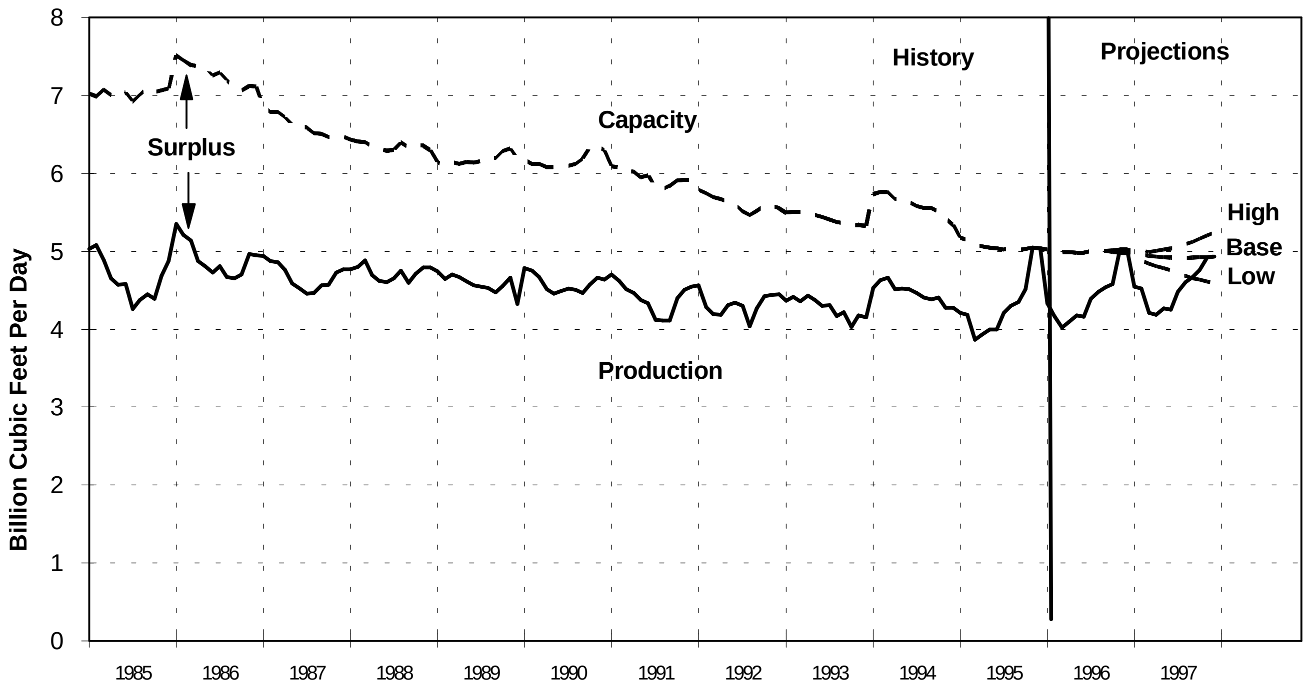
Louisiana (Excluding Gulf of Mexico OCS)

Louisiana has been a large producer of natural gas for many years. Gas produced comes from high permeability, water-drive, deep and sometimes over-pressured formations on the Gulf Coast as well as from low permeability and relatively shallow reservoirs in North Louisiana. In 1994, the two fields producing the largest volume of natural gas in the State were the Chalkey (63 Bcf) and Lake Arthur South (63 Bcf) fields, according to Dwight's data. In 1994, almost 9 percent of the total dry gas produced in the lower 48 States came from Louisiana.{13}

The following pages include Tables 7 and 8 and Figures 18 through 20, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age. These data exclude the OCS.

Production and productive capacity are equal with no surplus in November and December of 1995, 1996, and 1997 for all three cases. For the low case, there is no surplus for the two additional months of September and October of 1997. The production is plotted for the base case only in Figure 18.

Figure 18. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 7. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity, 1985-1995 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	5,030	6,497	525	7,022	1,992	71.6
Jun-85	4,581	6,499	539	7,038	2,457	65.1
Dec-85	4,876	6,574	516	7,090	2,214	68.8
Jan-86	5,353	6,930	585	7,515	2,162	71.2
Jun-86	4,724	6,715	538	7,253	2,529	65.1
Dec-86	4,950	6,534	579	7,113	2,163	69.6
Jan-87	4,940	6,288	583	6,871	1,931	71.9
Jun-87	4,523	6,040	570	6,610	2,087	68.4
Dec-87	4,764	5,899	573	6,472	1,708	73.6
Jan-88	4,772	5,863	569	6,432	1,660	74.2
Jun-88	4,599	5,745	546	6,291	1,692	73.1
Dec-88	4,796	5,759	540	6,299	1,503	76.1
Jan-89	4,740	5,640	502	6,142	1,402	77.2
Jun-89	4,567	5,654	483	6,137	1,570	74.4
Dec-89	4,320	5,772	420	6,192	1,872	69.8
Jan-90	4,785	5,734	440	6,174	1,389	77.5
Jun-90	4,486	5,644	432	6,076	1,590	73.8
Dec-90	4,635	5,855	443	6,298	1,663	73.6
Jan-91	4,703	5,673	419	6,092	1,389	77.2
Jun-91	4,332	5,557	415	5,972	1,640	72.5
Dec-91	4,544	5,494	422	5,916	1,372	76.8
Jan-92	4,560	5,278	512	5,790	1,230	78.8
Jun-92	4,342	5,102	504	5,606	1,264	77.5
Dec-92	4,447	5,054	497	5,551	1,104	80.1
Jan-93	4,360	5,100	398	5,498	1,138	79.3
Jun-93	4,303	5,041	402	5,443	1,140	79.1
Dec-93	4,155	4,952	376	5,328	1,173	78.0
Jan-94	4,528	5,253	479	5,732	1,204	79.0
Jun-94	4,518	5,163	470	5,633	1,115	80.2
Dec-94	4,276	4,870	473	5,343	1,067	80.0
Jan-95[a]	4,206	4,712	463	5,175	969	81.3
Jun-95[a]	3,998	4,585	453	5,038	1,040	79.4
Dec-95[a]	5,042	4,568	474	5,042	0	100.0

[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.

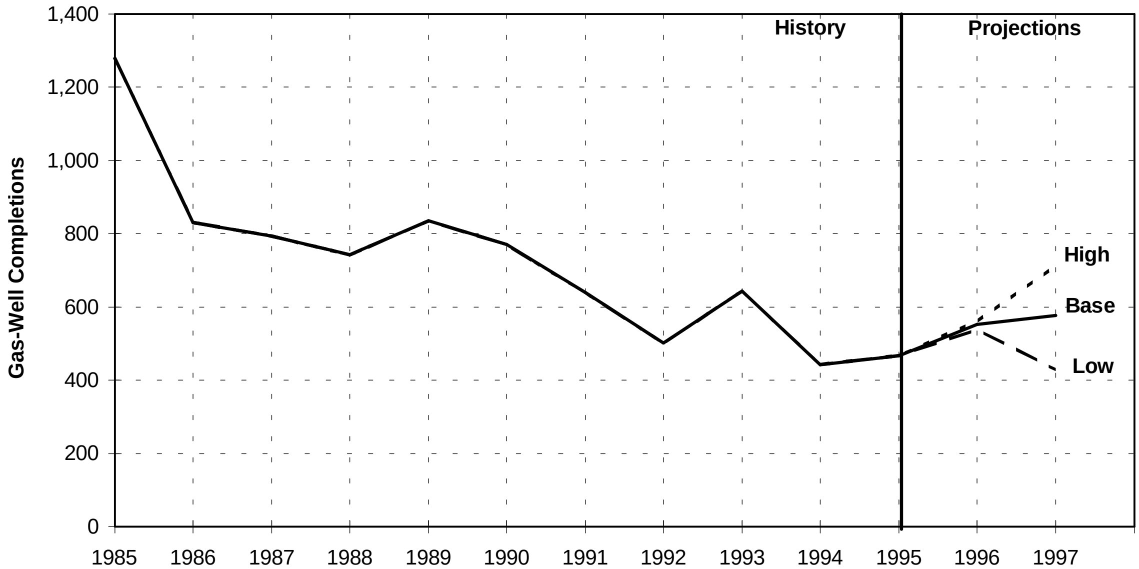
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C11016. Productive Capacity: Model GASCAP94 C110196.

Table 8. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
			Low Case Projection			
Jan-96	4,329	4,541	479	5,020	691	86.2
Jun-96	4,156	4,503	483	4,986	830	83.4
Dec-96	4,968	4,500	468	4,968	0	100.0
Jan-97	4,549	4,459	462	4,921	372	92.4
Jun-97	4,251	4,303	451	4,754	503	89.4
Dec-97	4,588	4,150	438	4,588	0	100.0
			Base Case Projection			
Jan-96	4,329	4,541	479	5,020	691	86.2
Jun-96	4,156	4,503	483	4,986	830	83.4
Dec-96	5,002	4,525	477	5,002	0	100.0
Jan-97	4,544	4,498	475	4,973	429	91.4
Jun-97	4,251	4,449	470	4,919	668	86.4
Dec-97	4,929	4,464	465	4,929	0	100.0
			High Case Projection			
Jan-96	4,329	4,541	479	5,020	691	86.2
Jun-96	4,156	4,503	483	4,986	830	83.4
Dec-96	5,025	4,540	485	5,025	0	100.0
Jan-97	4,544	4,518	487	5,005	461	90.8
Jun-97	4,251	4,551	485	5,036	785	84.4
Dec-97	5,232	4,746	486	5,232	0	100.0

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

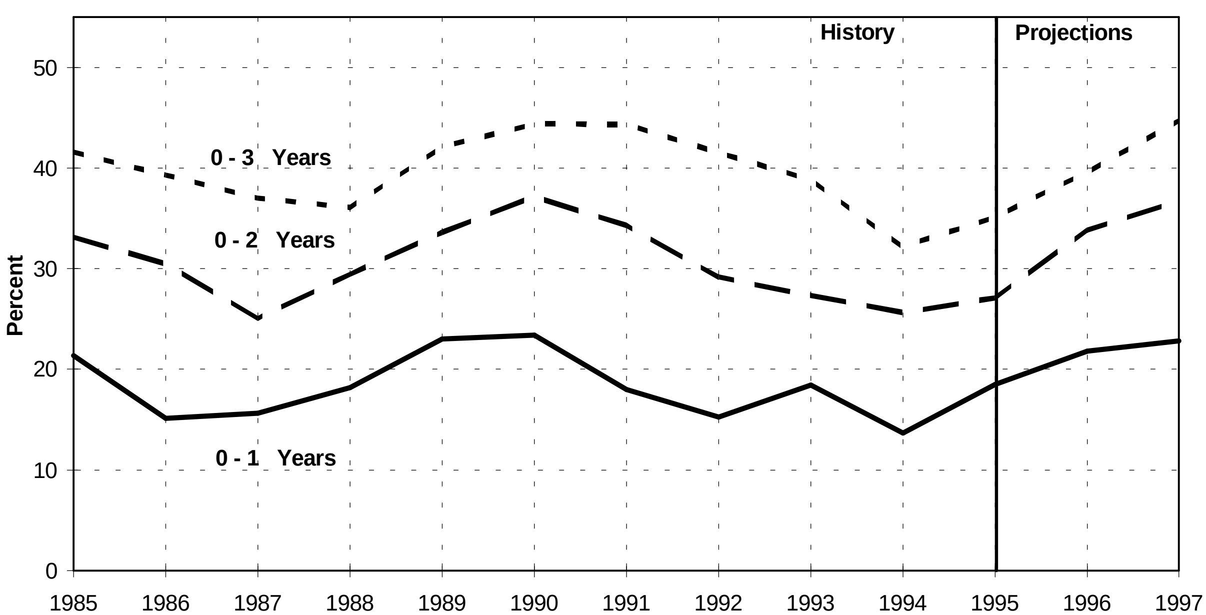
Figure 19. Louisiana (Excluding Gulf of Mexico OCS) Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 20. Percent of Total Wellhead Productive Capacity of Louisiana (Excluding Gulf Mexico OCS) Gas Wells by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

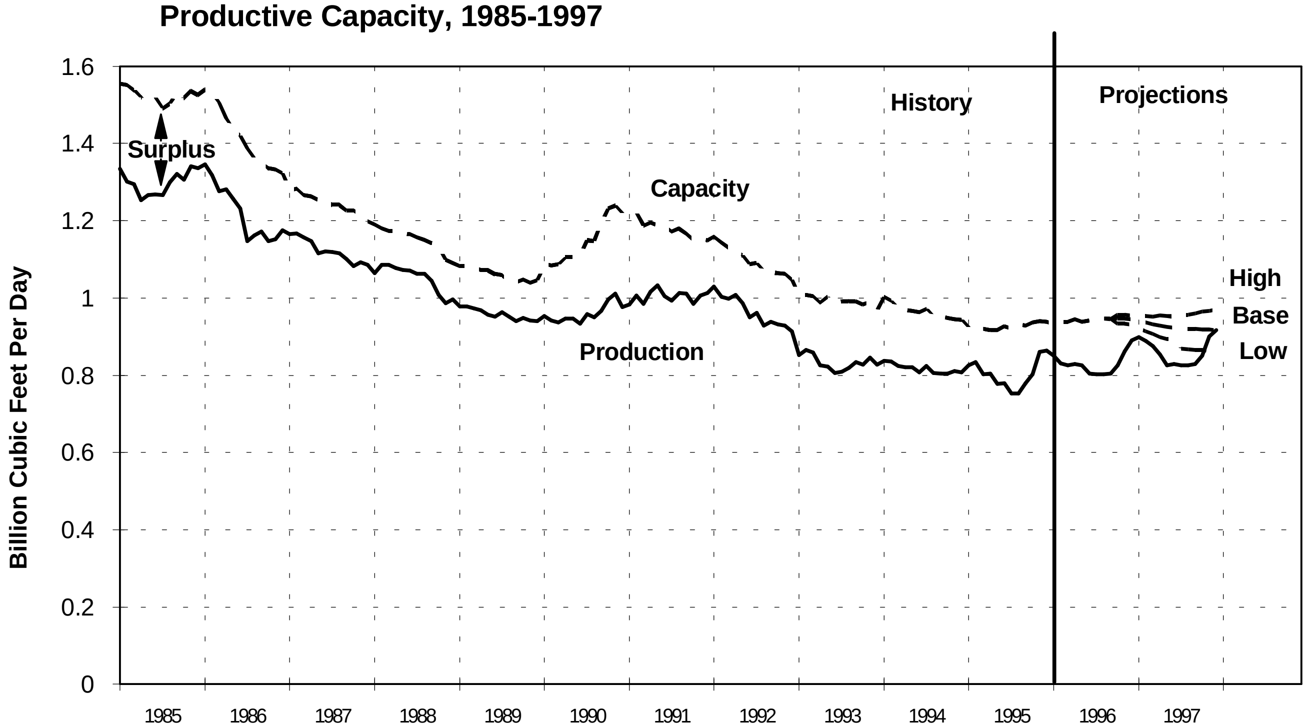
California (Including Pacific OCS)

California is a net importer of natural gas. All California gas produced is used within the State. In 1994, more than half the total gas produced in California and Pacific OCS was oil-well gas.{13}

In 1994, Elk Hills and Coalingas East Extension oil fields were the two largest producers of natural gas. The two largest gas fields were Rio Vista and Pitas Point; the latter is in the Pacific OCS. This information was obtained from the California Department of Conservation.

The following pages include Tables 9 and 10 and Figures 21 through 23, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age. These data include the OCS. Production and productive capacity are equal, with no surplus for November and December 1997 in the *low* case and for December 1997 in the *base* case.

Figure 21. California (Including Pacific OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 9. California (Including Pacific OCS) Dry Gas Production and Wellhead Productive Capacity, 1985-1995 (Million Cubic Feet Per Day)

		Dry Gas Productive Capacity				
Month-Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	1,335	803	751	1,554	219	85.9
Jun-85	1,269	750	770	1,520	251	83.5
Dec-85	1,337	740	786	1,526	189	87.6
Jan-86	1,347	765	775	1,540	193	87.5
Jun-86	1,231	687	734	1,421	190	86.6
Dec-86	1,175	620	703	1,323	148	88.8
Jan-87	1,165	583	696	1,279	114	91.1
Jun-87	1,120	541	714	1,255	135	89.2
Dec-87	1,086	491	707	1,198	112	90.7
Jan-88	1,065	495	695	1,190	125	89.5
Jun-88	1,071	473	692	1,165	94	91.9
Dec-88	996	435	655	1,090	94	91.4
Jan-89	979	424	659	1,083	104	90.4
Jun-89	951	404	658	1,062	111	89.5
Dec-89	940	398	648	1,046	106	89.9
Jan-90	954	436	652	1,088	134	87.7
Jun-90	933	471	638	1,109	176	84.1
Dec-90	976	583	637	1,220	244	80.0
Jan-91	984	594	625	1,219	235	80.7
Jun-91	1,005	558	628	1,186	181	84.7
Dec-91	1,013	514	635	1,149	136	88.2
Jan-92	1,030	527	632	1,159	129	88.9
Jun-92	950	457	630	1,087	137	87.4
Dec-92	913	419	628	1,047	134	87.2
Jan-93	852	433	575	1,008	156	84.5
Jun-93	806	408	579	987	181	81.7
Dec-93	828	380	588	968	140	85.5
Jan-94	838	429	574	1,003	165	83.5
Jun-94	807	387	576	963	156	83.8
Dec-94	807	343	601	944	137	85.5
Jan-95[a]	826	336	588	924	98	89.4
Jun-95[a]	779	330	597	927	148	84.0
Dec-95[a]	864	339	600	939	75	92.0

[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.

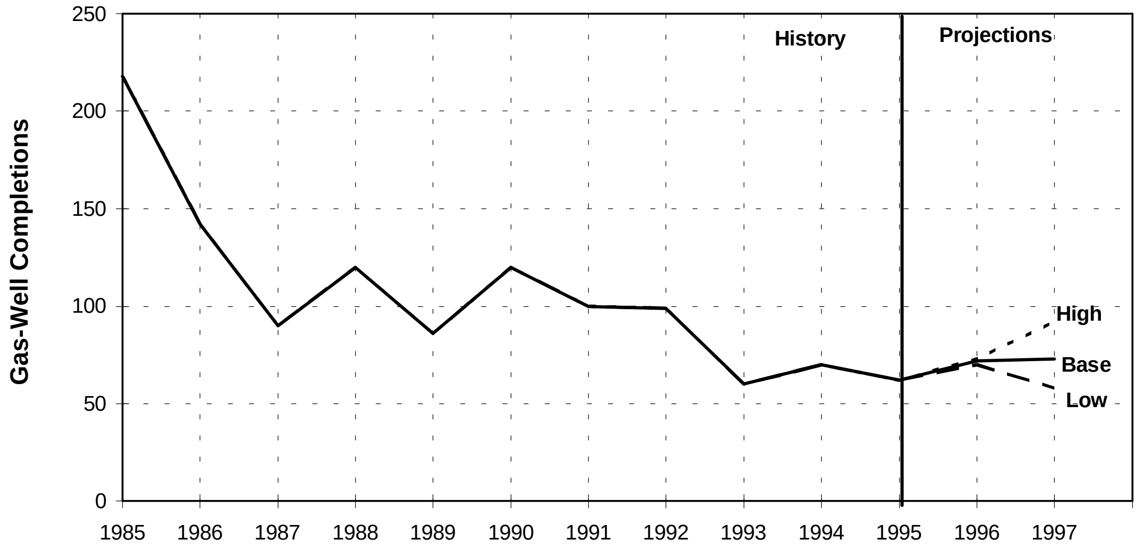
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C11016. Productive Capacity: Model GASCAP94 C110196.

