NATURAL GAS MARKET ASSESSMENT

Producers' Response to Changing Market Conditions

1992-1996

National Energy Board
June 1997

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Acronyms (i)

AEUB	Alberta Energy Utilities Board
ARP	Alberta Reference Price
B.C.	British Columbia
The Board/NEB	The National Energy Board
MBP	Market-Based Procedure
NGMA	Natural Gas Market Assessment
R/P	Reserves to production ratio
U.S.	United States
WCSB	Western Canada Sedimentary Basin

Conversion Factors (ii)

Metric to Imperial

Metric	**Imperial Equivalent Units**
1 cubic metre of natural gas (101.325 kilopascals and 15°C)	= 35.301 01 cubic feet (14.73 psia and 60°F)
1 gigajoule (GJ)	= approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf

Units (iii)

Prefix	**Multiple**	**Symbol**
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

Mcf	=Thousand cubic feet
Bcf	=Billion cubic feet
Tcf	=Trillion cubic feet
Bcm	=Billion cubic metres
Mmcf/d	=Million cubic feet per day
Tcf/yr	=Trillion cubic feet per year
GJ	=Gigajoule (10^9 joules)

F O R E W O R D

The National Energy Board ("the Board" or "NEB") continually monitors the overall energy situation in Canada, considering both long-term and short-term developments in supply and demand.

An analysis of the long-term outlook for supply and demand of all energy commodities is published periodically in the Board's *Canadian Energy - Supply and Demand* reports[1]. With respect to natural gas, the reports provide long-term outlooks for natural gas supply and demand, including perspectives on reserves, productive capacity, prices, demand and interfuel substitution, in the overall framework of Canadian energy commodities.

As part of the monitoring function, the Board provides information regarding changes in market conditions and overall natural gas supply and demand. Specific developments in the natural gas market are monitored and reviewed periodically in the Board's Natural Gas Market Assessment ("NGMA") reports. NGMAs are focused on current issues, particularly those related to the functioning of the market and the characteristics of the resource base.

The broad objective of this NGMA report is to advance the understanding of natural gas supply issues by examining upstream gas-industry activity and the results of this activity, for the period 1992 to 1996. During this time, a record number of gas wells were drilled, a large number of pools were connected for production and the pattern of exploration and development changed significantly. The dynamic response by the upstream gas industry to price and market signals demonstrates its ability to provide adequate gas supplies in times of rapidly increasing demand. Although this study is focused on one wave of activity which was triggered by particular market conditions, it is possible to make some generalizations regarding the technical characteristics of gas supply. In this way, the study improves both our understanding of the response of the industry to market circumstances and of Canadian gas resources in general. It also provides some insight into how the industry might respond to changing market conditions in the future.

[1] *Canadian Energy Supply and Demand 1993-2010* , published December 1994, is the most recent of these reports.

This report reviews the natural gas producing sector's response to changing market conditions over the period 1992 to 1996, with particular attention directed to the relationship between gas prices and industry activity levels.

The early part of this period was characterized by increasing demand and rising prices leading to a situation where supply and demand were in near balance, and providing the first test of productive capacity that the producing sector had faced since deregulation. In response to increasing prices, additional productive capacity was quickly built-up, to the extent that a surplus of productive capacity again developed.

The later part of this period featured continued growth in demand, but with falling gas prices and some reduction in producers' activity levels. Activity, although reduced, remained at higher levels than might be expected in a lower price environment due to producers' need to maintain production, reserves levels, market share and cash flow.

The deregulation of the North American gas market began in 1985 with the Western Accord and the Agreement on Natural Gas Markets and Prices, which featured price deregulation and the establishment of open access on pipeline transmission systems. This resulted in a rapidly evolving, increasingly competitive market place, that is continuing to change. In order to provide a background for the discussion of producers' response to the various market signals, the study begins with a review of changing market conditions. The study then focuses on three major aspects of the producers' response to changing market conditions. These are:

- the levels and characteristics of gas-directed activity and producers' responsiveness to market signals;
- changes in the underlying characteristics of gas supply, such as well productivity and production decline profiles; and,
- the effectiveness of drilling activity in finding new reserves and adding productive capacity.