Table 10. California (Including Pacific OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
				Low Case Projection		
Jan-96	851	334	598	932	81	91.3
Jun-96	804	333	609	942	138	85.4
Dec-96	891	341	591	932	41	95.6
Jan-97	900	335	585	920	20	97.8
Jun-97	829	318	571	889	60	93.3
Dec-97	859	303	556	859	0	100.0
				Base Case Projection		
Jan-96	851	334	598	932	81	91.3
Jun-96	804	333	609	942	138	85.4
Dec-96	891	344	601	945	54	94.3
Jan-97	899	340	599	939	40	95.7
Jun-97	829	331	592	923	94	89.8
Dec-97	916	330	586	916	0	100.0
				High Case Projection		
Jan-96	851	334	598	932	81	91.3
Jun-96	804	333	609	942	138	85.4
Dec-96	890	345	610	955	65	93.2
Jan-97	899	342	613	955	56	94.1
Jun-97	829	343	609	952	123	87.1
Dec-97	918	360	609	969	51	94.7

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

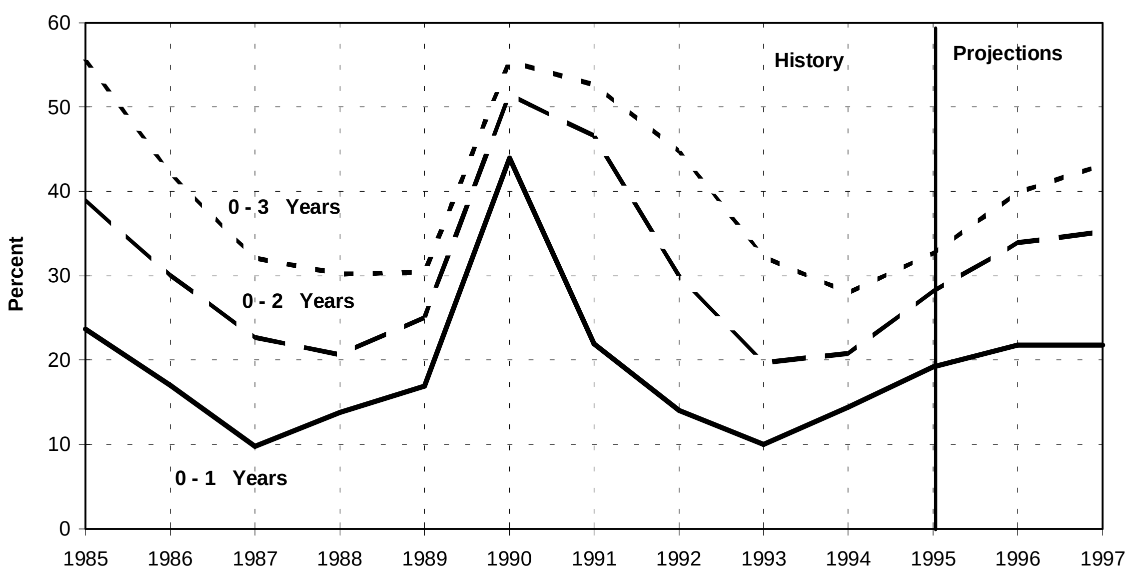
Figure 22. California (Including Pacific OCS) Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 23. Percent of Total Wellhead Productive Capacity of California (Including Pacific OCS) Gas Wells by Well Age, 1985-1997 (Base Case)



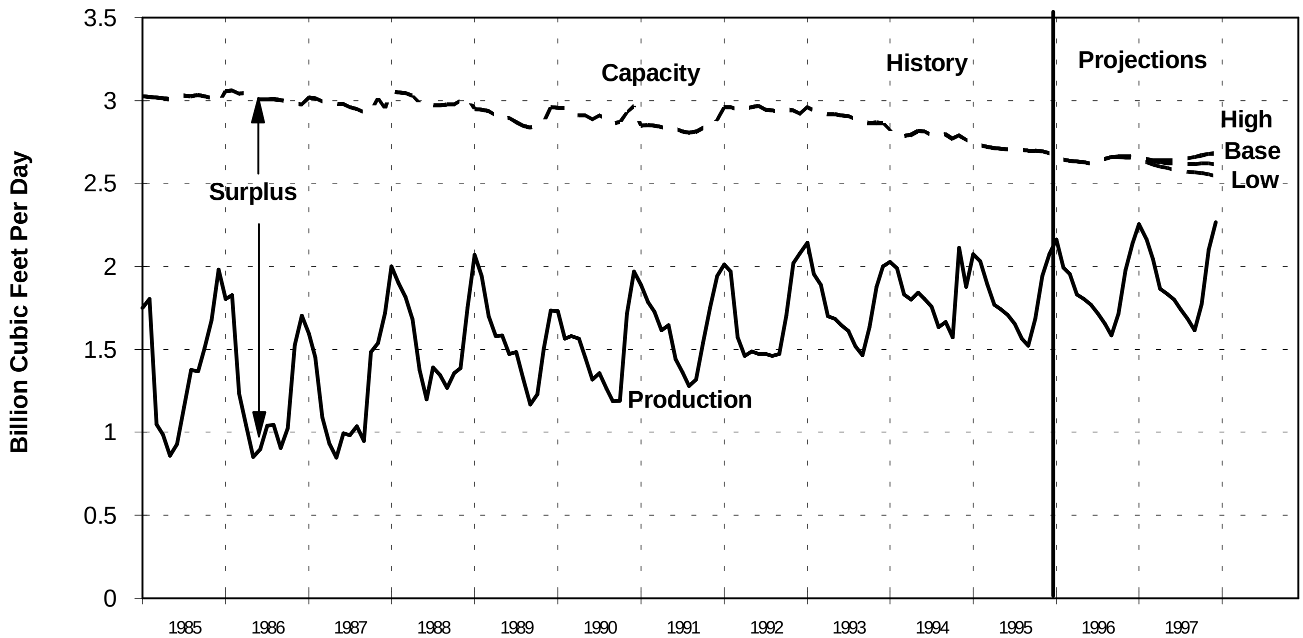
Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Kansas

In 1994 over half the gas produced in the State of Kansas came from the giant Hugoton field. Hugoton field 1994 production of 419 billion cubic feet of gas was almost 3 percent more than in 1993 and over 29 percent more than five years earlier in 1990. This information was obtained from Dwight's. Hugoton field occupies almost all of the western half of Kansas and extends south into Oklahoma and the northern part of the Texas Panhandle. Production from this field generally comes from low permeability sandy carbonate reservoir rocks.

The following pages include Tables 11, 12, and Figures 24 through 26. These data provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 24. Kansas Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 11. Kansas Dry Gas Production and Wellhead Productive Capacity, 1985-1995
(Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	1,749	2,798	227	3,025	1,276	57.8
Jun-85	928	2,792	233	3,025	2,097	30.7
Dec-85	1,981	2,749	241	2,990	1,009	66.3
Jan-86	1,806	2,772	287	3,059	1,253	59.0
Jun-86	897	2,762	245	3,007	2,110	29.8
Dec-86	1,702	2,751	226	2,977	1,275	57.2
Jan-87	1,597	2,766	251	3,017	1,420	52.9
Jun-87	994	2,727	252	2,979	1,985	33.4
Dec-87	1,719	2,704	248	2,952	1,233	58.2
Jan-88	2,002	2,775	281	3,056	1,054	65.5
Jun-88	1,198	2,676	302	2,978	1,780	40.2
Dec-88	1,753	2,735	279	3,014	1,261	58.2
Jan-89	2,071	2,700	248	2,948	877	70.3
Jun-89	1,472	2,652	244	2,896	1,424	50.8
Dec-89	1,736	2,741	218	2,959	1,223	58.7
Jan-90	1,729	2,678	279	2,957	1,228	58.5
Jun-90	1,316	2,613	275	2,888	1,572	45.6
Dec-90	1,970	2,699	268	2,967	997	66.4
Jan-91	1,888	2,649	200	2,849	961	66.3
Jun-91	1,442	2,628	202	2,830	1,388	51.0
Dec-91	1,941	2,690	193	2,883	942	67.3
Jan-92	2,014	2,745	215	2,960	946	68.0
Jun-92	1,472	2,762	205	2,967	1,495	49.6
Dec-92	2,079	2,722	200	2,922	843	71.1
Jan-93	2,143	2,756	207	2,963	820	72.3
Jun-93	1,647	2,691	220	2,911	1,264	56.6
Dec-93	1,999	2,659	204	2,863	864	69.8
Jan-94	2,027	2,603	216	2,819	792	71.9
Jun-94	1,806	2,593	222	2,815	1,009	64.2
Dec-94	1,877	2,550	216	2,766	889	67.9
Jan-95[a]	2,074	2,524	211	2,735	661	75.8
Jun-95[a]	1,708	2,501	207	2,708	1,000	63.1
Dec-95[a]	2,075	2,495	189	2,684	609	77.3

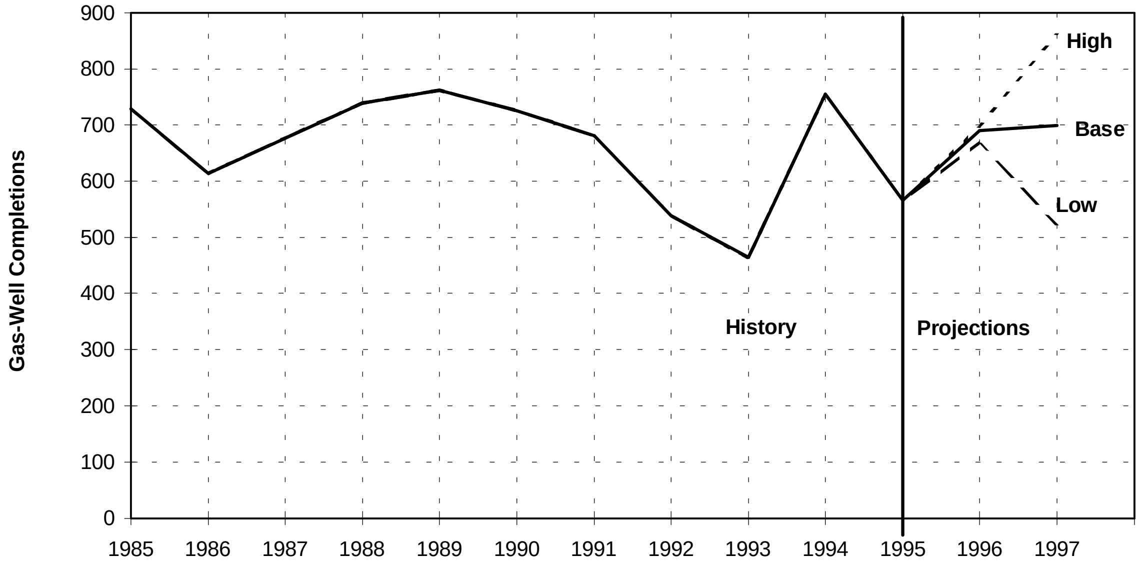
[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C11016. Productive Capacity: Model GASCAP94 C110196.

Table 12. Kansas Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
	Low Case Projection					
Jan-96	2,164	2,475	191	2,666	502	81.2
Jun-96	1,770	2,430	192	2,622	852	67.5
Dec-96	2,143	2,468	185	2,653	510	80.8
Jan-97	2,256	2,457	183	2,640	384	85.5
Jun-97	1,801	2,407	178	2,585	784	69.7
Dec-97	2,303	2,372	172	2,544	241	90.5
	Base Case Projection					
Jan-96	2,164	2,475	191	2,666	502	81.2
Jun-96	1,770	2,431	192	2,623	853	67.5
Dec-96	2,141	2,471	189	2,660	519	80.5
Jan-97	2,254	2,462	188	2,650	396	85.1
Jun-97	1,801	2,434	185	2,619	818	68.8
Dec-97	2,268	2,435	183	2,618	350	86.6
	High Case Projection					
Jan-96	2,164	2,475	191	2,666	502	81.2
Jun-96	1,770	2,431	192	2,623	853	67.5
Dec-96	2,140	2,471	192	2,663	523	80.4
Jan-97	2,254	2,461	193	2,654	400	84.9
Jun-97	1,801	2,450	191	2,641	840	68.2
Dec-97	2,240	2,492	191	2,683	443	83.5

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

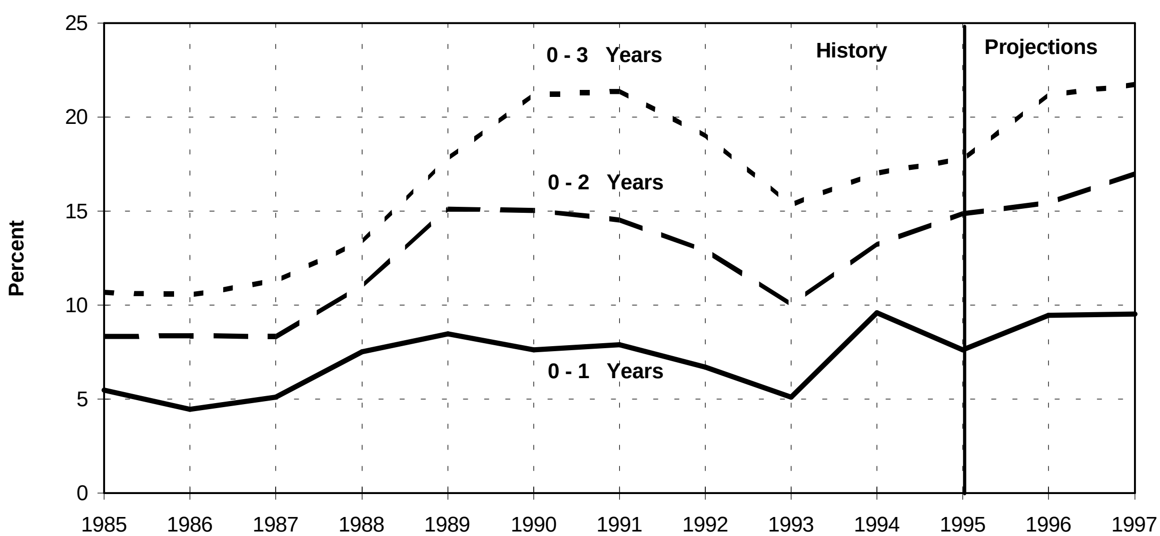
Figure 25. Kansas Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 26. Percent of Total Wellhead Productive Capacity of Kansas Gas Wells by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

New Mexico

Most of this State's natural gas is produced from fields in northwestern New Mexico from the San Juan Basin. San Juan Basin gas production increased from 536 billion cubic feet in 1990 to 1,138 billion in 1994. Practically all of the oil-well gas produced comes from the Permian Basin of southeast New Mexico.

Basin field, the largest gas field in the State, produced 680 billion cubic feet of mixed gas-well conventional and coalbed gas during 1994. This was an increase of 44 billion cubic feet over the amount produced in 1993. New Mexico has been an area of intense drilling for coalbed gas since 1989. Coalbed gas production from this field increased 217 percent from 1990 through 1994.

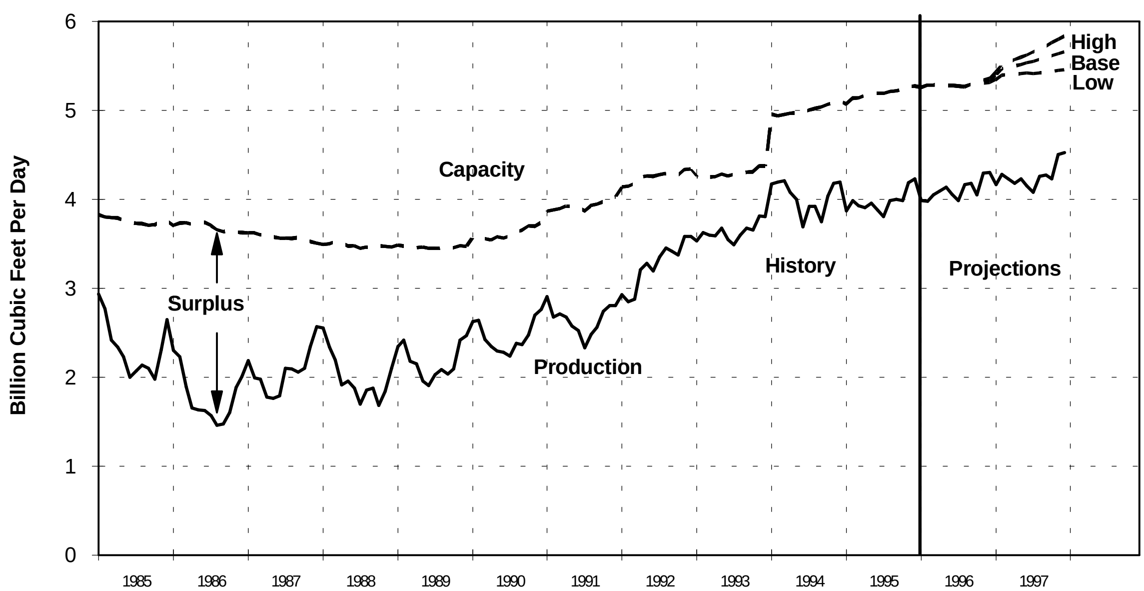
It is expected that, with the current reduction in new well completions, gas production from this area is near its peak. Drilling dramatically decreased in 1993 after the Section 29 gas tax credit expired.

Coalbed gas producted in New Mexico was about 15 percent of the State's total dry gas producted in 1990, 23 percent in 1991, 31 percent in 1992, 36 percent in 1993, and 39 percent in 1994.{12} Coalbed gas-well completions were treated separately from the conventional gas-well completions in this report. Coalbed gas wells have an increasing rate of production the first few years of their lives. After reaching their peak production rates, coalbed gas wells are predicted to have very low decline rates and therefore very long lives. Coalbed gas capacity has shown an increase in the last few years. (Figure 28).

There is a decrease in the New Mexico total gas-well completions for 1996 and an increase in 1977. In 1996, the number of drilling rigs in New Mexico decreased. A decrease in the number of gas-well completions resulted, because the number of completions is a function of the number of rigs. Rigs are forecast to increase in 1997 for the *base* and *high* cases and decrease for the *low* case for the lower 48 States.After taking into account the completion per rig and State distribution factors, the New Mexico total gas-well completions are expected to increase in 1997.

The following pages include Tables 13, 14, and Figures 27 through 30, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 27. New Mexico Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 13. New Mexico Dry Gas Production and Wellhead Productive Capacity, 1985-1995
(Million Cubic Feet Per Day)

		Dry Gas Productive Capacity				
Month-Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	2,939	3,267	561	3,828	889	76.8
Jun-85	2,003	3,203	548	3,751	1,748	53.4
Dec-85	2,647	3,206	554	3,760	1,113	70.4
Jan-86	2,305	3,136	574	3,710	1,405	62.1
Jun-86	1,629	3,191	551	3,742	2,113	43.5
Dec-86	2,007	3,105	521	3,626	1,619	55.4
Jan-87	2,188	3,089	536	3,625	1,437	60.4
Jun-87	1,795	3,039	525	3,564	1,769	50.4
Dec-87	2,569	2,972	539	3,511	942	73.2
Jan-88	2,554	2,973	524	3,497	943	73.0
Jun-88	1,879	2,967	512	3,479	1,600	54.0
Dec-88	2,101	2,962	503	3,465	1,364	60.6
Jan-89	2,347	2,988	501	3,489	1,142	67.3
Jun-89	1,907	2,981	472	3,453	1,546	55.2
Dec-89	2,468	3,014	458	3,472	1,004	71.1
Jan-90	2,626	3,062	508	3,570	944	73.6
Jun-90	2,282	3,076	491	3,567	1,285	64.0
Dec-90	2,762	3,233	504	3,737	975	73.9
Jan-91	2,910	3,317	551	3,868	958	75.2
Jun-91	2,526	3,373	539	3,912	1,386	64.6
Dec-91	2,810	3,486	547	4,033	1,223	69.7
Jan-92	2,931	3,579	563	4,142	1,211	70.8
Jun-92	3,192	3,696	564	4,260	1,068	74.9
Dec-92	3,585	3,790	553	4,343	758	82.5
Jan-93	3,531	3,693	565	4,258	727	82.9
Jun-93	3,545	3,707	556	4,263	718	83.2
Dec-93	3,808	3,805	571	4,376	568	87.0
Jan-94	4,173	4,419	539	4,958	785	84.2
Jun-94	3,696	4,492	487	4,979	1,283	74.2
Dec-94	4,195	4,591	515	5,106	911	82.2
Jan-95[a]	3,870	4,569	505	5,074	1,204	76.3
Jun-95[a]	3,875	4,668	522	5,190	1,315	74.7
Dec-95[a]	4,234	4,758	519	5,277	1,043	80.2

[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.

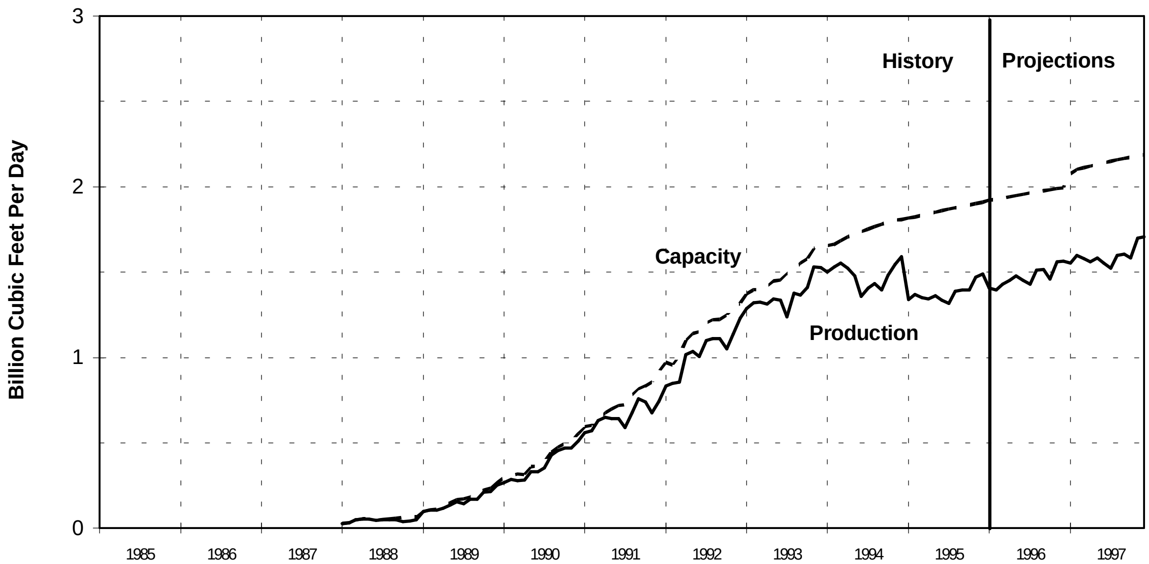
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C11016. Productive Capacity: Model GASCAP94 C110196.

Table 14. New Mexico Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
	Low Case Projection					
Jan-96	3,990	4,739	524	5,263	1,273	75.8
Jun-96	4,061	4,755	527	5,282	1,221	76.9
Dec-96	4,309	4,808	510	5,318	1,009	81.0
Jan-97	4,175	4,843	504	5,347	1,172	78.1
Jun-97	4,154	4,927	491	5,418	1,264	76.7
Dec-97	4,599	4,978	476	5,454	855	84.3
	Base Case Projection					
Jan-96	3,990	4,739	524	5,263	1,273	75.8
Jun-96	4,061	4,756	527	5,283	1,222	76.9
Dec-96	4,306	4,826	520	5,346	1,040	80.5
Jan-97	4,170	4,881	518	5,399	1,229	77.2
Jun-97	4,154	5,025	511	5,536	1,382	75.0
Dec-97	4,528	5,154	505	5,659	1,131	80.0
	High Case Projection					
Jan-96	3,990	4,739	524	5,263	1,273	75.8
Jun-96	4,061	4,757	527	5,284	1,223	76.9
Dec-96	4,304	4,835	528	5,363	1,059	80.3
Jan-97	4,170	4,908	531	5,439	1,269	76.7
Jun-97	4,154	5,099	528	5,627	1,473	73.8
Dec-97	4,472	5,311	527	5,838	1,366	76.6

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

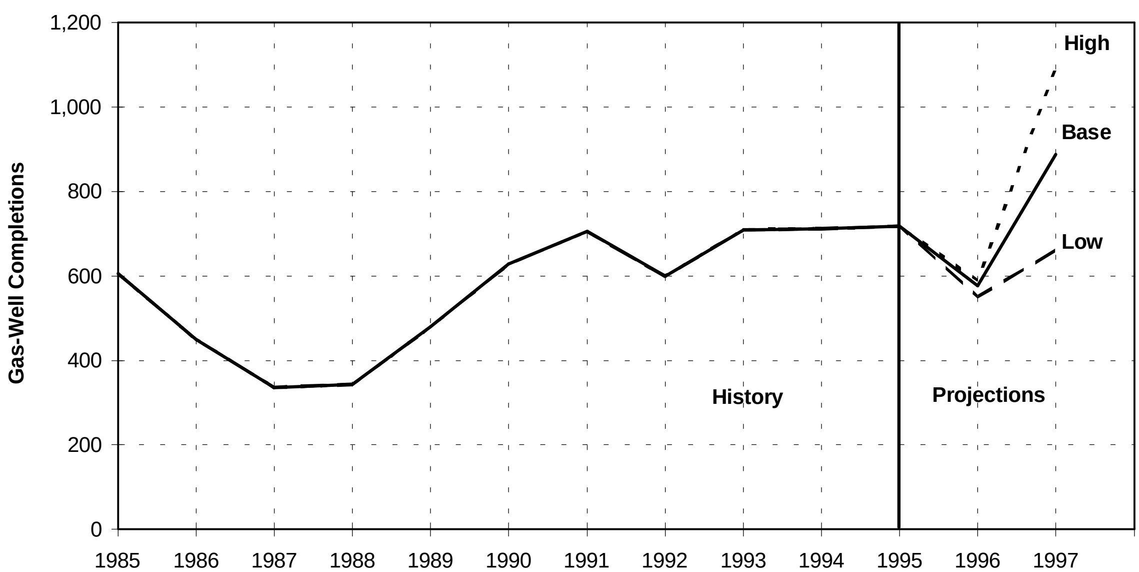
Figure 28. New Mexico Dry Coalbed Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C11016. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

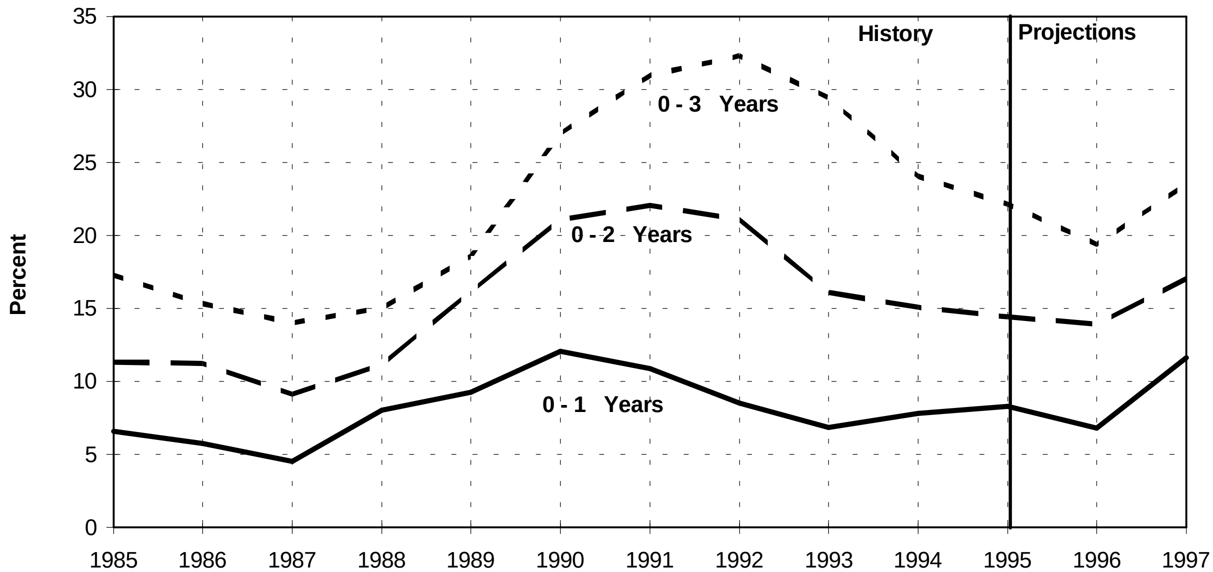
Figure 29. New Mexico Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 30. Percent of Total Wellhead Productive Capacity of New Mexico Gas Wells by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

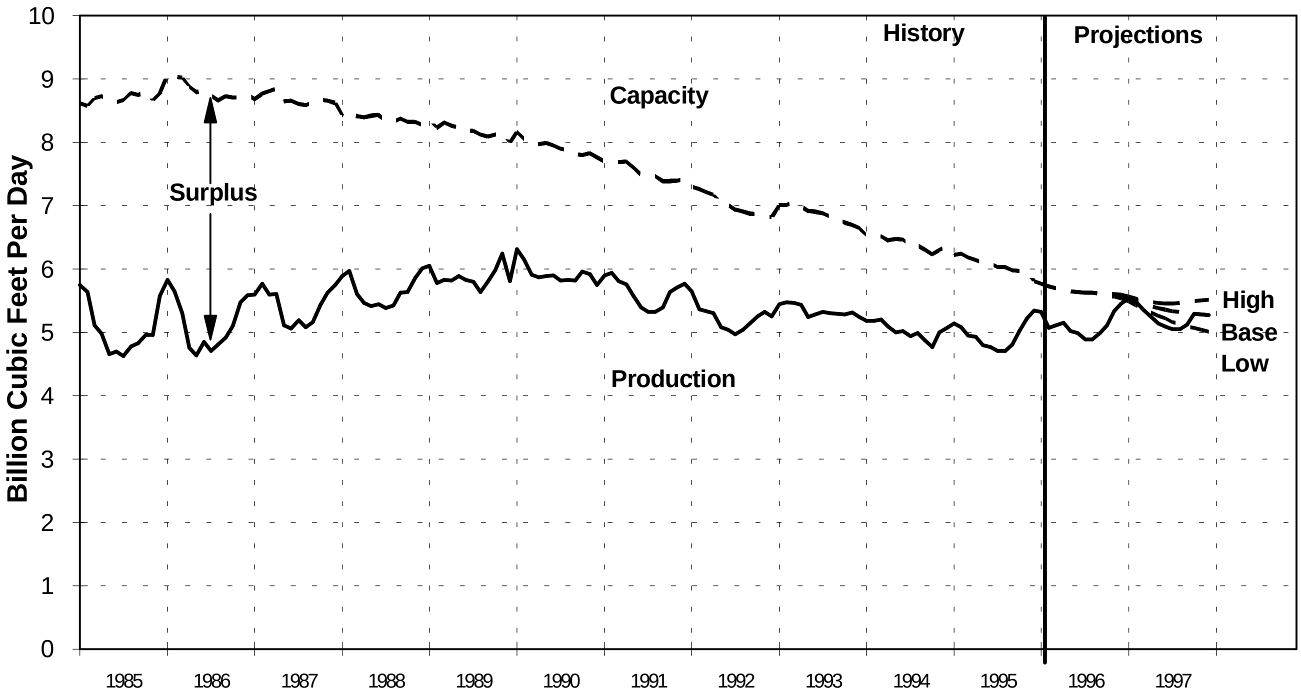
Oklahoma

Oklahoma is among the top three gas-producing States. There are numerous large and small gas fields scattered throughout western Oklahoma. Oil fields with large volumes of associated-dissolved gas are located generally in central Oklahoma. Dwight's EnergyData, Inc., indicates that, in 1994, the top two gas-producing areas were the Mocane-Laverne (99 Bcf) area and the Watonga-Chickasha Trend (92Bcf). The Mocane-Laverne area, located in Northwest Oklahoma, consists of over 50 fields, and the Watonga-Chickasha Trend consists of more than 70 fields.

The following pages include Tables 15 and 16 and Figures 31 through 33, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Production and capacity are equal, indicating no surplus for some months in 1997. In the *low* case, no surplus exists for January, February and September through December. For the *base* case, no surplus exists for January and October through December. For the *high* case, no surplus exists for November and December. The production is plotted for the base case only in Figure 31.

Figure 31. Oklahoma Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 15. Oklahoma Dry Gas Production and Wellhead Productive Capacity, 1985-1995
(Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	5,745	7,429	1,187	8,616	2,871	66.7
Jun-85	4,694	7,491	1,138	8,629	3,935	54.4
Dec-85	5,570	7,569	1,207	8,776	3,206	63.5
Jan-86	5,821	7,552	1,507	9,059	3,238	64.3
Jun-86	4,841	7,516	1,295	8,811	3,970	54.9
Dec-86	5,585	7,480	1,264	8,744	3,159	63.9
Jan-87	5,595	7,451	1,228	8,679	3,084	64.5
Jun-87	5,062	7,353	1,296	8,649	3,587	58.5
Dec-87	5,747	7,408	1,211	8,619	2,872	66.7
Jan-88	5,888	7,221	1,202	8,423	2,535	69.9
Jun-88	5,438	7,204	1,222	8,426	2,988	64.5
Dec-88	6,011	7,088	1,183	8,271	2,260	72.7
Jan-89	6,047	7,129	1,222	8,351	2,304	72.4
Jun-89	5,828	7,026	1,141	8,167	2,339	71.4
Dec-89	5,802	6,955	1,033	7,988	2,186	72.6
Jan-90	6,308	6,937	1,224	8,161	1,853	77.3
Jun-90	5,896	6,858	1,094	7,952	2,056	74.1
Dec-90	5,747	6,751	1,010	7,761	2,014	74.0
Jan-91	5,895	6,758	940	7,698	1,803	76.6
Jun-91	5,395	6,552	941	7,493	2,098	72.0
Dec-91	5,767	6,515	892	7,407	1,640	77.9
Jan-92	5,646	6,396	902	7,298	1,652	77.4
Jun-92	5,036	6,113	893	7,006	1,970	71.9
Dec-92	5,251	5,930	887	6,817	1,566	77.0
Jan-93	5,443	6,182	824	7,006	1,563	77.7
Jun-93	5,275	6,054	846	6,900	1,625	76.4
Dec-93	5,239	5,854	788	6,642	1,403	78.9
Jan-94	5,177	5,711	820	6,531	1,354	79.3
Jun-94	5,015	5,646	817	6,463	1,448	77.6
Dec-94	5,070	5,549	804	6,353	1,283	79.8
Jan-95[a]	5,135	5,456	767	6,223	1,088	82.5
Jun-95[a]	4,769	5,300	775	6,075	1,306	78.5
Dec-95[a]	5,338	5,148	652	5,800	462	92.0

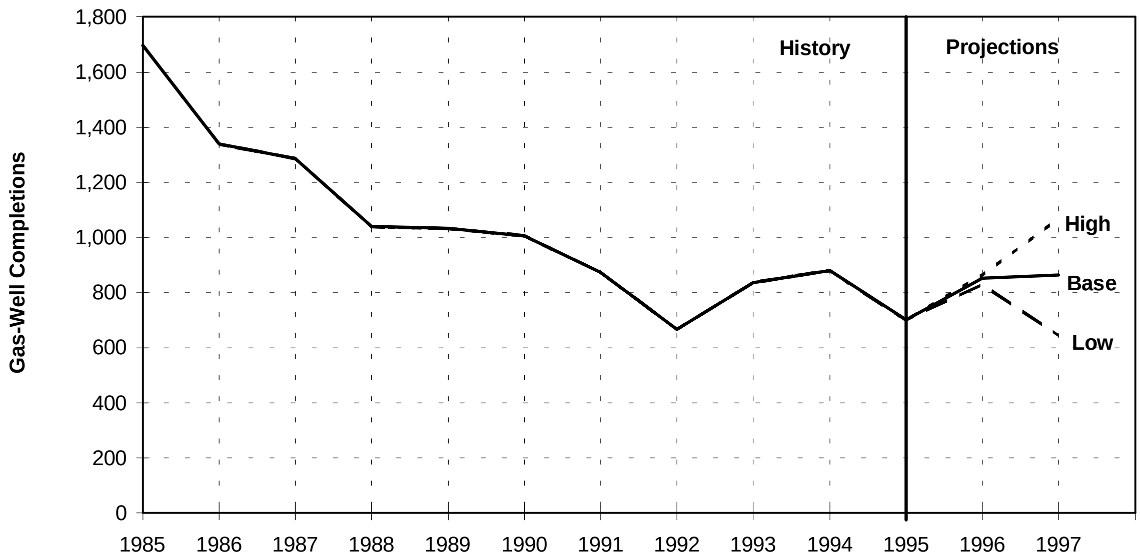
[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C11016. Productive Capacity: Model GASCAP94 C110196.

Table 16. Oklahoma Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
		Low Case Projection				
Jan-96	5,318	5,107	658	5,765	447	92.2
Jun-96	4,990	4,972	659	5,631	641	88.6
Dec-96	5,449	4,896	634	5,530	81	98.5
Jan-97	5,475	4,849	626	5,475	0	100.0
Jun-97	5,085	4,610	608	5,218	133	97.5
Dec-97	5,006	4,420	586	5,006	0	100.0
		Base Case Projection				
Jan-96	5,318	5,107	658	5,765	447	92.2
Jun-96	4,990	4,973	659	5,632	642	88.6
Dec-96	5,445	4,919	647	5,566	121	97.8
Jan-97	5,527	4,883	644	5,527	0	100.0
Jun-97	5,085	4,722	632	5,354	269	95.0
Dec-97	5,271	4,649	622	5,271	0	100.0
		High Case Projection				
Jan-96	5,318	5,107	658	5,765	447	92.2
Jun-96	4,990	4,974	659	5,633	643	88.6
Dec-96	5,442	4,932	657	5,589	147	97.4
Jan-97	5,532	4,900	660	5,560	28	99.5
Jun-97	5,085	4,801	653	5,454	369	93.2
Dec-97	5,514	4,865	649	5,514	0	100.0

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

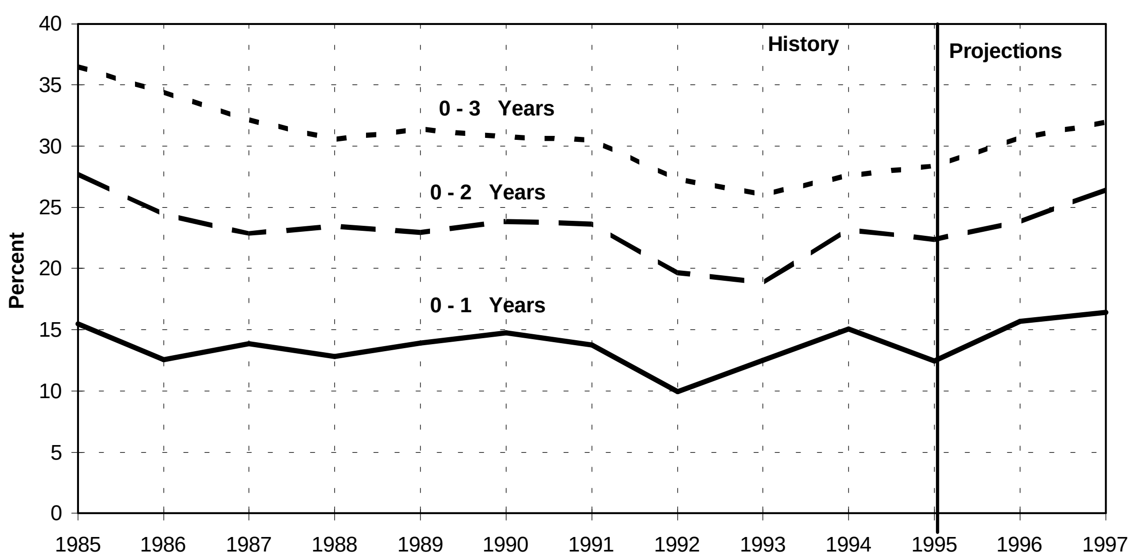
Figure 32. Oklahoma Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 33. Percent of Total Wellhead Productive Capacity of Oklahoma Gas Wells by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

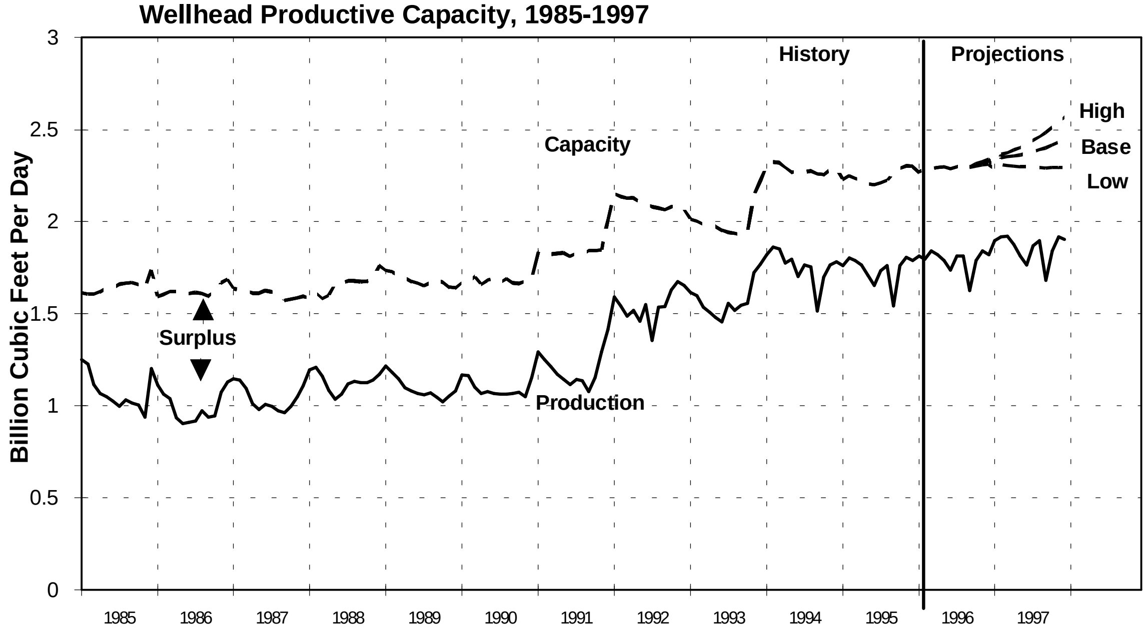
Southeast (Excluding Gulf of Mexico OCS)

The Southeast area includes the States of Arkansas, Mississippi, and Alabama (excluding Gulf of Mexico OCS). Production is from highly permeable deep formations on the Gulf Coast, as well as from low permeability and relatively shallow formations in Arkansas, northern Mississippi, and northern Alabama.

Coalbed gas production in Alabama was 35 percent of the State's total dry gas production in 1990, 47 percent in 1991, 35 percent in 1992, 37 percent in 1993, and 28 percent in 1994. {12} Coalbed gas-well completions in Alabama were treated separately from conventional gas-well completions in this report. Coalbed gas capacity increased through 1995, then began a decline (Figure 35).