At the onset of deregulation, a condition of excess productive capacity existed in the Canadian gas market, reflecting provincial and national regulatory requirements and industry contracting practices. Following deregulation, gas wellhead prices fell by 40 percent over the period 1985 to 1987. In the sustained lower price environment that existed after 1987, the producing sector was forced to become more competitive. Companies responded by reducing costs and increasing efficiencies in all segments of their operations. Perhaps the most visible examples are the numerous instances of corporate re-structuring, involving mergers and take-overs, as well as downsizing. The rationalization and optimization of property holdings also played a prominent role. The adoption of innovative technology in the many sectors of the industry has generally resulted in increased efficiencies and reduced costs. Additional efficiencies were achieved through initiatives in supply management, as evidenced by the move to lower reserves to production ratios and the development of significant additional storage, particularly in the upstream sector. Through the realization of greater efficiencies and reduced costs, in combination with the aggressive expansion of export sales, the producing sector was able to maintain its viability in spite of lower prices and returns.

The lower gas prices of the late 1980s tempered the pace at which additional productive capacity was developed, while both domestic and export demand increased substantially. Over the period 1987 to 1991, domestic demand increased by 12 percent, exports grew by 71 percent, and production was up 34 percent. This led to a condition in which deliverability and demand within the WCSB were in closer balance by 1992, setting the stage for a new price and activity cycle over the period mid-1992 to mid-1995.

In response to increasing prices and rapidly rising demand in 1993 and 1994, producers undertook an unprecedented wave of upstream industry activity, characterized by aggressive land acquisition, high levels of geophysical activity, record-breaking levels of drilling, and an accelerated pace of well connection. The consequence of this increased activity was a build-up in productive capacity, which exceeded pipeline take-away capacity and re-created the surplus situation of the 1980s.

The additional storage capacity that had been put in place to better manage peaks in demand, combined with the mild winter of 1994/1995, resulted in a decreased call on production to replenish storage in the following summer. Subsequently, the Alberta average wellhead gas price fell from a peak of $2.10/GJ in April 1994 to $1.05/GJ in August 1995. As a result of declining prices and excess supply, the level of gas well drilling fell by 33 percent in 1995.

Over the winter months of 1995/1996, gas prices recovered to the $1.60/GJ level, due in large part to the cold weather in major consuming areas. Although prices subsided to the $1.40/GJ level by mid-summer 1996, they recovered in the fourth quarter, primarily due to increased U.S. demand. With respect to the level of drilling activity, the data indicate that the number of gas wells drilled in 1996 will be similar to 1995 levels.

A number of observations can be made with respect to upstream activity over the study period. For instance, in 1993-1994, with demand and prices increasing, industry responded by quickly developing additional productive capacity. This additional capacity was predominately sourced from the low cost, shallow, sweet gas areas of central, southeastern and eastern Alberta, and south-western Saskatchewan. The level and regional distribution of land acquisition, geophysical crew count, drilling, and well connection, all indicated concentration on these shallow gas areas. The practice of relying heavily on the low-cost shallow gas areas to quickly add productive capacity demonstrates the industry's tendency towards a "just-in-time" approach to inventorying gas supply. There was correspondingly less emphasis on the regions where the gas reservoirs tend to be deeper, more sour gas prone, and more expensive to develop. By 1995, with falling prices and an excess of supply over demand, the level of drilling activity decreased, with less emphasis on quickly developing supply capability and more emphasis directed to drilling in deeper horizons; this situation persisted in 1996.

Although the well count declined from the record levels of 1994, the drilling effort, on average, over the 1993 to 1996 period still represents a significantly higher level of drilling compared to the 1991 to 1992 period. The observation that a much higher level of activity was maintained in 1995 compared to 1992 (although these two years featured similar lows in prices), suggests that producers were motivated to maintain the pace of drilling activity by factors other than market price alone.