The following pages include Tables 17 and 18 and Figures 34 through 37, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 34. Southeast (Excluding Gulf of Mexico OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 17. Southeast (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity, 1985-1995 (Million Cubic Feet Per Day)

		Dry Gas Productive Capacity				
Month-Year	**Dry Production**	**Gas-Well Gas**	**Oil-Well Gas**	**Total Gas**	**Total Surplus**	**Utilization (percent)**
Jan-85	1,251	1,472	141	1,613	362	77.6
Jun-85	1,025	1,495	147	1,642	617	62.4
Dec-85	1,204	1,589	150	1,739	535	69.2
Jan-86	1,110	1,448	146	1,594	484	69.6
Jun-86	909	1,473	137	1,610	701	56.5
Dec-86	1,128	1,556	131	1,687	559	66.9
Jan-87	1,146	1,508	128	1,636	490	70.0
Jun-87	1,008	1,496	130	1,626	618	62.0
Dec-87	1,109	1,468	127	1,595	486	69.5
Jan-88	1,197	1,459	124	1,583	386	75.6
Jun-88	1,062	1,545	121	1,666	604	63.7
Dec-88	1,171	1,644	119	1,763	592	66.4
Jan-89	1,216	1,609	126	1,735	519	70.1
Jun-89	1,067	1,539	127	1,666	599	64.0
Dec-89	1,082	1,526	115	1,641	559	65.9
Jan-90	1,168	1,561	109	1,670	502	69.9
Jun-90	1,068	1,582	110	1,692	624	63.1
Dec-90	1,152	1,574	112	1,686	534	68.3
Jan-91	1,293	1,741	94	1,835	542	70.5
Jun-91	1,114	1,720	92	1,812	698	61.5
Dec-91	1,413	1,922	93	2,015	602	70.1
Jan-92	1,592	1,996	156	2,152	560	74.0
Jun-92	1,549	1,946	152	2,098	549	73.8
Dec-92	1,655	1,917	149	2,066	411	80.1
Jan-93	1,617	1,864	150	2,014	397	80.3
Jun-93	1,456	1,813	141	1,954	498	74.5
Dec-93	1,770	2,080	141	2,221	451	79.7
Jan-94	1,822	2,177	124	2,301	479	79.2
Jun-94	1,703	2,150	120	2,270	567	75.0
Dec-94	1,781	2,171	118	2,289	508	77.8
Jan-95[a]	1,761	2,112	117	2,229	468	79.0
Jun-95[a]	1,654	2,082	118	2,200	546	75.2
Dec-95[a]	1,788	2,183	118	2,301	513	77.7

[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.

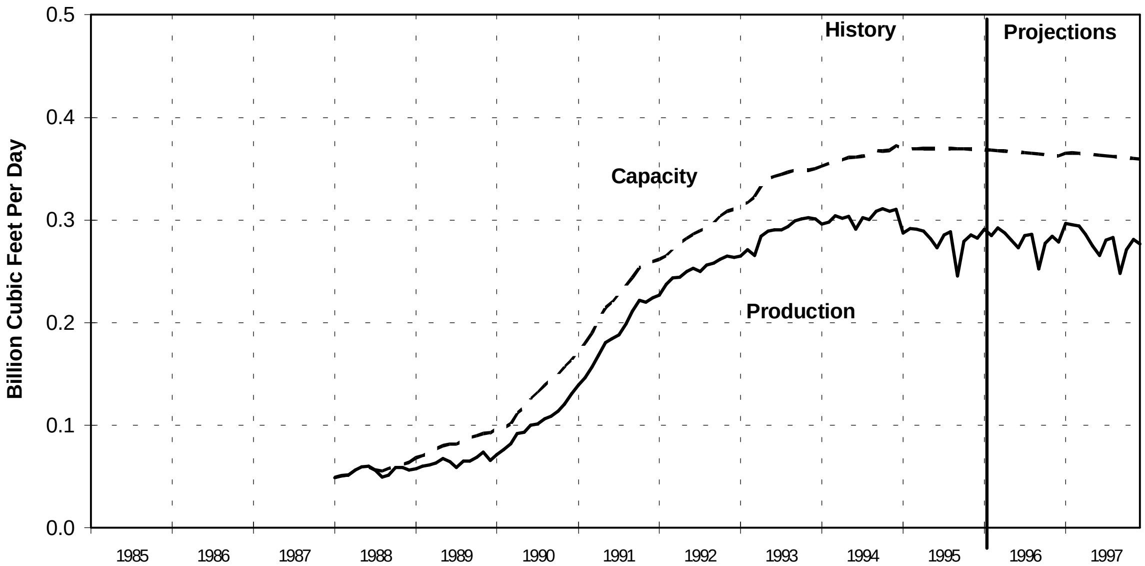
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196.

Table 18. Southeast (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
			Low Case Projection			
Jan-96	1,815	2,150	119	2,269	454	80.0
Jun-96	1,737	2,169	120	2,289	552	75.9
Dec-96	1,821	2,196	116	2,312	491	78.8
Jan-97	1,897	2,168	115	2,283	386	83.1
Jun-97	1,765	2,186	112	2,298	533	76.8
Dec-97	1,933	2,185	109	2,294	361	84.3
			Base Case Projection			
Jan-96	1,815	2,150	119	2,269	454	80.0
Jun-96	1,737	2,169	120	2,289	552	75.9
Dec-96	1,820	2,213	118	2,331	511	78.1
Jan-97	1,895	2,186	118	2,304	409	82.2
Jun-97	1,765	2,254	117	2,371	606	74.4
Dec-97	1,903	2,325	116	2,441	538	78.0
			High Case Projection			
Jan-96	1,815	2,150	119	2,269	454	80.0
Jun-96	1,737	2,169	120	2,289	552	75.9
Dec-96	1,819	2,219	120	2,339	520	77.8
Jan-97	1,895	2,193	121	2,314	419	81.9
Jun-97	1,765	2,300	120	2,420	655	72.9
Dec-97	1,880	2,446	121	2,567	687	73.2

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

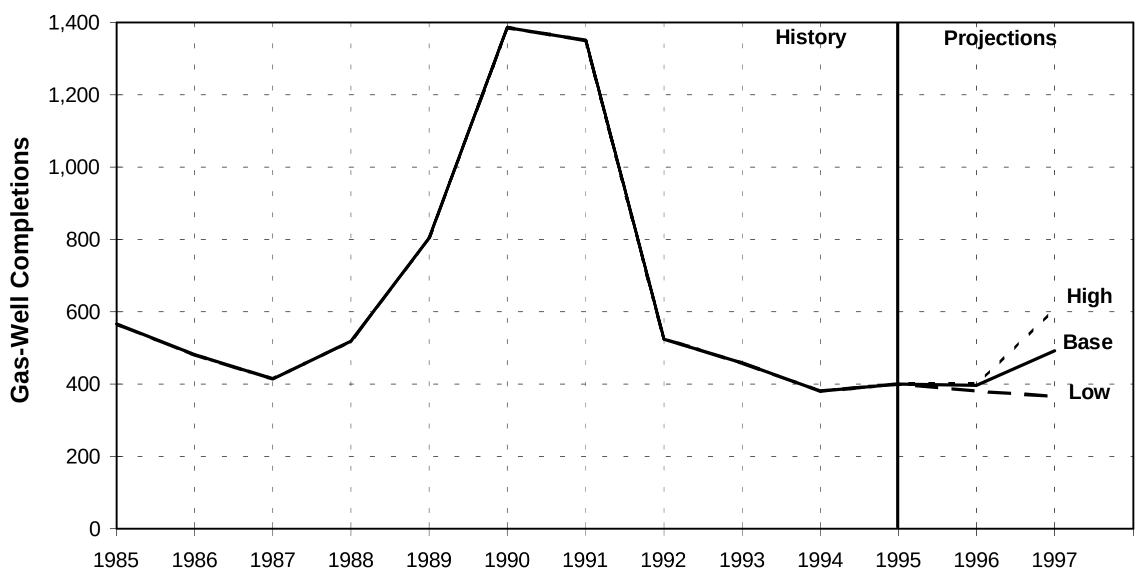
Figure 35. Southeast (Excluding Gulf of Mexico OCS) Dry Coalbed Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C11016. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

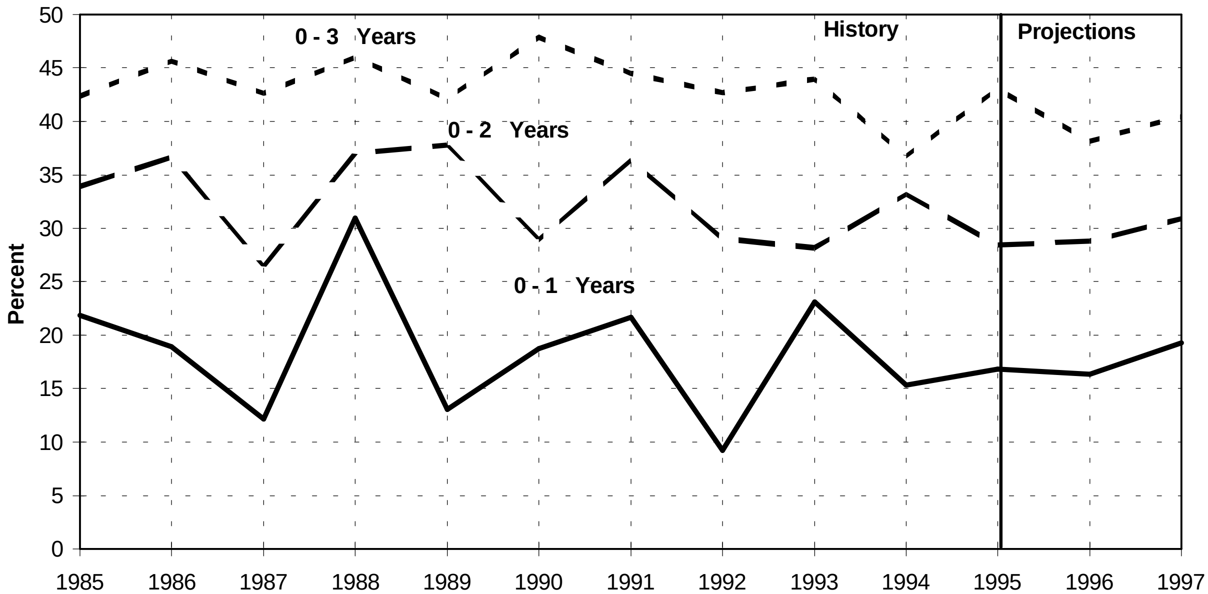
Figure 36. Southeast (Excluding Gulf of Mexico OCS) Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 37. Percent of Total Wellhead Productive Capacity of Southeast (Excluding Gulf of Mexico) Gas Wells by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

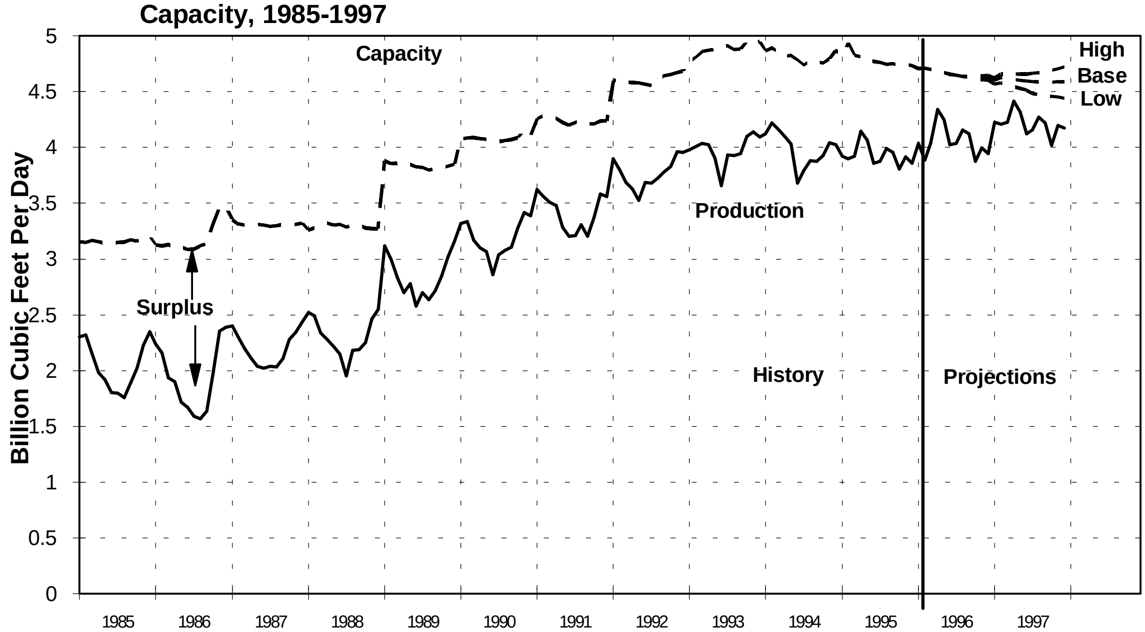
Rocky Mountains

The Rocky Mountains area includes Colorado, Montana, North Dakota, Utah, and Wyoming. The area is diverse and geologically complex, with many low permeability formations.

Coalbed gas produced in Colorado was about 11 percent of the State's total dry gas produced in 1990, 17 percent in 1991, 26 percent in 1992, 32 percent in 1993, and 40 percent in 1994. {12} Coalbed gas-well completions in Colorado and Wyoming were treated separately from conventional gas-well completions in this report. Coalbed gas capacity has shown an increase in the last few years (Figure 39).

The following pages include Tables 19 and 20 and Figures 38 through 41, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 38. Rocky Mountains Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history is based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 19. Rocky Mountains Dry Gas Production and Wellhead Productive Capacity, 1985-1995
(Million Cubic Feet Per Day)

		Dry Gas Productive Capacity				
Month-Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	2,306	2,520	634	3,154	848	73.1
Jun-85	1,804	2,508	636	3,144	1,340	57.4
Dec-85	2,352	2,597	609	3,206	854	73.4
Jan-86	2,240	2,475	650	3,125	885	71.7
Jun-86	1,671	2,488	600	3,088	1,417	54.1
Dec-86	2,389	2,910	562	3,472	1,083	68.8
Jan-87	2,402	2,570	785	3,355	953	71.6
Jun-87	2,025	2,545	761	3,306	1,281	61.3
Dec-87	2,437	2,561	763	3,324	887	73.3
Jan-88	2,523	2,457	802	3,259	736	77.4
Jun-88	2,147	2,508	804	3,312	1,165	64.8
Dec-88	2,552	2,518	754	3,272	720	78.0
Jan-89	3,117	2,973	909	3,882	765	80.3
Jun-89	2,580	2,952	873	3,825	1,245	67.5
Dec-89	3,155	2,990	861	3,851	696	81.9
Jan-90	3,318	3,011	1,061	4,072	754	81.5
Jun-90	2,861	3,022	1,045	4,067	1,206	70.3
Dec-90	3,390	3,097	1,015	4,112	722	82.4
Jan-91	3,626	3,157	1,102	4,259	633	85.1
Jun-91	3,207	3,125	1,077	4,202	995	76.3
Dec-91	3,559	3,191	1,048	4,239	680	84.0
Jan-92	3,899	3,519	1,080	4,599	700	84.8
Jun-92	3,685	3,516	1,051	4,567	882	80.7
Dec-92	3,956	3,675	1,009	4,684	728	84.5
Jan-93	3,977	4,006	765	4,771	794	83.4
Jun-93	3,655	4,142	770	4,912	1,257	74.4
Dec-93	4,091	4,212	736	4,948	857	82.7
Jan-94	4,123	4,219	646	4,865	742	84.7
Jun-94	3,680	4,154	634	4,788	1,108	76.9
Dec-94	4,024	4,254	617	4,871	847	82.6
Jan-95[a]	3,921	4,204	629	4,833	912	81.1
Jun-95[a]	3,858	4,163	609	4,772	914	80.8
Dec-95[a]	3,862	4,120	615	4,735	873	81.6

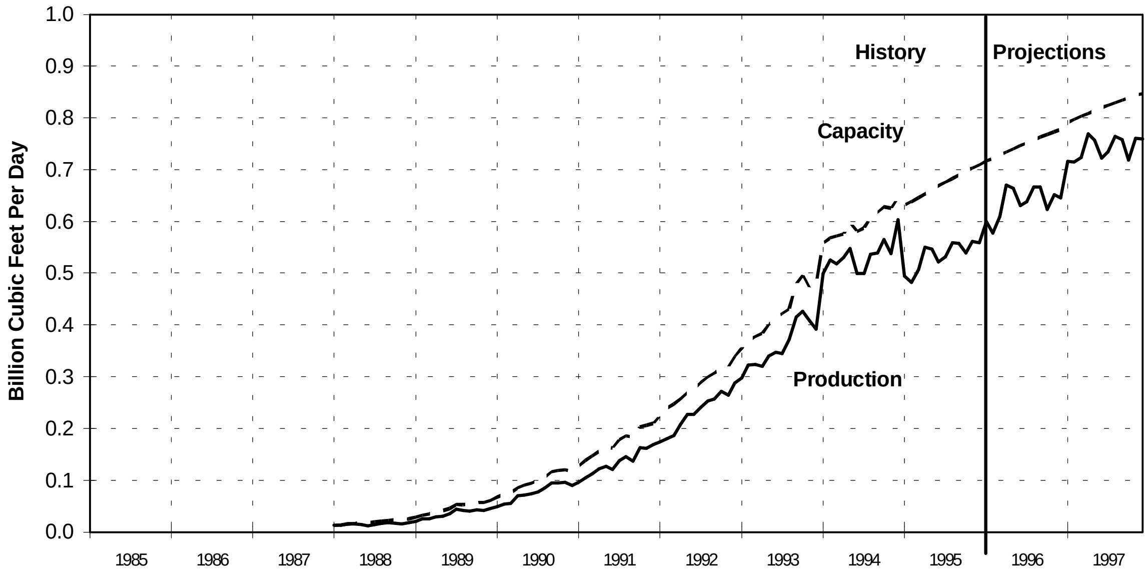
[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.
Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196.

Table 20. Rocky Mountains Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
	Low Case Projection					
Jan-96	4,038	4,086	622	4,708	670	85.8
Jun-96	4,027	4,031	624	4,655	628	86.5
Dec-96	3,946	4,001	603	4,604	658	85.7
Jan-97	4,231	3,973	596	4,569	338	92.6
Jun-97	4,124	3,934	581	4,515	391	91.3
Dec-97	4,240	3,880	562	4,442	202	95.5
	Base Case Projection					
Jan-96	4,038	4,086	622	4,708	670	85.8
Jun-96	4,027	4,031	624	4,655	628	86.5
Dec-96	3,944	4,015	615	4,630	686	85.2
Jan-97	4,226	3,988	613	4,601	375	91.8
Jun-97	4,124	3,991	604	4,595	471	89.7
Dec-97	4,175	3,994	596	4,590	415	91.0
	High Case Projection					
Jan-96	4,038	4,086	622	4,708	670	85.8
Jun-96	4,027	4,031	624	4,655	628	86.5
Dec-96	3,942	4,020	625	4,645	703	84.9
Jan-97	4,226	3,995	629	4,624	398	91.4
Jun-97	4,124	4,032	624	4,656	532	88.6
Dec-97	4,123	4,097	623	4,720	597	87.4

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

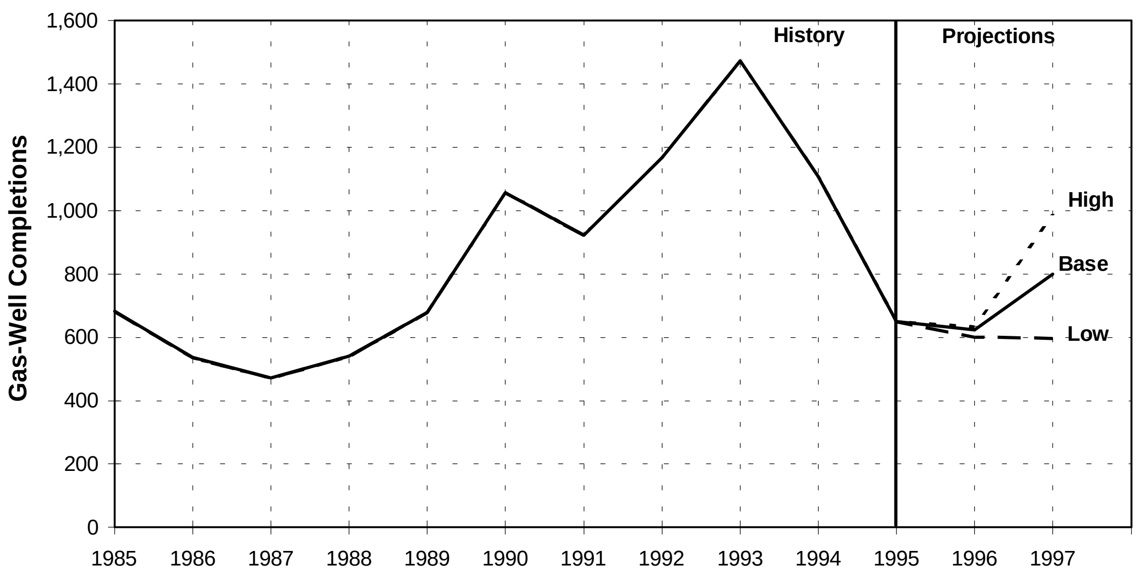
Figure 39. Rocky Mountains Dry Coalbed Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C11016. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

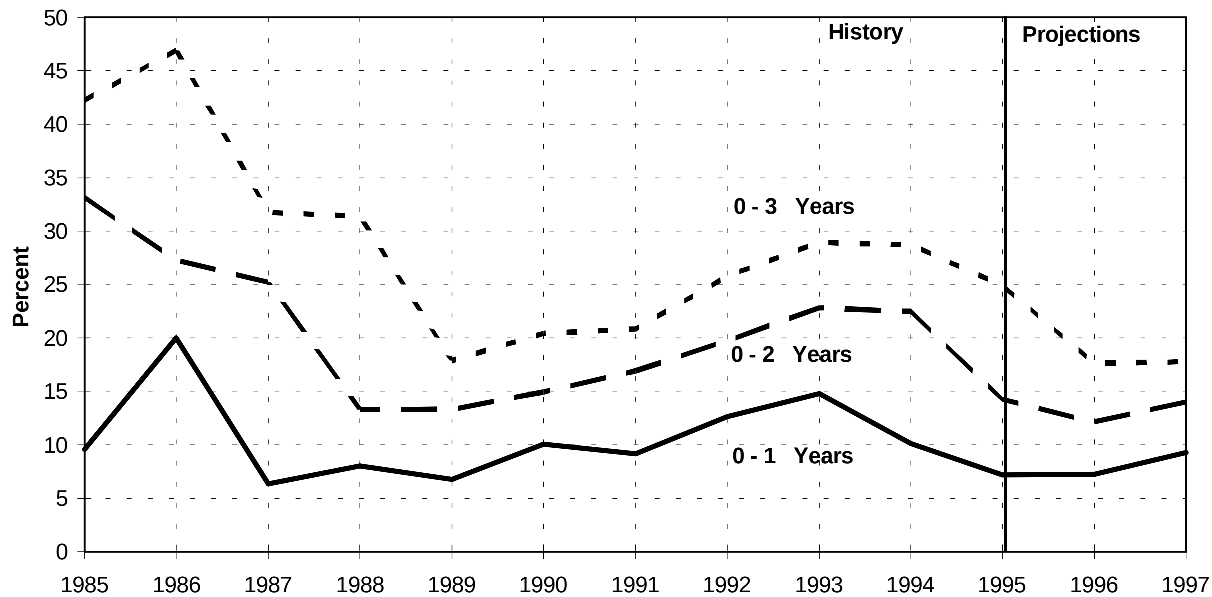
Figure 40. Rocky Mountains Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Figure 41. Percent of Total Wellhead Productive Capacity of Rocky Mountains Gas Wells by Well Age, 1985-1997 (Base Case)



Sources: History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Projections: Model GASCAP94 C110196.

Eighteen States

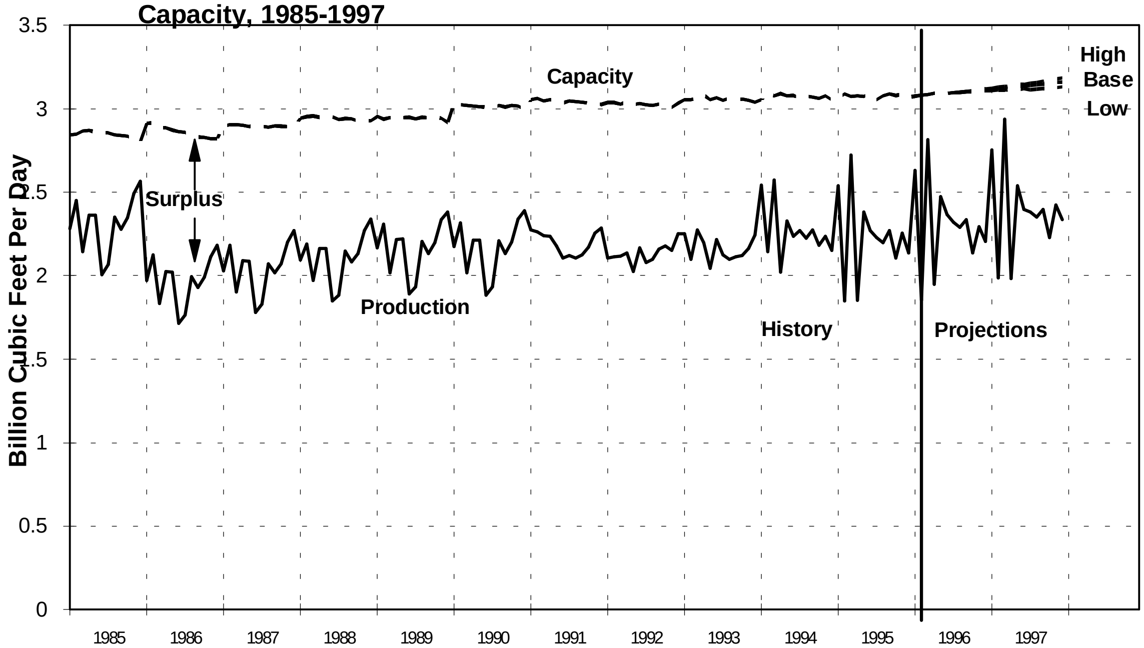
The remaining producing 18 States were considered as one group. The 18 States are:

- Arizona
- Florida
- Illinois
- Indiana
- Kentucky
- Maryland
- Michigan
- Missouri
- Nebraska
- Nevada
- New York
- Ohio
- Oregon
- Pennsylvania
- South Dakota
- Tennessee
- Virginia
- West Virginia.

Data are limited for this group of States, and only 3 of the 18 States are included in Dwight's: Nebraska, Oregon, and South Dakota. Production data are available from EIA for each of the 18 States but not by well completion. The 18 States are:

The following pages include Tables 21 and 22 and Figures 42 and 43, which provide historical and projected production, productive capacity, and gas-well completions added.

Figure 42. Eighteen States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1985-1997



Note: Production projection plotted for base case only. The 1995 estimated history based on Model GASCAP94 C110196 projections.

Sources: Production History: Energy Information Administration, Office of Oil and Gas and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196. Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196.

Table 21. Eighteen States Dry Gas Production and Wellhead Productive Capacity, 1985-1995
(Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
Jan-85	2,281	2,642	203	2,845	564	80.2
Jun-85	2,007	2,637	216	2,853	846	70.3
Dec-85	2,565	2,592	208	2,800	235	91.6
Jan-86	1,970	2,700	213	2,913	943	67.6
Jun-86	1,716	2,662	201	2,863	1,147	59.9
Dec-86	2,182	2,631	189	2,820	638	77.4
Jan-87	2,029	2,680	218	2,898	869	70.0
Jun-87	1,781	2,677	221	2,898	1,117	61.5
Dec-87	2,272	2,675	219	2,894	622	78.5
Jan-88	2,095	2,729	214	2,943	848	71.2
Jun-88	1,848	2,724	227	2,951	1,103	62.6
Dec-88	2,341	2,722	207	2,929	588	79.9
Jan-89	2,166	2,717	237	2,954	788	73.3
Jun-89	1,890	2,721	228	2,949	1,059	64.1
Dec-89	2,382	2,725	194	2,919	537	81.6
Jan-90	2,173	2,772	264	3,036	863	71.6
Jun-90	1,883	2,770	239	3,009	1,126	62.6
Dec-90	2,390	2,770	226	2,996	606	79.8
Jan-91	2,275	2,800	253	3,053	778	74.5
Jun-91	2,105	2,795	239	3,034	929	69.4
Dec-91	2,285	2,781	244	3,025	740	75.5
Jan-92	2,104	2,781	255	3,036	932	69.3
Jun-92	2,166	2,772	260	3,032	866	71.4
Dec-92	2,253	2,776	257	3,033	780	74.3
Jan-93	2,253	2,790	266	3,056	803	73.7
Jun-93	2,217	2,797	269	3,066	849	72.3
Dec-93	2,245	2,787	252	3,039	794	73.9
Jan-94	2,541	2,791	262	3,053	512	83.2
Jun-94	2,238	2,779	301	3,080	842	72.7
Dec-94	2,153	2,778	276	3,054	901	70.5
Jan-95[a]	2,537	2,783	287	3,070	533	82.6
Jun-95[a]	2,270	2,799	286	3,085	815	73.6
Dec-95[a]	2,136	2,825	244	3,069	933	69.6

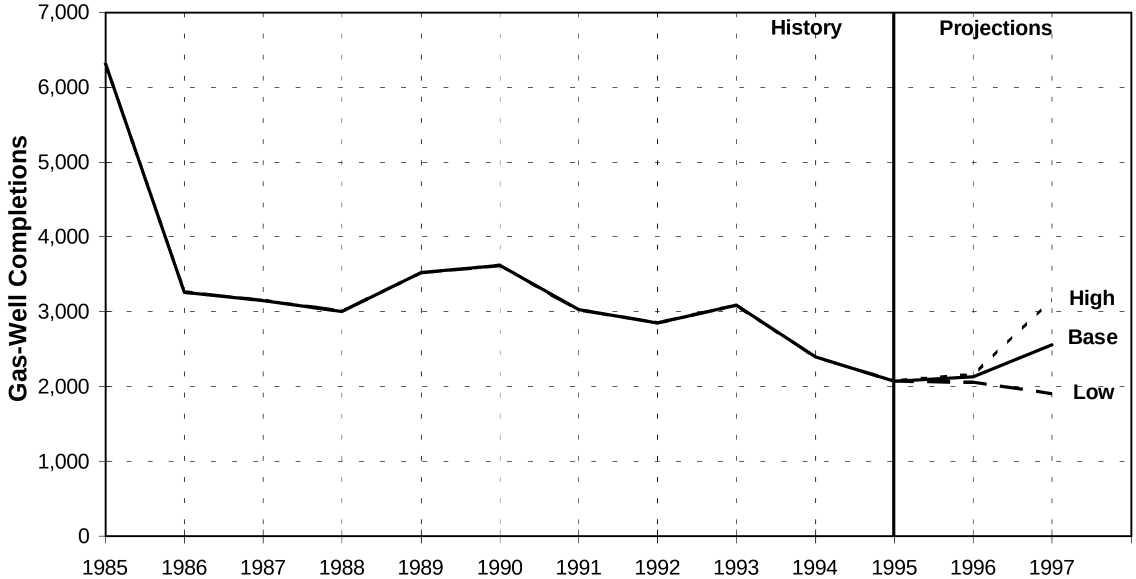
[a] The 1995 estimated history is based on Model GASCAP94 C110196 projections and Baker Hughes rig counts.
Sources: Production History: Energy Information Administration, Office of Oil and Gas and Model GASCAP94 C110196. Productive Capacity: Model GASCAP94 C110196.

Table 22. Eighteen States Dry Gas Production and Wellhead Productive Capacity Projections, 1996-1997 (Million Cubic Feet Per Day)

Month-Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Utilization (percent)
		Low Case Projection				
Jan-96	2,630	2,829	247	3,076	446	85.5
Jun-96	2,366	2,847	246	3,093	727	76.5
Dec-96	2,206	2,872	236	3,108	902	71.0
Jan-97	2,756	2,876	233	3,109	353	88.6
Jun-97	2,398	2,893	226	3,119	721	76.9
Dec-97	2,371	2,914	217	3,131	760	75.7
		Base Case Projection				
Jan-96	2,630	2,829	247	3,076	446	85.5
Jun-96	2,366	2,847	246	3,093	727	76.5
Dec-96	2,205	2,872	241	3,113	908	70.8
Jan-97	2,754	2,877	240	3,117	363	88.4
Jun-97	2,398	2,900	235	3,135	737	76.5
Dec-97	2,335	2,930	230	3,160	825	73.9
		High Case Projection				
Jan-96	2,630	2,829	247	3,076	446	85.5
Jun-96	2,366	2,847	246	3,093	727	76.5
Dec-96	2,204	2,873	245	3,118	914	70.7
Jan-97	2,754	2,878	246	3,124	370	88.2
Jun-97	2,398	2,905	242	3,147	749	76.2
Dec-97	2,306	2,944	240	3,184	878	72.4

Sources: Production Projections: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996, and Model GASCAP94 C110196. Productive Capacity Projections: Model GASCAP94 C110196.

Figure 43. Eighteen States Gas-Well Completions Added During Year, 1985-1997



Note: The 1995 estimated history is based on Drilling Rig Model projections and Baker Hughes rig counts. Completions include recompletions in new producing zones.

Sources: History: Energy Information Administration, Office of Oil and Gas. Estimates of gas-well completions based on API well completion data. Projections: Model GASCAP94 C110196.

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Appendix A

Methodology

Methodology

This appendix generally describes the methodology used to estimate the gas productive capacity of conventional and coalbed gas wells and oil wells for each State or area. For more detail, see Appendix B or the *Wellhead Gas Productive Capacity (GASCAP) Model Documentation*.{18} Lack of back-pressure test data and gas-in-place estimates by reservoir for a sizeable portion of the lower 48 States precluded doing conventional kinds of gas-well productive capacity studies that have been done in the past for specific States and areas. Because only production data were available for the lower 48 States, another technique had to be used. The lower 48 States were divided into States and multi-States for which production data by well is listed by Dwight's EnergyData, Inc. (Dwight's). The Gulf of Mexico Outer Continental Shelf (OCS), and each of six States (Texas, Louisiana, California, Kansas, New Mexico, and Oklahoma) were studied individually. Five States were grouped together as the Rocky Mountains area: Colorado, Montana, North Dakota, Utah, and Wyoming. A Southeast area consisted of Alabama, Arkansas, and Mississippi. An additional 18 States were studied as a group by using aggregate EIA monthly production data and API drilling statistics. They are: Arizona, Florida, Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, Virginia, and West Virginia.

The basis of the initial data preparation is the calendar year. Monthly and annual gas-well production data from Dwight's. and EIA data series are not always the same; however, the differences in production between the two sources has generally been small. Annual adjustment factors were developed and applied to Dwight's EnergyData Inc. data to ensure that the difference between the production data from the two sources was eliminated on an annual basis. However, the historical monthly production data presented in this report may still differ from the monthly data published in other EIA publications.

Gas-Well Gas Productive Capacity

The first step in estimating gas-well productive capacity is to obtain the production for each gas-well completion in every State or multi-State area by month. This was available from Dwight's. data files for all States and areas except for the 18 States previously identified where monthly production data were available from EIA but not by well completion. Data edits were performed on the historical monthly data.

The historical average vintage productive capacities on a per well basis are then established and projected using the estimated number of monthly new wells going on production. The estimated 1995 history and the projected 1996 and 1997 productive capacities (*low, base,* and *high* cases) are based on the *Wellhead Productive Capacity Model* (GASCAP) described in Appendix B.

Historical Production

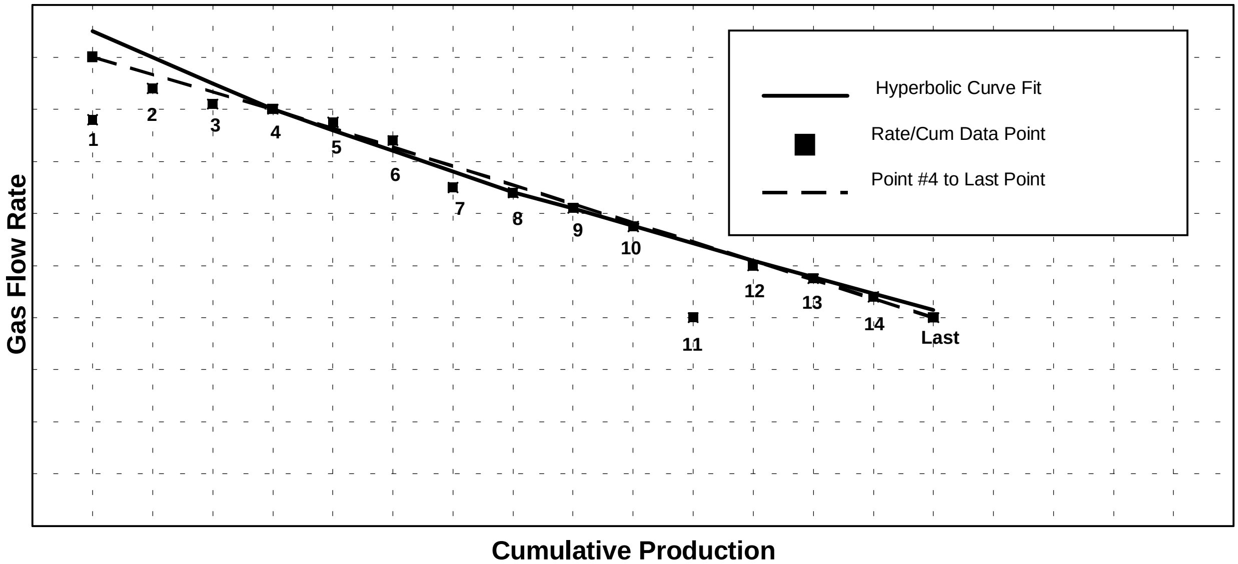
The monthly gas-well production belonging to each State or area vintage is tabulated and plotted versus cumulative production. Vintage gas-well production is defined as the production from all well completions in a State or area with first production beginning in the same calendar year. For example, production from all well completions going on stream for the first time in Texas in 1972 would be called the Texas 1972 vintage gas-well production.

Historical Productive Capacity

A peak production rate is determined each year for every vintage in each State or area. The peak-rate selected is the sum of all of the gas-well completion peak-rates within a particular vintage year without regard to the month in which the gas-well completion peak-rate occurred. It is assumed that if a gas-well completion in a vintage produced at a maximum rate during any month of the year, the gas-well completion should have been capable of at least this production rate in prior months.

After the annual peak rates are determined, they are screened (Figure A1) to eliminate those that are not near capacity. The first peak rate in each vintage is eliminated because not all of the gas-well completions have produced gas for the entire first year. Furthermore, beginning with the last annual point, each point is compared with the previous year's point

Figure A1. Screening Process



Note: Point	Reason for Point Rejection
1	Point 1 Always omitted
2 & 3	Falls below straight line connecting 4th and last points
7	More than one standard deviation below the estimated value
11	Point 12 is larger

Source: Energy Information Administration, Office of Oil and Gas.

until the initial point is reached. If the previous point is higher, it is retained. If it is lower, it is rejected (point 11). This is done because a rate versus cumulative production curve should show a decline when the wells are producing near productive capacity. Next, a straight line connected by the fourth and last points is extended backward through the second and third points. The second and third points are rejected if these points fall below the straight line. This process is repeated using the last and third data points to check the second data point. If the data points fall below both straight lines, it is assumed that the low peak rates could be due to reasons other than physical limitations of the wells--for example, low demand, proration, or temporary mechanical problems.

The next step is to fit the remaining points with a hyperbolic curve. A hyperbolic curve fit is chosen because it is the decline curve most often encountered. For example, Figure A2 shows a hyperbolic fit for the peak rates versus cumulative gas production for the 1982 vintage wells in the Gulf of Mexico OCS. Initial estimates are made for the initial rate (q_I; the Y - intercept), and ultimate recovery (G_{ul}; the X - intercept). Although this curve might appear to be exponential, there is a slight curvature. The exponent B is close to one (1), indicating that the curve comes close to being an exponential curve.

The rate versus cumulative production relationship{19} for the hyperbolic decline is:

$$G_p = \frac{q_i^b}{D_i(1-b)} \left(q_i^{\,1-b} - q^{1-b}\right) \,, \qquad \text{(A1)}$$

where

G_p = cumulative gas produced, thousand cubic feet

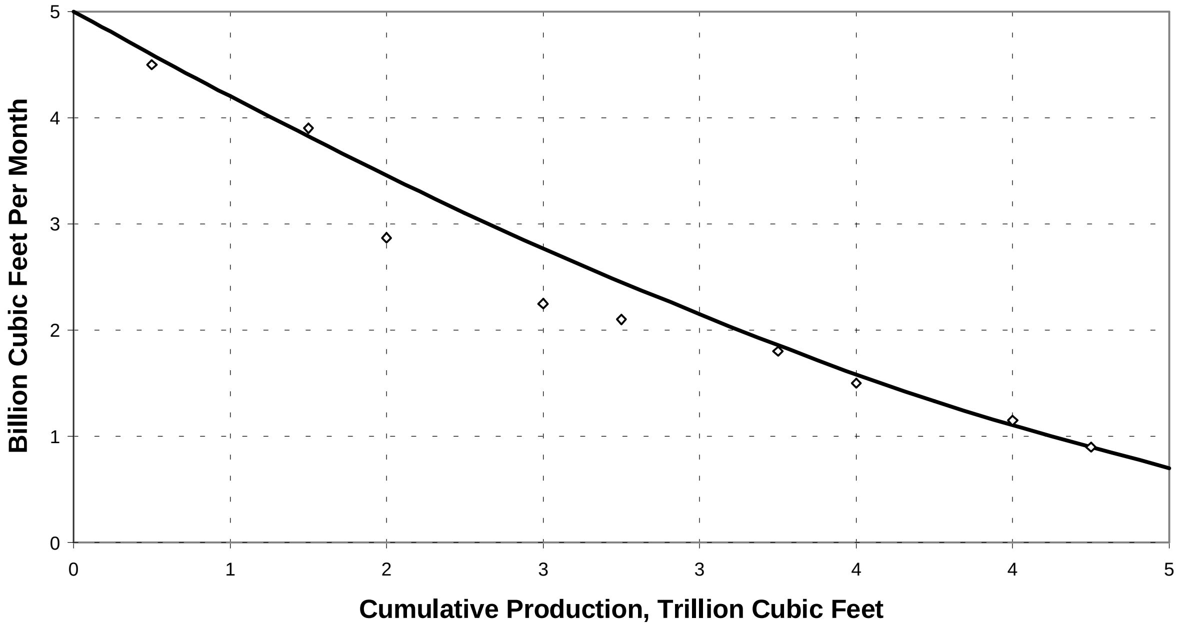
q_i = initial gas flow rate at capacity, thousand cubic feet per day

q = gas flow rate at capacity, thousand cubic feet per day

D_i = initial daily decline rate

b = hyperbolic decline exponent.