In part, this higher level of activity was due to changes in certain underlying supply characteristics which have had a direct bearing on the drilling and well connection activity required to maintain production levels. The majority of producing gas wells in the WCSB are in the decline phase of their producing life, and producers must bring on additional wells in order to maintain deliverability. Thus, the production decline characteristics of gas wells have a direct bearing on activity levels. A review of the decline profiles of Alberta gas wells showed that average decline rates are increasing over time. The overall average production decline rate for Alberta gas production was 18 percent per year at the end of 1995, compared to 9 percent in 1984.

Another supply characteristic that is changing is the average initial producing rate. An analysis of these rates for gas wells in Alberta indicated that the average first-year production rate decreased by 10 percent over the period 1992 to 1996. This reflects the regional distribution of drilling activity as well as the distribution of development versus exploratory wells over this period.

Because of decreasing average initial well productivity and higher well decline rates, as time passes more wells have to be drilled to maintain any given aggregate production level. This means that a progressively higher base level of activity has to be sustained to meet the current demand for gas.

The rate at which wells become depleted and are removed from production is also an important component of the overall production decline rate. The impact of this component increases over time, because, as the total operated-well count increases, so too does the number of wells that reach full depletion and are removed from production.

In Alberta, to replace production loss due to decline, and to account for an estimated 2 to 3 percent annual increase in demand, approximately 3 400 to 3 800 wells would have to be drilled and connected each year. For comparison, this is slightly more than the total of 3 275 wells which were connected for production in 1996. This estimate of the required drilling levels is based on the 1995 average initial production rates and decline profiles determined for each of 13 areas in Alberta. Further, the estimate pertains only to a near-term, 2 to 3 year period, and refelects the regional distribution of gas-well drilling over the study period. Although there was some evidence of a shift in the drilling effort to regions and zones of higher well productivity in 1995 and 1996, a more pronounced shift would likely be necessary to significantly reduce the level of required drilling in the near term.

As an alternative to drilling new wells, the inventory of nearly 14 000 unconnected gas wells that currently exist in the WCSB provides another potential source of supply. In recent years, however, the industry has relied heavily on the drilling and connection of new wells to add to supply capability, with less reliance on wells from the older, unconnected inventory. Over the four-year period to the end of 1995, only 35 percent of newly connected wells came from the pre-1992 inventory. In addition, approximately 36 percent of 1995 gas production came from wells less than 3 years old; that is, they were put on production sometime after 1992. Furthermore, in 1995, 39 percent of new well connections were in pools more than 20 years old, compared to 61 percent in 1985. Although still important, the older, larger pools are now playing a less dominant supply role.

One of the problems associated with estimating the volumes of gas reserves found by drilling is the two to three year time lag for newly-discovered reserves to be fully assessed and reported in the public databases. In order to better understand the impact of current drilling, a methodology was developed to provide an early estimate of reserves found. This is based on a statistical analysis of historical gas reserves and drilling data. Taking into account the number of successful gas wells drilled, their location and the geological formations encountered, reserves discovered were estimated at 73.5, 108.0 and 105.3 billion cubic metres (2.6, 3.8 and 3.7 Tcf) for 1994, 1995 and 1996, respectively.

In a similar fashion, a statistical method for the estimation of the productive capacity added by recent drilling and well connection was also developed. This method is based on an analysis of average initial producing rates and average production decline profiles for each of 13 areas in Alberta. Taking into account the number and the distribution of successful gas wells drilled over the period 1992 to 1996, the potential productive capacity added was estimated at 6.8, 18.9, 30.2, 29.7 and 34.9 billion cubic metres per year (0.2, 0.7, 1.1, 1.1 and 1.2 Tcf/yr) for each of the years 1992, 1993, 1994, 1995 and 1996, respectively.

The impact of wells actually connected for production over the study period, including wells from the pre-1992 inventory, was also estimated. The carry-forward effect and production decline are considered in this determination. The cumulative contribution to productive capacity for each year was determined to be 4.5, 20.9, 41.9, 59.3 and 65.2 billion cubic metres per year (0.2, 0.7, 1.4, 2.0 and 2.3 Tcf/yr) for each of the years 1992, 1993, 1994, 1995 and 1996, respectively.

A certain portion of the total potential productive capacity added was not utilized, as a number of wells were not connected for production. On an annual basis, the magnitude of this estimated undeveloped capacity, derived from wells drilled over the study period, peaked in 1994 at 10.3 billion cubic metres per year (0.4 Tcf/yr) and decreased to 8.5 billion cubic metres per year (0.3 Tcf/yr) by 1996.

In conclusion, the study found that over the period 1992 to 1996, changing market conditions presented the producing sector with important challenges. The key features of these changing conditions and producers' response are:

- Producers became more efficient in response to increased competition and volatile, generally lower gas prices, by:
  - reducing costs through corporate restructuring, downsizing, optimizing property holdings, reducing finding and development costs, and aggressively using new technology; and,
  - focusing more on the short-term, as evidenced by the move to a "just in time" approach to managing gas reserves inventories.
- The indicators of activity levels used in the study (land sales, geophysics, drilling, well licensing) displayed a sharp, positive response to rising prices and a corresponding negative response to falling prices, with a certain time lag between the price signal and the response.
- The underlying characteristics of supply appear to have changed. Producers faced steepening production declines, decreasing average initial productivity per well and increasing numbers of well depletions.
- After 1994, a higher base or "required" level of activity was apparent. In 1995, there were 40 percent more gas wells drilled than in 1992, even though prices in those years were similar. This higher base level of drilling is thought to be due primarily to the changes in supply characteristics, and the corresponding need to put increasingly more wells on production. The need to replace reserves and the need to maintain cash flow are important considerations as well.
- Gas drilling activity was focused primarily on development, and on the shallow gas regions in 1993 and 1994. In 1995, with the need to add additional deliverability not as urgent, drilling activity decreased, with a greater emphasis on development and exploration drilling in deeper horizons.

- There is an increasing reliance on the drilling and connection of new wells, with less reliance on the inventory of older wells.
- The overall decline rate of Alberta's producing gas wells is increasing each passing year and stood at 18 per cent in 1995. This trend to steeper declines will likely continue, at least over the next 2 to 3 year period. As a result, an increasing volume of additional deliverability will have to be connected, primarily through new wells, to account for this production decline, plus any increase in demand. It is estimated that some 3 500 to 4 000 wells will have to be drilled and connected annually in the WCSB, over the 1997 to 1998 period, to meet this requirement. This assumes only modest increases in demand, similar to the three percent level of 1996, and that the regional pattern of drilling and development will be similar to that of the study period.
- The producing sectors' response to the challenges it faced demonstrates that it has evolved into an efficient and highly competitive component of the gas marketplace, able to quickly respond to changing market conditions. It can be characterized as a healthy, robust sector of the industry, that is actively exploring and developing Canada's natural gas resources. The sector has clearly demonstrated its ability to ensure adequate supplies at fair market prices during periods of rapidly increasing demand.

INTRODUCTION

This study examines the response of natural gas producers in the Western Canada Sedimentary Basin ("WCSB") to the changing gas market conditions over the period 1992 to 1996.

The background to the study is the economic and policy environment that followed deregulation in 1985 with the Western Accord and the Agreement on Natural Gas Markets and Prices.[2] The gas market has undergone a rapid evolution since deregulation, within an environment of generally lower gas prices and increased competition among producers and in end-use markets. This increased competition has resulted in a more efficient industry, as companies have sought to reduce costs in all facets of their operations. The more competitive environment and the focus on cost reduction has resulted in a greater emphasis on near-term objectives, with the least-cost gas supply regions heavily targeted to meet increased demand.