Figure A2. Gross Gas-Well Gas Productive Capacity for the Gulf of Mexico OCS 1982 Vintage



Source: Energy Information Administration Model GASCAP C051995, based on production data from Dwight's Energydata, Inc.

In equation (A1), cumulative gas produced, G_p, becomes the ultimate recoverable gas, G_{ul}, when the flow rate, q, is at abandonment conditions. Assuming that the flow rate, q, at abandonment conditions is zero, equation (A1) becomes:

$$G_{ul} = \frac{q_i}{D_i(1-b)} \quad . \tag{A2}$$

Rearranging (A1),

$$q = \left[\, q_i^{1-b} - \frac{D_i\,(1-b)}{q_i^{b}}\, G_p \,\right]^{1/(1-b)} \quad . \tag{A3}$$

Simplifying (A3),

$$q = q_i \left[1 - \frac{D_I(1-b)}{q_i} G_p\right]^{1/(1-b)} \quad . \tag{A4}$$

Substituting (A2) in (A4),

$$q = q_i \left[1 - \frac{G_p}{G_{ul}}\right]^{1/(1-b)} \quad . \tag{A5}$$

Substituting B for $\frac{1}{1-b}$,

$$q = q_i \left[1 - \frac{G_p}{G_{ul}}\right]^{B} \quad . \tag{A6}$$

Equation (A6) is used to describe the hyperbolic decline of the peak flow rates of each vintage curve.

In 1956, J.J. Arps in his report entitled *Estimation of Primary Oil Reserves* {19} *state that W.W. Cutler, Jr., of the U.S. Bureau of Mines* {20} indicated that most decline curves normally encountered are of the hyperbolic type, with values for the exponent b between 0 and 0.7, with the majority falling between 0 and 0.4. This means that the values of the exponent B are between 1.0 and 3.3, with the majority between 1.0 and 1.7. The accepted range for B in the GASCAP model is from 1.001 to 3.0. The lower value of 1.001 was chosen rather than 1.0 because a value of 1.0 used in equation (A9) would result in division by 0, a forbidden operation. Values of B greater than 3.0 tend to give unrealistically large values of G_{ul}. Also, the raw production data are often distorted by low gas demand. This causes an apparent very rapid production rate decline and an accompanying large B that is not based on the physical capability of wells to produce gas. A data screening algorithm was used during the decline curve fitting process to identify low production rate data points caused by low demand. The highest B allowed during a curve fit to initiate this process was 3.0.

Productive capacity rather than peak rate is desired for the vintage curves. However, only the vintage curve's peak rate could be obtained. Peak rate is close to productive capacity if the demand for gas is much higher than normal for at least 1 month during the year. In the model, demand is defined as the monthly gas volume produced for the lower 48 States, State / areas, or vintage. If demand were to remain low for every month of the year, the highest peak rate for the year would be lower than the actual productive capacity.

Another screening process is performed to eliminate low rates that could be a result of low demand. If an actual or observed point is more than one standard deviation lower than the corresponding calculated value on the vintage curve, the actual point is rejected. The remaining data points are then refitted keeping B constant and allowing q_i and G_{ul} to vary. This process is applied to all vintages except the last three.

The initial rates (q_i) for the last three vintage years are calculated independently of the regression analysis. The q_I for the last historical vintage year is an historical average on a per well basis, as described later. The q_i for the previous two vintages is determined by averaging the ratio between the calculated q_i and the peak rate in the second year of production. These average ratios are taken for the 7 years prior to the last 3 years, and are multiplied by the peak rate in the second year of production to provide a fixed q_i.

For the projections of capacity for vintage curves beginning with the last historical vintage year, the values of q_i, G_p, and the corresponding q are needed on a well completion basis and are obtained by averaging these values for the last 3 historical vintage years, not including the last one. The gas flow rate, q_ν, is the average of the per-well capacities for December of the second production year. $G_{p\nu}$ is the average gas produced per well through December of the second production year. $G_{ul\nu}$ is the average ultimate recovery on a per well completion basis and is obtained by substituting the previously derived values for $q_{i\nu}$, $G_{p\nu}$, and q_ν in the following equation, which is a rearrangement of equation (A6) after each term by the number of gas-well completions, ν,

$$G_{ul\nu} = \frac{G_{p\nu}}{1 - (q_\nu / q_{i\nu})^{1/B}} \quad . \qquad \text{(A7)}$$

The q_i and G_{ul} on a per-well completion basis are multiplied by the number of new well completions in each year to obtain the q_i and G_{ul} for each year.

Projections of Productive Capacity

Projected Productive Capacity of Old Vintage Wells

After the historical productive capacity vintage curves are developed through the last historical data year, they are projected for 3 years. Productive capacity curves also had to be developed for all well completions going on stream in these projected years. It is assumed that the productive capacity for the total well completions beginning production during the vintage year will increase throughout the vintage year and will start to decline the next year.

To start the projection routine, the flow rate at capacity is calculated from each vintage for each month starting in January of the first projected year. The production for each vintage for any month is calculated by allocating the expected demand to each vintage based on the capacity of each vintage. The cumulative production for each vintage is the sum of the cumulative production at the beginning of the month and the allocated production. The new well completions (well completions going on production in each month for the first time) are used for the current vintage capacity calculations.

All old vintages are projected for 3 years. The production rate as a function of cumulative production, G_p, is given by equation (A6). The production rate can also be written as a function of time, t, as described by Arps, although in his formulation, $B = \frac{1}{(1-b)}$:

$$q = q_i \left[1 + \frac{q_I (B-1)\, t}{G_{ul}}\right]^{B/(1-B)} \quad , \qquad \text{(A8)}$$

Equation (A8) is the hyperbolic equation that describes production rate decline as a hyperbolic function of time.

The time, *t*, that corresponds to the vintage productive capacity at the beginning of the month is calculated by solving equation (A8):

$$t = \frac{G_{ul}\,[(q/q_i)^{(1-B)/B} - 1]}{(B-1)\,q_i}\ , \qquad \text{(A9)}$$

where *q* is the flow rate at capacity (productive capacity) at the beginning of the month. The number of days in the month are added in order to step forward and calculate the vintage productive capacity at the beginning of the next month.

The maximum possible cumulative production to the end of the month is calculated by using the following equation, which is a rearrangement of equation (A6):

$$G_p = G_{ul}\,[1-(q/q_i)^{1/B}]\ . \qquad \text{(A10)}$$

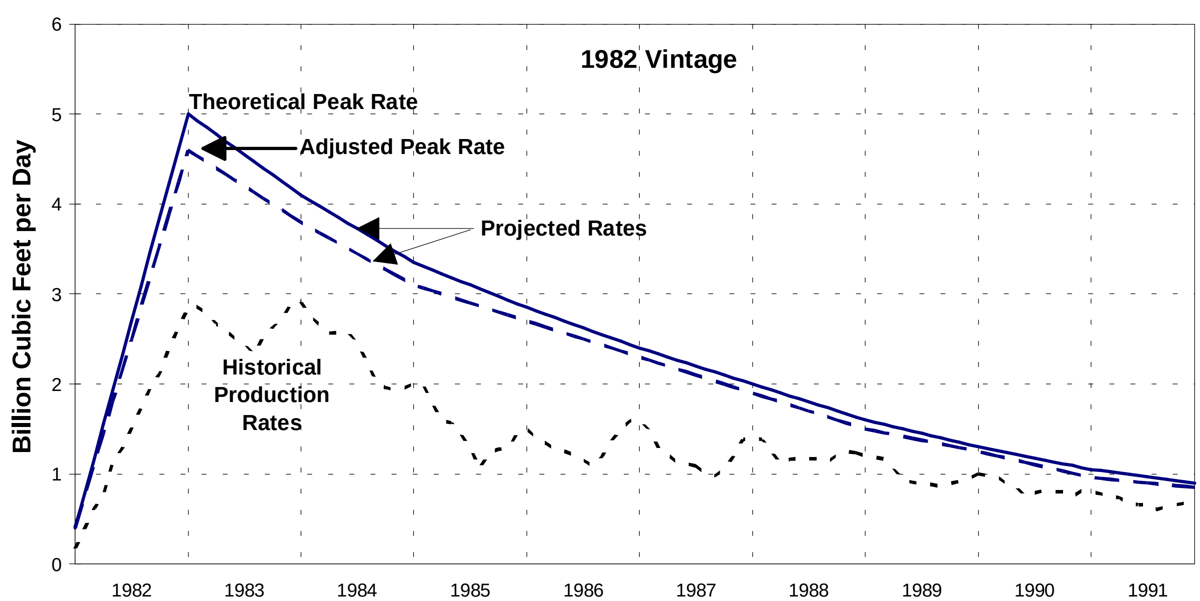
Furthermore, the productive capacities for the nine areas are multiplied by load factors. The load factors are applied because gas-well completions are frequently shut-in because of mechanical problems. In the model, annual load factors for the last 10 historical years are derived by dividing the annual production from all gas-well completions producing in December of a specific year by the annual production from all gas-well completions that produced in any month during the same year. The load factor for each area is obtained by taking an average of the 10 annual load factors.

The cumulative gas produced to the beginning of a specific month is subtracted from the maximum possible cumulative gas produced at the end of the month to yield maximum productive capacity for the month for each vintage.

The productive capacities for each vintage year are summed and the demand is allocated to each vintage by its percentage of the total capacity. Next, the allocated production is added to the cumulative production at the beginning of a specific month for each vintage, and the process is repeated, starting with the calculation of time (*t*) in equation (A9).

Figure A3 displays the historical production rates, the adjusted peak rate, the theoretical peak capacity rate, and the projected rates for vintage year 1982 for the Gulf of Mexico OCS.

Figure A3. Capacity and Production Rates for the Gulf of Mexico OCS 1982 Vintage Year



Sources: Production: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Theoretical and adjusted peaks: Model GASCAP93 C060194.

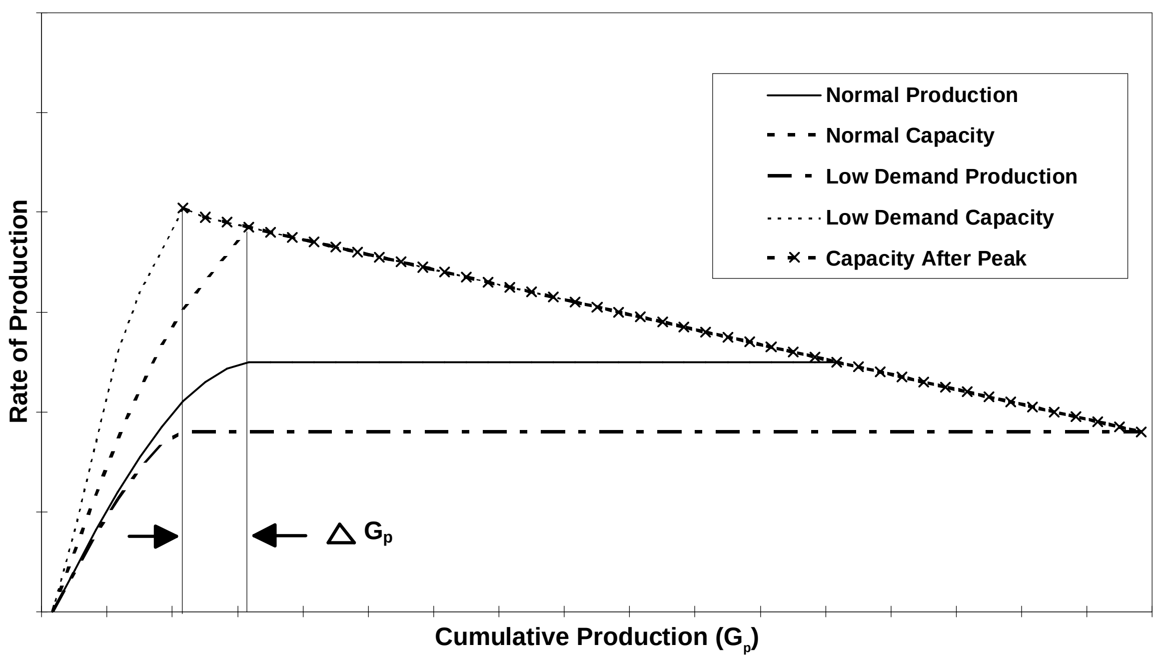
Projected Productive Capacity of New Vintage Wells

Demand is defined for this model to be the volume of gas required from gas-well completions. Productive capacity is defined as the maximum volume of gas a gas-well can produce for a month.

If demand approaches the productive capacity of the old wells, the new wells (i.e., wells with near original capacity) will be called upon to produce at higher daily rates. This will cause the capacities of wells brought on in January to begin a higher rate of decline than normal (what usually happens in the historical data). Therefore, the productive capacity of wells brought on in January will be significantly less than their initial capacity, and the cumulative production (G_p) will be higher at the end of the year. If, however, demand decreases as a percentage of productive capacity, the new wells will not be required to produce at as high a rate as is normal. Their productive capacity will be greater than normal, and their corresponding cumulative production will be less at the end of the first year (Figure A4). A theoretical hyperbolic type curve illustrates this discussion. The difference in the cumulative production (G_p) is the difference between the annual production under normal demand (Case 1) and low demand (Case 2) at the end of the first year. Since capacity has been defined as a function of cumulative production, the difference in cumulative production for a low demand year or a high demand year can be determined by subtracting the actual cumulative production from the historical normal cumulative production (mean production rates for all previous vintage years per well completion). The capacity can be adjusted to account for low (or high) demands during the first year. This is done on a monthly basis for the first year of production for each new vintage year. The difference in cumulative production at the end of the first year is also used to adjust the cumulative production and, therefore, the capacity in all subsequent years.

Monthly productive capacity for a new vintage year is a function of the wells completed during the month plus the amount contributed by wells completed earlier in the year. For each month, the productive capacity for wells completed that month is assumed to be one-half of the month's well completions times the average initial rate (q_i) per well for the previous three vintage years (obtained as described earlier). The productive capacity for earlier wells is determined as a function of normal cumulative production modified by the need to

Figure A4. Theoretical Hyperbolic Type Curve for Production and Capacity



Source: Energy Information Administration, Office of Oil and Gas.

meet the allocated demand from the wells completed in the prior months.

The equation is as follows:

$$q_k = (0.5\,\nu_k + \sum_{j=0}^{k-1} \nu_j)\left(\frac{q_i}{\nu}\right)\left[1 - \frac{\sum_{j=0}^{k-1} \Delta G_{p_j}}{\left(\frac{G_{ul}}{\nu}\right)\sum_{j=0}^{k-1} \nu_j}\right]^B, \quad \text{(A11)}$$

where

q_k = productive capacity in month k, thousand cubic feet per day

ν_k = number of gas-well completions for month k

ν = total number of new gas-well completions for the vintage year

q_I = initial flow capacity, thousand cubic feet per day

ΔG_p = difference between the gas produced during the month and the amount of gas that would have been produced under normal or average conditions, thousand cubic feet

G_{ul} = ultimate gas recovery when q=0, thousand cubic feet

k = month 1,2,....12

j = jth term in the series

$\sum \nu_j$ = cumulative number of gas-well completions through the previous month.

The normal cumulative production is the average historical cumulative production per well of preceding vintages multiplied by the new well completions.

Projected Productive Capacity for the 18 States

Because production and well counts by vintage year are not available for 15 of the 18 States, a different approach is taken for this group of States. Monthly peak rates are determined from monthly gas-well production data obtained from the Natural Gas Monthly, and the number of new well completions is determined from the API drilling statistics.

The following equation describes the current year's productive capacity as a function of last year's productive capacity and productive capacity from wells brought on in the last 12 months or during the last year.

$$q_{pk(m)} = q_{pk(m-1)} \exp^{D(G_{p\nu\,(m-1)})} + q_{gi}\,\nu_{m-1}, \quad \text{(A12)}$$

where

m = year

q_{pk} = peak production rate, thousand cubic feet per day

D = decline rate of old production, wells per billion cubic feet

$G_{p\nu}$ = cumulative production per well, billion cubic feet per well

ν = total number of new gas-well completions for the year

q_{gi} = initial gas production rate for new wells, thousand cubic feet per day.

For projection purposes the equation was converted to a monthly basis as follows:

$$q_{pk(m,n)} = q_{pk(m,1)} \exp^{D(G_{p\,(m,n-1)})} + q_{gi}\,\nu_{m,n-1}, \quad \text{(A13)}$$

where

m = year

n = month

$q_{pk(m,n)}$ = peak production rate for year (m) and month (n)

$q_{pk(m,1)}$ = calculated January peak production rate for year (m) used as the starting point to accumulate new well completions for monthly projections

D = decline rate for old production, wells per billion cubic feet

$G_{p(m,n-1)}$ = cumulative production per well, to month n–1 for year (m), billion cubic feet per well

$\nu_{m,n-1}$ = new well completions to month (n–1) for year (m)

q_{gi} = initial production rate for new wells, thousand cubic feet per day.

Oil-Well Gas Productive Capacity

Oil-well gas productive capacity is estimated for the same States and areas as gas-well gas productive capacity. Oil wells are considered to be producing at their normal and full capacity as required by the lease operators and State proration/regulation requirements. Oil-well gas production is a function of oil production and the producing gas-oil ratio (GOR); therefore, the difference between productive capacity and gas production for oil wells was assumed negligible.

Gross gas production from oil wells for each State is available on an annual basis only. Therefore, monthly gross gas production from oil wells from 1985 through 1994 was calculated. The annual GOR is calculated by dividing the annual gross oil-well gas production{13} by the annual oil production.{21} Then the monthly oil production is multiplied by the appropriate GOR. The monthly oil production estimates for each State and area for 1995, 1996, and 1997 were multiplied by the corresponding 1994 GOR to yield the forecast of the monthly oil-well gas productive capacity for 1995, 1996, and 1997.

Coalbed Gas Productive Capacity

Coalbed gas-well completion productive capacity is estimated by using the same basic method as for a conventional gas-well completion.

Coalbed gas-well completion productive capacity data was obtained from Dwight's EnergyData, Inc., Oil and Gas Reports, Richardson, TX. The coalbed gas-well completions were grouped in vintage years, as was done for the conventional gas wells, for New Mexico, Rocky Mountain, and Southeast areas. After an historical review of the vintage data, a typical production profile curve for each area and vintage was produced. All coalbed gas completions commencing production prior to the beginning of 1989 were included in the 1988 vintage. Coalbed gas production prior to 1988 consisted of a few wells scattered over many years which produced at low rates. Including all wells prior to 1989 in vintage 1988 facilitated handling the projections of older completions. Table A1 shows the vintage years for each area, along with the cumulative production and the number of wells included in the vintage year.

Coalbed gas well production curves are quite different from conventional gas well production curves. Coalbed gas production increases during the first few years of the life of the well. The production increase is due to gas desorbing from the water and the coal as the pressure is reduced on the reservoir fluids. Production peaks at upward of five years after initial production before starting to decline. Traditional decline curve analysis and the GASCAP model will not handle these first few years of increasing production. A projection curve was developed to match the production profile of a typical coalbed gas-well completion (Figure A5).

To develop a coalbed gas-well production profile curve, the annual peak production rate versus time for the average completion was plotted for each vintage. A matching curve was then fitted to the annual peak points and extended out to the year where production

Table A1. Coalbed Gas Cumulative Production and Number of Completions by Area for Vintage Years 1988 - 1994

	NEW MEXICO		ROCKY MOUNTAIN		SOUTHEAST	
Vintage Year	Cumulative Production (MMcf)	Number Of Wells	Cumulative Production (MMcf)	Number Of Wells	Cumulative Production (MMcf)	Number Of Wells
1988	185,446	99	92,086	171	102,330	484
1989	394,359	250	80,959	140	68,100	408
1990	468,266	364	96,425	201	150,422	961
1991	503,714	497	120,668	164	105,673	1030
1992	217,150	372	52,676	141	13,109	197
1993	87,875	429	59,526	230	14,006	140
1994	8,315	219	5,127	78	2,029	88

Note: Cumulative Production through December 1994 and vintage 1988 includes all previous completed coalbed gas wells.

Sources: Energy Information Administration, Office of Oil and Gas and Dwight's EnergyData, Inc.

would reach or was expected to reach its maximum. A second matching curve starting at the maximum peak rate was projected to decline exponentially for the remainder of a well life of thirty years. Since most of the production data from these completions is less than six years old, there are very little well decline data available. Historical and industry data indicate that an 8 percent decline is most likely for coalbed gas completions in their later life, and this decline rate was used as a basis for simulating the exponential decline.

The matching curves were used as the basis for generating a vintage well production profile curve by using the production rate-cumulative production and production rate-time equations. Iterative solutions of these equations were made until a unique set of constants A, B, and C for the vintage profile were found. The equations were solved so that the vintage production profile matched as closely as possible the actual annual peak production rates.

The production rate versus cumulative production relationship is:

$$q = \frac{-G_p}{B}(-\ln A + \ln G_p)^2 \quad . \qquad \text{(A14)}$$

The data from the matching curve for a production rate (q) and the corresponding cumulative production (G_p) were used to solve for constants A and B in equation (A14). Iterations of the EXCEL 5.0 SOLVER routine were used to force the curve generated by equation (A14) to track the simulated data curve. The values for constants A and B calculated from equation (A14) were then substituted into equation (A15) and solved for C. The time versus cumulative production relationship is:

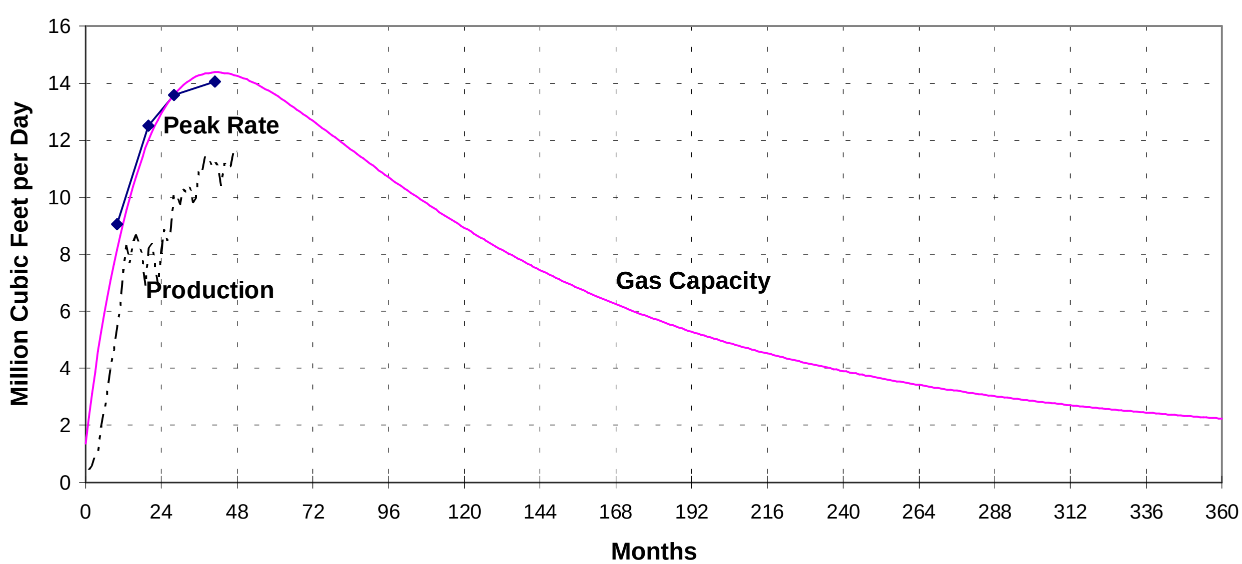
$$C = -t + [B/(\ln A + \ln G_p)] \quad . \qquad \text{(A15)}$$

This solution for C the EXCEL 5.0 SOLVER routine was used again to find the values of A and B using equation (A16). The results from equation (A16) were used to generate a curve similar to the curve generated by equation (A14). Equation (A16) for the rate versus time relationship is:

$$q = A\,[\exp^{B/(C+t)}][-B/(C+t)^2] \quad . \qquad \text{(A16)}$$

Each of the above three equations can be used with a unique set of A, B, and C that will describe coalbed gas well production profile curves that are very close. The EXCEL 5.0 Solver routine was run a final time to find identical values of A and B, using C that would force

Figure A5. New Mexico Coalbed Gas-Well Completion Production and Peak Production Rate



Source: Energy Information Administration, Office of Oil and Gas and Dwight's EnergyData, Inc.

equations (A14) and (A16) generated curves to be as close together as possible. This final value for *A*, *B*, and *C* is then used in the SAS runs for forecasting the coalbed gas capacity. Figure A5 shows the final peak rate curve generated by this technique.

This technique was used to generate production for all the coalbed gas-well for all vintages in all areas.

Gas Demand

The forecast of the gas demand that will be met by domestic production is available on a quarterly basis for the United States for 1996, and 1997 in Table 10 of the *Short-Term Integrated Forecasting System, Fourth Quarter 1996*. {11} The lower 48 States dry gas demand for each quarter was obtained by subtracting Alaska's projected production from the U.S. gas demand (Table A2) and was distributed to each State or area. Since dry gas data are not available on a quarterly basis, but marketed production data are for each State or area (Table A3), the latter are converted to quarterly dry gas (Table A4). For example, in Texas (excluding Gulf of Mexico OCS), the first quarter's marketed production of 1,227,016 million cubic feet (Table A3) is multiplied by .92574 (Table A3) to obtain the dry gas production of 1,135,897 million cubic feet (Table A4). Then the quarterly dry gas production is added for all the areas for each quarter (Table A4). The quarterly dry gas is divided by total dry gas for that quarter and is expressed as a fraction (Table A5). To obtain quarterly gross gas demand for each area (Table A6), the lower-48 gas demand is multiplied by the quarterly dry gas fraction for that State or area and by the ratio of gross gas to dry gas for that State or area. The reason for conversion of demand from dry gas to gross gas basis is that the gas production data from Dwight's are on a gross gas basis.

The quarterly gross gas (gas-well gas plus oil-well gas) is then distributed on a monthly basis for each State or area on its monthly marketed production for 1994. The monthly gross oil-well gas production was determined by multiplying the 1994 annual GOR by the monthly historic oil production for each State or area from 1985 through 1994. Monthly gas production from oil wells was then subtracted from monthly gross gas to get gas production from gas wells.

The monthly gross gas-well gas demand for each State or area was then compared with the monthly gross gas-well gas productive capacity. If the productive capacity was equal to or greater than the demand, the demand was scheduled as production. If the

Table A2. Quarterly Dry Gas Production Forecast, 1996 and 1997 (Trillion Cubic Feet)

Dry Gas Production	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
1996					
U.S. Total Dry Gas Production	4.719	4.772	4.782	4.804	19.077
Alaska Total Dry Gas Production	0.114	0.102	0.097	0.110	0.423
Lower-48 total Dry Gas Production	4.605	4.670	4.685	4.694	18.654
1997					
U.S. Total Dry Gas Production	4.930	4.867	4.914	4.990	19.701
Alaska Total Dry Gas Production	0.114	0.102	0.097	0.110	0.423
Lower-48 total Dry Gas Production	4.816	4.765	4.817	4.880	19.278

Source: Energy Information Administration, Short-Term Integrated Forecasting System, Fourth Quarter 1996.

Table A3. Marketed, Dry, and Gross Gas Production for 1994 (Million Cubic Feet)

State/Area	Marketed Gas Production					Dry and Gross Gas Production and Ratios			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Dry Gas	Dry[a]/ Mkt	Gross Gas	Gross[b]/ Dry
Gulf of Mexico	1,236,573	1,252,443	1,208,530	1,209,808	4,907,354	4,831,500	0.98454	4,942,637	1.02300
Texas[c]	1,227,016	1,261,144	1,296,587	1,260,938	5,045,685	4,670,988	0.92574	5,603,550	1.19965
Louisiana[c]	389,345	380,297	413,940	507,410	1,690,992	1,629,631	0.96371	1,712,116	1.05062
California[d]	78,067	75,286	74,608	81,466	309,427	298,177	0.96364	395,752	1.32724
Kansas	196,535	170,277	157,261	188,658	712,731	665,794	0.93414	714,659	1.07339
New Mexico	380,413	383,038	387,439	406,795	1,557,685	1,471,082	0.94440	1,581,797	1.07526
Oklahoma	490,050	470,992	464,283	509,536	1,934,861	1,833,300	0.94751	1,934,864	1.05540
Southeast									
Alabama[c]	99,851	96,832	95,721	102,368	-	391,450	-	458,360	-
Arkansas	47,074	45,672	45,669	49,257	-	187,120	-	195,413	-
Mississippi	17,020	15,831	16,344	14,253	-	63,023	-	121,802	-
Total Southeast	163,945	158,335	157,734	165,878	645,892	641,593	0.99334	775,575	1.20883
Rocky Mountains									
Colorado	109,873	113,855	113,080	116,401	-	433,595	-	467,030	-
Montana	13,959	11,809	11,069	13,579	-	49,785	-	51,072	-
North Dakota	14,679	15,020	14,161	13,944	-	52,134	-	63,232	-
Utah	66,043	69,012	68,246	67,557	-	257,078	-	347,019	-
Wyoming	172,241	180,645	177,880	165,253	-	662,532	-	1,070,862	-
Total Rocky Mountains	376,795	390,341	384,436	376,734	1,528,306	1,455,124	0.95212	1,999,215	1.37391
18 States	225,351	205,282	211,537	206,947	849,117	827,325	0.97434	862,585	1.04262
Lower-48	4,764,090	4,747,435	4,756,355	4,914,170	19,182,050	18,324,514		20,522,750	

[a]Dry gas divided by marketed gas.

[b]Gross gas divided by dry gas.

[c]Excludes Gulf of Mexico OCS.

[d]California includes Pacific OCS.

-- = Not Applicable.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, corrected data from *Natural Gas Monthly* and *Natural Gas Annual* 1994.

Table A4. Quarterly Dry Gas Production by State and Area for 1994 (Million Cubic Feet)

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Gulf of Mexico	1,217,459	1,233,084	1,189,849	1,191,108	4,831,500
Texas[a]	1,135,897	1,167,490	1,200,301	1,167,300	4,670,988
Louisiana[a]	375,217	366,497	398,919	488,998	1,629,631
California[b]	75,229	72,549	71,895	78,504	298,177
Kansas	183,592	159,063	146,905	176,234	665,794
New Mexico	359,263	361,742	365,898	384,178	1,471,081
Oklahoma	464,327	446,270	439,913	482,790	1,833,300
Southeast	162,854	157,281	156,684	164,774	641,593
Rocky Mountain	358,752	371,650	366,028	358,694	1,455,124
18 States	219,568	200,014	206,108	201,636	827,326
Lower-48 Total	4,552,158	4,535,640	4,542,500	4,694,216	18,324,514

[a]Texas and Louisiana exclude Gulf of Mexico OCS.
[b]California includes Pacific OCS.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Office of Oil and Gas.

Table A5. Quarterly Dry Gas Fraction by State and Area for 1994

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Gulf of Mexico	0.26745	0.27187	0.26194	0.25374
Texas[a]	0.24953	0.25740	0.26424	0.24867
Louisiana[a]	0.08243	0.08080	0.08782	0.10417
California[b]	0.01653	0.01600	0.01583	0.01672
Kansas	0.04033	0.03507	0.03234	0.03754
New Mexico	0.07892	0.07976	0.08055	0.08184
Oklahoma	0.10200	0.09839	0.09684	0.10285
Southeast	0.03578	0.03468	0.03449	0.03510
Rocky Mountain	0.07881	0.08194	0.08058	0.07641
18 States	0.04823	0.04410	0.04537	0.04295
Lower-48 Total	1.00000	1.00000	1.00000	1.00000

[a]Texas and Louisiana exclude Gulf of Mexico OCS.
[b]California includes Pacific OCS.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Office of Oil and Gas.

Table A6. Quarterly Gross Gas Demand by State and Area for 1996 and 1997 (Trillion Cubic Feet)

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			1996		
Gulf of Mexico	1.260	1.299	1.255	1.218	5.033
Texas[a]	1.378	1.442	1.485	1.400	5.706
Louisiana[a]	0.399	0.396	0.432	0.514	1.741
California[b]	0.101	0.099	0.098	0.104	0.403
Kansas	0.199	0.176	0.163	0.189	0.727
New Mexico	0.391	0.400	0.406	0.413	1.610
Oklahoma	0.496	0.485	0.479	0.510	1.969
Southeast	0.199	0.196	0.195	0.199	0.789
Rocky Mountain	0.499	0.526	0.519	0.493	2.036
18 States	0.232	0.215	0.222	0.210	0.878
Lower-48 Total	**5.153**	**5.234**	**5.254**	**5.251**	**20.892**
			1997		
Gulf of Mexico	1.318	1.325	1.291	1.267	5.200
Texas[a]	1.442	1.471	1.527	1.456	5.896
Louisiana[a]	0.417	0.405	0.444	0.534	1.800
California[b]	0.106	0.101	0.101	0.108	0.416
Kansas	0.208	0.179	0.167	0.197	0.752
New Mexico	0.409	0.409	0.417	0.429	1.664
Oklahoma	0.518	0.495	0.492	0.530	2.035
Southeast	0.208	0.200	0.201	0.207	0.816
Rocky Mountain	0.521	0.536	0.533	0.512	2.103
18 States	0.242	0.219	0.228	0.219	0.908
Lower-48 Total	**5.390**	**5.340**	**5.402**	**5.459**	**21.591**

[a]Texas and Louisiana exclude Gulf of Mexico OCS.

[b]California includes Pacific OCS.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Office of Oil and Gas.

productive capacity was less than the demand, then productive capacity was scheduled as production.

For States or areas where monthly gross gas-well gas productive capacity was less than the gross gas-well gas demand, monthly deficits were prorated among the States and areas with surplus gross gas-well gas capacity. This process was repeated until the sum of the monthly scheduled production from all States and areas equaled the monthly lower 48 States gas demand for 1996 and 1997.

The monthly gross gas-well gas productive capacity and oil-well gas production for each State or area were then added to obtain the total monthly gross gas productive capacity and converted to a dry gas basis. The monthly gross gas-well gas scheduled production was added to the oil-well gas production and converted to a dry gas basis.

Drilling and Gas-Well Completions

The number of new well completions coming on stream is based on a projection of the number of rigs running and an estimate of the number of gas-well completions per rig. The history of the number of rigs running by State and area were obtained from Baker Hughes[1] Incorporated, Marketed Research. Gas-well completions[2] were obtained from Dwight's production records.

Forecasts of total drilling rigs were obtained from the *Drilling Rig Model*. This model generates monthly rig counts based on oil and gas revenues which are derived from production and price data appearing in the *Short-Term Energy Outlook (STEO)*.

Data inputs to the *Drilling Rig Model* are provided by 3 sub-models: the *Gas Rig Model*, the *Percentage Gas Rigs Model*, and the *Rig Efficiency Model*. The number of rigs drilling for gas is of particular importance in this study, and the *Percentage Gas Rigs Model*, based on *STEO* oil and gas revenues, provides a forecast of gas rigs. It is also used as input into the *Drilling Rig Model*.

The *Gas Rig Model* provides missing historical gas rig counts for input into the *Percent Gas Rigs Model*. It is based on well completions. The *Rig Efficiency Model* provides for changes in drilling efficiency and is included as an input to the *Drilling Rig Model*. It is based on an index of the inverse of wells drilled per working rig. All of the models are contained in Microsoft Excel spreadsheets. The Excel Solver routine is used to fit and calibrate each model to historical data and minimize the sum of the squared differences in fitting model output to actual historical data.

[1]Baker Hughes Incorporated, Marketed Research.

[2]Model GASCAP94 C110196.

Gas Rig Model

Because a longer historical data series was required than is available for the number of rigs drilling for gas, it was necessary to estimate the missing data. *The Gas Rig Model*, based on gas well completions, was developed to do this. The number of rigs drilling for gas prior to August 1987 was modeled to provide a history for the *Percent Gas Rigs Model*. The *Gas Rig Model* is based on the ratio of successful gas wells to total wells from August 1987 through 1994. The number of active rigs comes from Baker Hughes Incorporated Market Research, and well completion data are obtained from the American Petroleum Institute (API). The Gas Rig Model equation is as follows:

$$GR_i = TR - \left[-8.66688 + 1.383598 + 1.104278 \left(\frac{SOW_i}{STW_i} \right) SRig\,3_i + 8 \right], \tag{A17}$$

where

GR	= gas rigs
TR	= total rigs
SOW	= smoothed oil well completions
STW	= smoothed total well completions
$SRig3$	= smoothed total rigs, 3-month exponential smoothing (exponential smoothing coefficient = 0.5)
i	= current month
-8.66688	=model calibration coefficient
1.383598	= model calibration coefficient
0.139132	= SOW and STW exponential smoothing coefficient
8	= additive constant used to splice the modeled history to the actual history after the fitting and calibration of the model.

The modeled gas rig counts and the post-August 1987 actual gas rig counts are used as input for the *Percentage Gas Rigs Model.*

Percentage Gas Rigs Model

The *Percentage Gas Rigs Model* estimates gas rigs as a percentage of total rigs. Oil and gas incomes (gross revenue) are the input for the model. Production and prices from *STEO* projections are used to determine income. Lower-48 production and prices are used. Prices are converted to 1992 constant dollars and multiplied by production to yield real income. Oil prices were adjusted for the effects of the Windfall Profits Tax (WPT) from March 1980 through December 1985. Oil and gas incomes are exponentially smoothed in the model. A coalbed gas adjustment factor is applied to the gas income term to account for the non-market incentive or subsidy to gas well drilling from Section 29 tax credits. The adjustment is phased in over 2 years beginning in January 1988, held constant through March 1992, increased again through January 1993, and then eliminated by April 1993. The timing of the coalbed gas adjustment coincides with the evolution and impact of the tax credits. The *Percentage Gas Rigs Model* equation is as follows:

$$GRR3_i = 100\ a\ [1 + e\ SOI_i + (d \left(\frac{\sum_{i-12}^{I-23} GI_i}{12} \right) \left(\frac{SGI_i}{SGI_{i-12}} \right) (1 + CB)] \ , \tag{A18}$$

where

$GRR3_i$ = percentage gas rigs (gas rig ratio) with 3-month exponential smoothing (exponential smoothing coefficient = 0.5)

a = 0.630263, model calibration coefficient

e = -0.00387, model calibration coefficient

d = 0.002183, model calibration coefficient

i = current month

SOI = smoothed oil income

GI = gas income

SGI = smoothed gas income

CB = coalbed gas adjustment factor

0.038944 = SOI exponential smoothing coefficient

0.056634 = SGI exponential smoothing coefficient.

The coalbed gas adjustment factor is as follows:

$$CB = 0.052386\ (1 + 0.2\ [X]\ )\ [Y]\ (\ f, g, j\ )\ \ , \tag{A19}$$

where

CB = coalbed gas adjustment factor

0.052386 = model calibration coefficient

0.2 = model calibration coefficient

Y = begins January 1988 at 1/24th and increases by 1/24th each month until equal to 1, then held constant at 1

X = held constant at -5 through March 1992, then increases by 1 each month until equal to 5, then held constant at 5

f = 5.0, model calibration coefficient used only for 1 month, January 1993

g = 2.901857, model calibration coefficient used only for 1 month, February 1993

j = 0.0, model calibration coefficient beginning in March 1993 and held constant thereafter.

The coalbed gas adjustment factor is in effect from January 1988 through February 1993 only.

Rig Efficiency Model

The *Rig Efficiency Model* provides an adjustment of drilling efficiencies as a function of the number of working rigs. It also provides for long term gradual improvements in efficiency due to implementing new and improved technologies. Efficiency is measured as rigs per well. Rigs per well are converted to an index by dividing a running 12-month cumulative rigs per well by an equivalent running 12-month cumulative rigs per well in 1971. The Rig per Well Index is modeled based on exponentially smoothed rig counts and cumulative rig counts. The modeled Rig per Well Index or the *Rig Efficiency Model* is used as input for the *Drilling Rig Model*. The *Rig Efficiency Model* is as follows:

$$RWI_i = 1 + \left[\frac{GRR3_i}{f} \right] c \left(\exp^{-b \left(\frac{CumRig_{i-1}}{1{,}000{,}000} \right)} \right) \left(1 + d \left(\frac{SSRig_{i-1} - SSRig_{i-13}}{LSRig_{i-25}} \right) \right), \tag{A20}$$

where

RWI = rig per well index

$CumRig$ = cumulative rig count beginning January 1968

$SSRig$ = short-time smoothed rig count

$LSRig$ = long-time smoothed rig count

c = 0.471771, model calibration coefficient

b = 0.362558, model calibration coefficient

d = 1.630099, model calibration coefficient

f =31.99129, model calibration coefficient

i = current month

0.02327 = *SSRig* exponential smoothing coefficient

0.03758 = *LSRig* exponential smoothing coefficient

exp = 2.71828, base of the natural logarithm.