To provide a background for the discussion of supply, the study starts with an overview of the evolving market conditions that followed the initial steps toward deregulation. It then provides a regional breakdown of how producers responded to changing market conditions, illustrated by trends in gas-related activity levels for nine regions within the WCSB. Finally, to provide a more immediate understanding of the outcome of this activity, an initial estimate of the impact of recent drilling on reserves discoveries and productive capacity is presented.

The study focuses on several aspects of the producers' response to evolving market conditions. First, the levels of gas-directed activity within the producing sector over the 1992 to 1996 period are examined, including the relationship between price and activity levels, through the analysis of data on:

- the lag time between market signals and producers' response;
- acquisition of exploration rights and trends in geophysical exploration;
- the level of drilling activity and the balance between exploration and development effort; and,
- the pace of connecting wells for production.

Second, the study provides an examination of underlying supply characteristics which have a bearing on producers' efforts to maintain and expand gas supply, through an analysis of:

- the vintage and productivity of newly-connected wells;
- the trends in production rates; and,
- the trends in well decline rates.

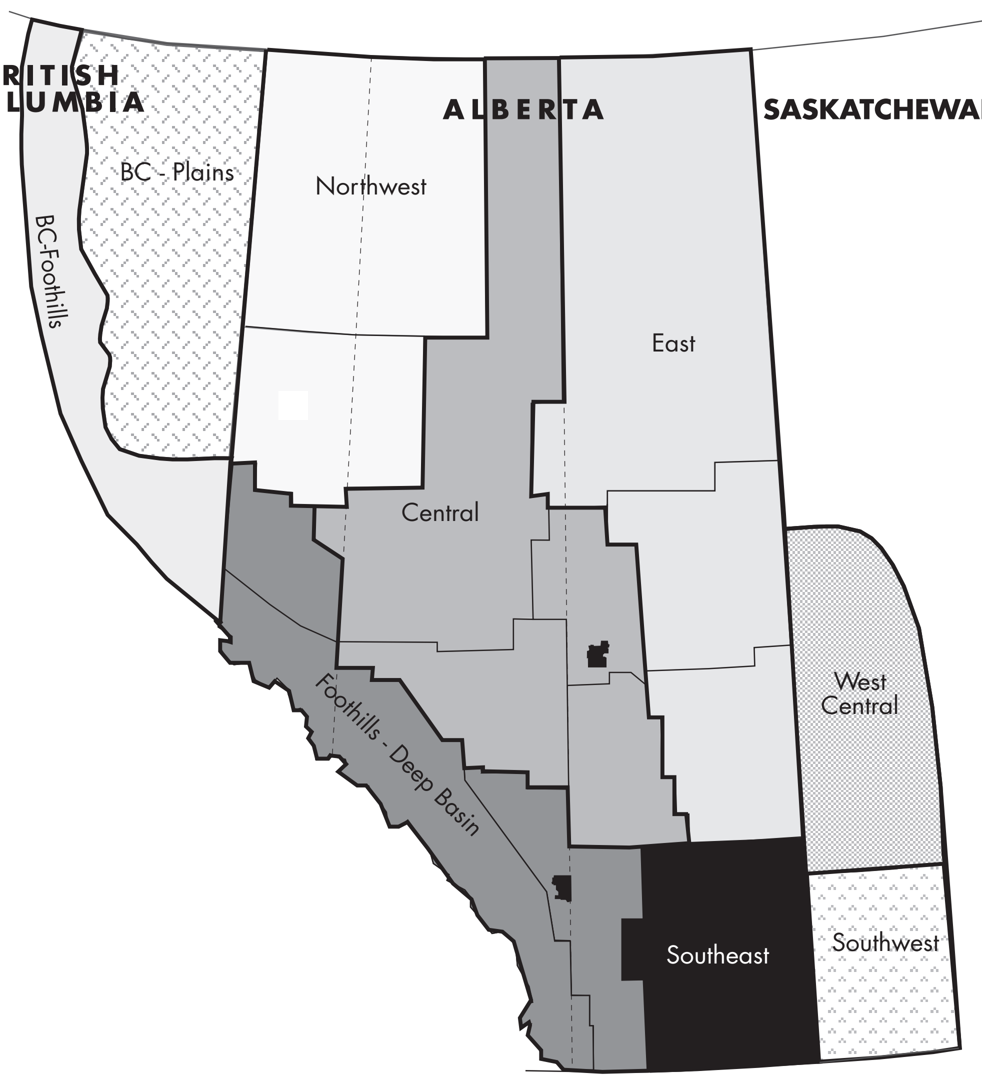
[2] A discussion of the features of deregulation can be found in the NEB report: *Natural Gas Market Assessment*, October 1988.

Third, producers' success at finding new reserves and developing additional productive capacity has a direct bearing on gas supply trends. To provide a measure of the results of recent drilling, methods were developed to yield more timely estimates of gas reserves additions and productive capacity based on the latest available drilling statistics. The study presents a description of these methods and the results obtained.

To properly account for regional details across the basin and across geological zones, a regional distribution of these trends is also presented, for nine regions within the WCSB (Figure 1.1). While each of the three major producing provinces of B.C., Alberta and Saskatchewan were included in the various types of assessments that were carried out, in the interest of brevity, certain points are illustrated with data for Alberta only.[3]

FIGURE 1.1

Western Canada Gas Regions



[3] In 1995, Alberta contributed 4.4 Tcf of the 5.3 Tcf of marketable natural gas produced in the WCSB.

REVIEW OF MARKET CONDITIONS

This chapter provides a brief description of the evolving market conditions that followed measures taken to deregulate markets and prices in Canada and in the United States. More specifically, it addresses those market factors that were important in the shaping of producers' response over the period 1992 to 1996.

2.1 Background: 1985-1991

Prior to 1985, gas producers in the WCSB operated in a highly regulated environment. Prices were regulated by government at what had become high levels by 1985, and there were regulatory requirements for maintaining a large inventory of gas reserves, to ensure that exports from Canada were surplus to reasonably foreseeable domestic requirements. At the same time, there were similar provincial regulations in place. In addition, gas was generally sold under long-term contracts, which commonly included take-or-pay provisions. The combination of high prices and guaranteed take clauses in gas sales contracts provided a powerful incentive for producers to explore for and develop new gas supplies. While supply increased, high prices discouraged demand, resulting in a major excess of productive capacity over demand at the time of deregulation.

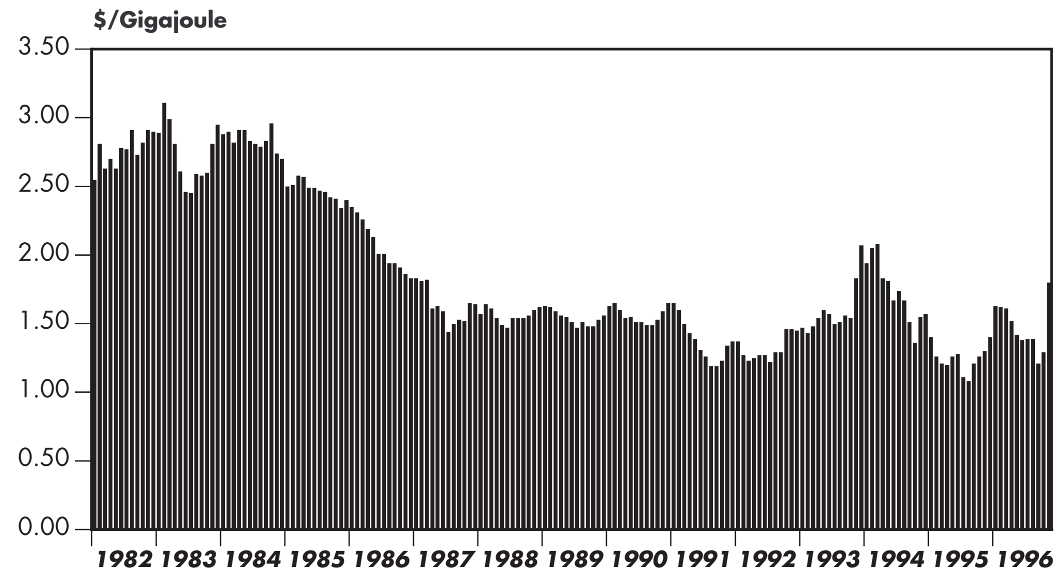
Among other things, deregulation allowed producers to sell gas directly to end-users at freely-negotiated prices, and also provided producers with open access to gas transportation services. Further, in 1987, the National Energy Board (the "Board" or "NEB") adopted the Market-Based Procedure (MBP) for assessing applications for long-term gas export licences. The MBP effectively removed the need for industry to carry large reserves inventories to support exports.[4]