Drilling Rig Model

Like the *Percentage Gas Rigs Model*, the *Drilling Rig Model* forecast is based on oil and gas revenue determined from the STEO. Lower-48 prices (in 1992 constant dollars) and production are multiplied to obtain the oil and gas revenues. Oil prices are adjusted for the effects of the WPT. The *Percentage Gas Rigs Model* is also used as input, along with the *Rig Efficiency Model*, a seasonality factor, and an adjustment for the Alternative Minimum Tax (AMT). The AMT adjustment is in effect from January 1987 through November 1993, phased in over 1 year (1987) and phased out over 1 year (1993). The seasonality factor is adjusted depending on the trend direction of the rig count. The model uses oil and gas income terms with both variable and constant exponential smoothing coefficients. The variable smoothing coefficients for both oil and gas income contain a rig count smoothed with a variable coefficient. The *Drilling Rig Model* equation and its component equations are as follows:

$$Rigs_i = b[(1+k)SI_i]^d \, (RWI_i) \, ASn_i \ . \qquad \text{(A21)}$$

where

$Rigs$ = number of active drilling rigs

i = current month

b = 1.263626, model calibration coefficient

k = -0.03024, model calibration coefficient for AMT (used from January 1987 through November 1993 only)

SI = smoothed income term (equation A22)

d = 1.311227, model calibration coefficient

RWI = modeled Rig per Well Index (equation A20)

ASn = adjusted seasonality (equations A26 and A27).

The smoothed income term is as follows:

$$SI_i = SOIV_i + \left(\frac{\left(\frac{GRR3_i}{100} \right)}{\left(\frac{SGIC_i}{SGIC_i + SOIC_i} \right)} \right) SGIV_i \ , \qquad \text{(A22)}$$

where

SI = smoothed income

$SOIV$ = smoothed Oil Income with a variable exponential smoothing coefficient (equation A23)

$GRR3_I$ = modeled Percentage Gas Rigs (equation A18)

$SGIC$ = smoothed gas income with a constant exponential smoothing coefficient

$SOIC$ = smoothed oil income with a constant exponential smoothing coefficient

$SGIV$ = smoothed gas income with a variable exponential smoothing coefficient (equation A24)

i = current month

0.320292 = *SOIC* and *SGIC* constant exponential smoothing coefficient.

The variable exponential smoothing coefficient for *SOIV* is determined by the following equation:

(A23)

$$\alpha_{SOIV_i} = \frac{2}{2 + \left[\left(\frac{SRig12_{i-1}}{SRigV_{i-1}} \right) h \exp^{c\,((SOI6_i - SOI6_{i-2}) - |SOI6_i - SOI6_{i-2}|)} \right]} ,$$

where

α_{SOIV_i} = exponential smoothing coefficient for *SOIV*

$SRig12$ = 12-month exponentially smoothed rig count (exponential smoothing coefficient = 0.1538)

$SRigV$ = smoothed rig count with a variable exponential smoothing coefficient (equation A25)

h = 24, fixed model calibration coefficient

i = current month

c = 0.5, model calibration coefficient

$SOI6$ = 6-month exponentially smoothed oil income (exponential smoothing coefficient = 0.2857)

The variable exponential smoothing coefficient for *SGIV* is determined by the following equation:

(A24)

$$\alpha_{SGIV_i} = \frac{2}{2+\left[\left(\frac{SRig12_{i-1}}{SRigV_{i-1}}\right)^{h} \exp^{f((SGI12_i - SGI12_{i-2}) - |SGI12_i - SGI12_{i-2}|)}\right]},$$

where

α_{SGIV_i} = exponential smoothing coefficient for *SGIV*

$SRig12$ = 12-month exponentially smoothed rig count (exponential smoothing coefficient = 0.1538)

$SRigV$ = smoothed rig count with a variable exponential smoothing coefficient (equation A25)

h = 24, fixed model calibration coefficient

f = 0.400367, model calibration coefficient

$SGI12$ = 12-month exponentially smoothed gas income (exponential smoothing coefficient = 0.1538)

The variable exponential smoothing coefficient for $SRig^{V}$ is determined by the following equation:

(A25)

$$\alpha_{SRigV_i} = \frac{2}{2+\left[\frac{e}{\exp^{0.2((SRig48_i - SRig48_{i-12}) + |SRig48_i - Srig48_{i-12}|)}}\right]},$$

where

α_{SRigV_i} = exponential smoothing coefficient for $SRig^{V}$

SRig48 = 48-month exponentially smoothed rig count (exponential smoothing coefficient = 0.0408)

e = 48, fixed model calibration coefficient

i = current month

Seasonality factors are calculated for each month and calibrated to a preliminary fit of the *Drilling Rig Model* that excluded seasonality. That is, seasonality parameters where added to the *Drilling Rig Model* after fitting and calibrating the model without the seasonality parameters. The model is then run again holding fixed everything other than the seasonality parameters to calibrate only the seasonality coefficients. The seasonality is then held fixed while the nonseasonality parameters were recalibrated in a third fit of the model.

Seasonality is determined by the following equations:

$Sn_{i=1}$ = f for *January*

$Sn_{i=2}$ = $f + \frac{l}{2^{i-1}}$ for *February*

$Sn_{i=3}$ = $f + \frac{l}{2^{i-2}} + \frac{l}{2^{i-1}}$ for *March*

(A26)

$Sn_{i=4}$ = $f + \frac{l}{2^{i-3}} + \frac{l}{2^{i-2}} + \frac{l}{2^{i-1}}$ for *April* ,

$Sn_{i=5,11}$ = $Sn_{i=4} + j(i-4)$ for *May through November*

$Sn_{i=12}$ = $Sn_i = 11 + \frac{i}{3}$ for *December*

where

Sn = the 12 different seasonality factors for January through December

i = 1 through 12 for the corresponding months January through December

f = 1.056388, model calibration coefficient

l = -0.13269, model calibration coefficient

j = 0.014967, model calibration coefficient.

Next, the seasonality is adjusted according to the trend direction as seasonality has less impact when rig counts are increasing than when rig counts are falling. Therefore, adjusted seasonality factors replace the regular seasonality factors as determined by refitting the *Drilling Rig Model* with only the adjusted seasonality parameters allowed to change. Then, the newly calibrated adjusted seasonality factors are fixed while the *Drilling Rig Model* is fit one more time to fine tune the nonseasonal coefficients. The adjusted seasonality equation is as follows:

$$ASn_i = 1 + \frac{(Sn_i - 1)\,(0.5 + 0.5\,\exp^{a})}{0.5 + 0.5\,\exp\left(a\frac{SRig_{\,i-1}}{SRig_{\,i-13}}\right)}\ , \qquad (A27)$$

where

ASn = adjusted seasonality factors

i = current month

Sn = the 12 different seasonality factors for January through December (equation A26)

a = 4.037112, model calibration coefficient

$SRig$ = 24-month exponentially smoothed rig count (exponential smoothing coefficient = 0.08)

The Drilling Rig Model is then run one last time to determine the value for k in equation (A21) (AMT adjustment). The $1 + k$ term is added to the model equation, and all parameters are held constant except k. After the value for the coefficient k is determined, the non-AMT and non-seasonal coefficients are determined by refitting the model again. The projected rig counts are spliced to the historical rig counts, by using a 12-month average ratio of actual-to-predicted rigs calculated three months prior to the last month of actual data. Then the forecast is normalized to the last know data with an additive constant.

Exponential Smoothing

Exponential smoothing is used throughout this modeling process. The following is the basic exponential smoothing equation as applied to income in the Drilling Rig Model.

$$SI_i = I_i\,\alpha + SI_{i-1}\,(1 - \alpha)\ , \qquad (A28)$$

where

SI = smoothed income

I = income

α = exponential smoothing coefficient

i = current month.

Appendix B

Model Abstract

Appendix B

Model Abstract

Name: Wellhead Gas Productive Capacity

Acronym: GASCAP

Description: GASCAP estimates the historical wellhead productive capacity of natural gas for the lower 48 States and projects the productive capacity for 3 years. *The Short-Term Energy Outlook (STEO)* output for *low*, *base*, and *high* cases is used to estimate the number of active rigs and oil and gas well completions. The projected oil production is used to estimate the oil-well gas production (which is assumed to be producing at capacity) by using a constant gas-oil ratio. The gas demand is also taken from *STEO*. The difference between demand and oil-well gas production is assumed to be the gas-well gas demand and the production as long as capacity exceeds demand.

Purpose: GASCAP is used to project the natural gas wellhead productive capacity for the lower 48 States. It also allows quantification of the available productive capacity and the projected capacity under differing future scenarios.

Date of Last Model Update: September 26, 1996

Part of Another Model: No

References to Any Other Models: None

Documentation reference: *Wellhead Gas Productive Capacity Model* (GASCAP) Documentation DOE/EIA-M052, March 1995

Official Model Representatives:

- **Office**: Oil and Gas
- **Division:** Reserves and Natural Gas
- **Branch:** Reserves and Production
- **Model Contacts**: John H. Wood, James N. Hicks, Hafeez Rahman, Velton T. Funk
- **Telephone:** 214-767-2200

Archive Media and Installation Guides: Cartridge tape available from NEIC for GASCAP94 for the report *Natural Gas Productive Capacity for the Lower 48 States 1985 through 1997*, DOE/EIA-0542(96/2).

Energy System Described: GASCAP measures and predicts wellhead natural gas productive capacity.

Coverage:

- **Geographic**: Lower-48 natural gas- producing States
- **Time Unit/Frequency:** Evaluates 13 years of historical data, 1 year of estimated data, and projects productive capacity for 2 years.
- **Products**: Natural gas
- **Economic Sectors**: Not applicable

Modeling Features:

- Model Structure: The model consists of a series of Statistical Analysis System (SAS) procedures utilizing a modified rate of gas production versus cumulative gas production (Rate-cum) equation.
- **Modeling Techniques**: The least squares, nonlinear regression procedure (NLIN) with the Marquardt computational method, was used to fit hyperbolic equations to the data.
- **Special Features**: Estimates conventional and coalbed gas-well gas productive capacity separately.

Non-DOE Input Variables and Sources:

- Dwight's EnergyData Inc, Richardson, TX, Oil and Gas Reports
  - State monthly natural gas production by well
- Baker Hughes Incorporated
  - Number of active rotary rigs and number of active rotary gas rigs
- American Petroleum Institute
  - Drilling statistics monthly tapes

DOE Data Input Variables and Sources:

Natural Gas Annual

- Marketed gas production by State
- Gross gas production by State
- Oil-well gas production by State

Natural Gas Monthly

- Marketed production of natural gas by State

- *Short-Term Energy Outlook*
  - Dry gas production forecast
  - Oil and gas price forecasts

- *Petroleum Supply Annual*
  - Crude oil production

Computing Environment:

Main Frame

- **Hardware**: IBM 3090E Model 400
- **Operating System:** MVS/XA
- **Languages:** FORTRAN / SAS / COBOL
- **Memory requirement:** 1500K
- **Storage requirement:** 1200 tracks of 3380 disk space
- **Estimated run time:** 4 hours CPU time

Personal Computer

- **Hardware**: Compaq Deskpro 386/20
- **Operating System:** MS DOS for Workgroups 3.11
- **Software:** LOTUS 123 / EXCEL / ARBITER / HARVARD GRAPHICS
- **Memory requirement:** 2000K
- **Storage requirement:** 10 Mb hard disk space
- **Estimated run time:** 1 hour

Independent Expert Reviews Conducted:

- Report of findings and recommendations
  Paul R. Carpenter, Ph.D.
  Brattle/IRI, Inc.
  26 June 1995
- Model Quality Audit
  Allied Technology Group, Inc.
  Prepared by QuanTech, Inc.
  29 February 1996

Status of Evaluation Efforts:

- Model Quality Audit report pending.

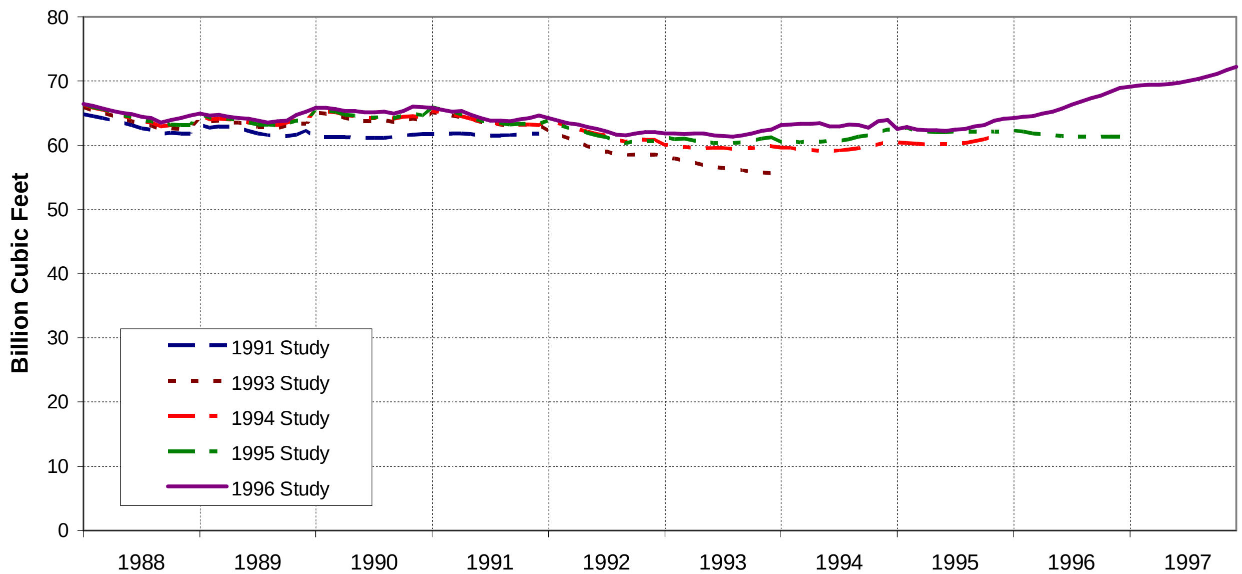
Appendix C

Comparison of Productive Capacity

Comparison of Productive Capacity

Comparisons of base case productive capacities for this and all previous studies were made (Figure C1). In nearly all instances, capacities for the current study were equal to or higher than those in earlier studies.

Figure C1. Comparisons of Base Case Dry Gas Productive Capacity for the 1991, 1993, 1994, 1995, and 1996 Studies



Note: Monthly capacity estimates are for base case.

Sources: 1991 Study: Energy Information Administration. *Natural Gas Productive Capacity for the Lower 48 States 1980 Through 1991*. DOE/EIA-0542(91) (Washington, DC January 24, 1991). 1993 Study: Energy Information Administration. *Natural Gas Productive Capacity for the Lower 48 States 1983 Through 1993*. DOE/EIA-0542(93) (Washington, DC March 10, 1993). 1994 Study: Energy Information Administration. *Natural Gas Productive Capacity for the Lower 48 States 1980 Through 1995*. DOE/EIA-0542(94) (Washington, DC July 14, 1994). 1995 Study: Energy Information Administration. *Natural Gas Productive Capacity for the Lower 48 States 1984 Through 1996*. DOE/EIA-1542(96) (Washington, DC February 9, 1996). 1996 Study: Model GASCAP94 C092696.

Appendix D

Dry Gas-Well Capacity per New Gas-Well Completion

Appendix D

Dry Gas-Well Capacity per New Gas-Well Completion

Dry gas-well gas productive capacity of about one billion cubic feet per day is added per 1,000 new gas-well gas completions. This is the difference between the dry gas-well productive capacity change for the *high* case and the *base* case during 1997 divided by the difference in gas-well completions between the *high* and *base* case during 1997. For productive capacity, the period of change is from December 1996 to December 1997 (Table 2). The well completions for the *base* and *high* cases are those added during 1997 (Figure 9). Capacity is in billion cubic feet per day (Bcf/day) and the number of completions is in thousands.

The calculation follows:

$$\frac{(\textit{Difference in dry gas–well gas capacity change during } 1997 \text{ for } \textit{the high} \text{ and } \textit{base case})}{(\textit{Difference in gas–well completions between the high} \text{ and } \textit{base case during } 1997)}$$

$$= \frac{(69.0\ ^{Bcf}\!/_{day} - 61.3\ ^{Bcf}\!/_{day}) - (64.6\ ^{Bcf}\!/_{day} - 61.1\ ^{Bcf}\!/_{day})}{16.4\ \textit{ThousandCompletions} - 13.3\ \textit{ThousandCompletions})}$$

$$\approx 1\ \frac{^{Bcf}\!/_{day}}{1000\ \textit{Gas–well Completions}}$$

$$\approx 1\ \frac{^{MMcf}\!/_{day}}{\textit{Gas–well Completion}}\ .$$

The estimate of dry gas-well capacity per new gas-well completion depends on three parameters: initial flow rate (qi); ultimate recovery (G_{ul}); and the decline exponent (B) (Table D1). These parameters are an average of the parameters obtained from nonlinear regressions of equation (A6) over the data for each area.

Table D1. Average Initial Flow Rates, Ultimate Recovery, and Decline Exponent on a Conventional Gas-Well Completion Basis for 1991-1993

State/Area	q_i Initial Flow Rate (MMcf/day)	G_{ul} Ultimate Recovery (MMcf)	B Decline Exponent
Gulf of Mexico	7.6	4,881	1.2
Texas	1.0	982	2.2
Louisiana	1.9	1,925	1.9
California (Incl. Pacific OCS)	1.3	990	1.7
Kansas	0.4	845	2.6
New Mexico	0.8	1,765	2.9
Oklahoma	1.0	1,231	2.4
Southeast	1.5	2,918	2.0
Rocky Mountain	0.6	1,032	2.7

Note: Texas and Louisiana exclude Gulf of Mexico OCS; California includes Pacific OCS.
Source: Energy Information Administration, Model GASCAP94 C092696.

Glossary

Glossary

Annual Average-Day Demand: Annual demand divided by the number of days in the year.

Associated Gas: Natural gas, commonly known as gas-cap gas, which overlies and is in contact with crude oil in the reservoir.

Back-pressure: The pressure maintained on equipment or systems through which a fluid flows.

Bcf: Billion cubic feet of gas at a pressure base of 14.73 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit.

Coalbed Gas: Natural gas that is produced from coalbeds. Methane is the principal component. It is commonly referred to as coalbed methane.

Connected Field Capacity: The Natural Gas Supply Association's definition of Connected Field Capacity is "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 that of the individual gas well, 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 natural 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.

Deficit Capacity: The negative difference between gas productive capacity and scheduled gas production.

Deliverability: The volume of natural gas that can be produced from a well, reservoir, or field during a given period of time against a certain wellhead back-pressure under actual reservoir conditions, taking into account restrictions imposed by pipeline capacity, contract, or regulatory bodies.

Demand: U.S. requirement for dry gas from all sources: production, storage withdrawals, supplemental gaseous fuels, and imports.

Dissolved Gas: Natural gas in solution in crude oil in the reservoir.

Dry Gas: Marketed gas less extraction loss.

Extraction Loss: The reduction in volume of natural gas resulting from the removal of natural gas liquid constituents at natural gas processing plants.

Flow String: The string of tubing or casing through which gas or oil flows to the surface.

Gas-Well Gas: Nonassociated or associated gas produced from well completions classified as gas-well completions by a regulatory body.

Gross Gas: Full well stream gas volume, including all natural gas plant liquids and nonhydrocarbon gases, but excluding lease condensate. Also includes amounts delivered as royalty payments or consumed in field operations.

G-10 Rate : Daily gas well production rate calculated as specified on the Railroad Commission of Texas Oil and Gas Division form G-10 and Rule 28.

Lease Condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease or field separation facilities, exclusive of products recovered at natural gas processing plants or facilities.

Marketed Gas: Gross natural gas less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations. Includes all quantities of gas used in field and processing operations.

Mcf: Thousand cubic feet of gas at a pressure base of 14.73 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit.

MMcf: Million cubic feet of gas at a pressure base of 14.73 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit.

Nonassociated Gas: Free natural gas not in contact with crude oil in the reservoir.

OCS: Outer Continental Shelf.

Oil-Well Gas: Natural gas produced from well completions classified as oil-well completions by a regulatory body.

Peak-Day Demand: Highest daily demand that occurred on any one day during the year.

Peak-Month Average-Day Demand: Highest of the 12 monthly demands for the year divided by the number of days in the month.

Peak Shaving: Supplying fuel gas, such as propane, to a distribution system from an auxiliary source during periods of maximum demand, when the primary source is not adequate.

Plant Liquids: Those volumes of natural gas liquids recovered in natural gas processing plants.

Productive Capacity: The volume of natural gas that can be produced from a well, reservoir, or field during a given period of time against a certain wellhead back-pressure under actual reservoir conditions excluding restrictions imposed by pipeline capacity, contract, or regulatory bodies.

Productive Capacity at the Wellhead: The maximum gas production rate that can be sustained for a specific month at the gas-well. It changes over time and cumulatively is a function of gas production and drilling.

Surplus Capacity: The positive difference between gas productive capacity and scheduled gas production.

Tcf: Trillion cubic feet of gas at a pressure base of 14.73 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit.

Vintage Year: The year in which a well first goes on production.

Water-Drive Reservoir: A reservoir in which the rate of water intrusion into the pay substantially equals the volumetric net rate of oil and gas withdrawal.

Well: A hole made by drilling through strata.

Well Completion: A flow string in a well used to conduct fluids to the surface from one reservoir or zone. A producing well may contain one or more well completions.