Deregulation, primarily the deregulation of gas prices, in conjunction with an excess of productive capacity over demand in the WCSB and sharply lower world oil prices, contributed in large part to a dramatic decline in wellhead prices for gas. From a pre-deregulation price of $2.80/GJ in 1984, prices fell by 46 percent to $1.50/GJ by mid-1987 (Figure 2.1).

[4] A more complete discussion of regulatory changes can be found in the Board's 1996 NGMA Report: *Canadian Natural Gas, Ten Years after Deregulation*.

FIGURE 2.1

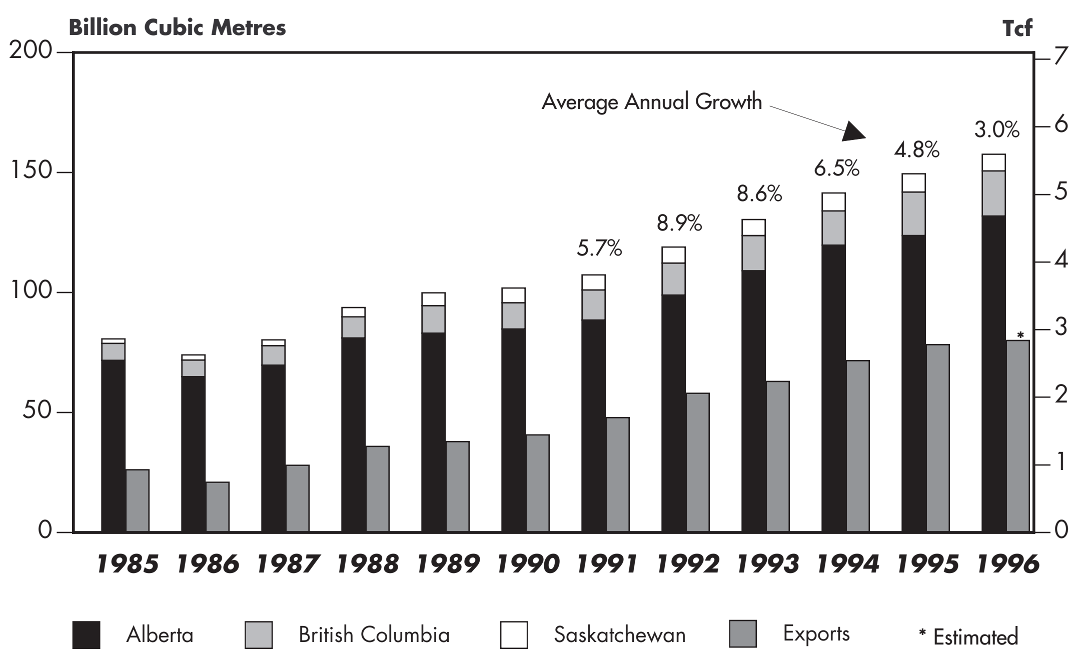
Historical Natural Gas Prices - Alberta (1982-1996 by month)



Sources: APMC Annual Reports, Canadian Natural Gas Focus, Alberta Department of Energy

FIGURE 2.2

Western Canada Historical Marketable Gas Production



During the period 1987-1991, continued lower gas prices, the expansion of pipeline systems, and regulatory developments in Canada and the U.S., resulted in a pronounced increase in the demand for Canadian gas (Figure 2.2). At the same time, the low gas prices tempered the pace of developing additional supply capability, with the result that the excess of supply over demand was substantially reduced over this period.

The total effect of deregulation was to create a much more competitive and integrated North American gas market with generally lower and more volatile gas prices. In reaction to this more competitive environment, producers were compelled to cut costs in an effort to maintain profitability and market share.

One highly visible response was cost-cutting through business redesign. For many companies, this included downsizing, with the resultant layoffs of office and field staff. In fact, many of the industry majors have undergone several rounds of layoffs. Another response was the optimization of property holdings to reduce overall costs through the elimination of duplicated functions and infrastructure. In addition to the rationalization of assets through acquisition, sale and swap arrangements, there have been many mergers and buyouts, that also contributed to optimization of assets.

The exploitation of new technology, much of it related to the rapid advancement of computer and electronics technology, has also led to greater efficiency in almost all facets of the industry. For example, finding costs have been reduced through advances in the acquisition, processing, and interpretation of seismic and other types of geophysical and remote sensing data. Enhanced drilling techniques, advanced drill bit design, the use of coiled tubing, and under-balanced drilling have all led to lower costs for exploration and development drilling.

FIGURE 2.3

Working Gas Storage - Maximum Capacity

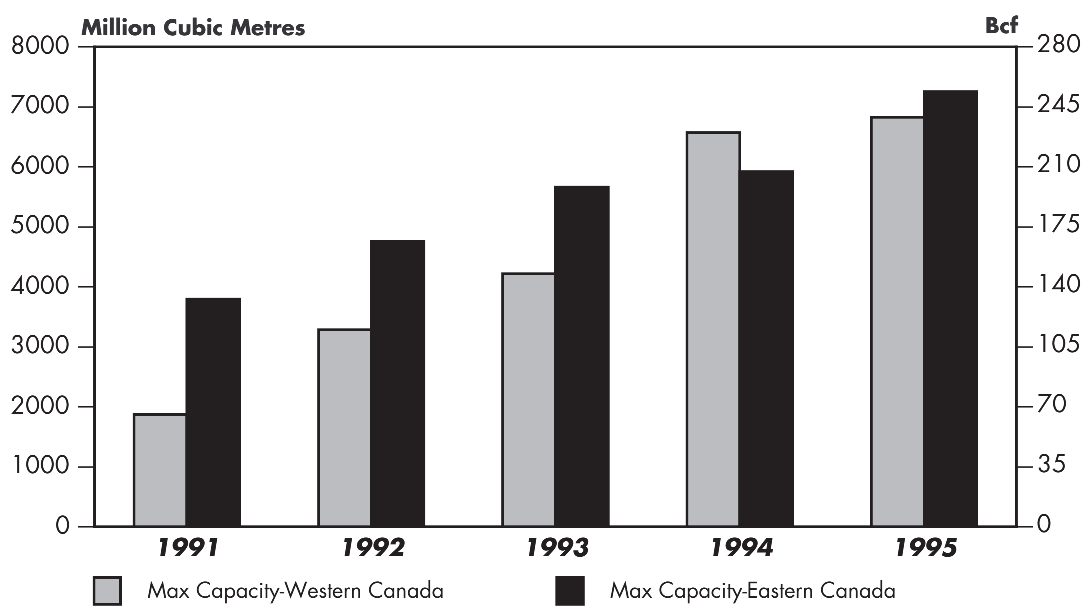
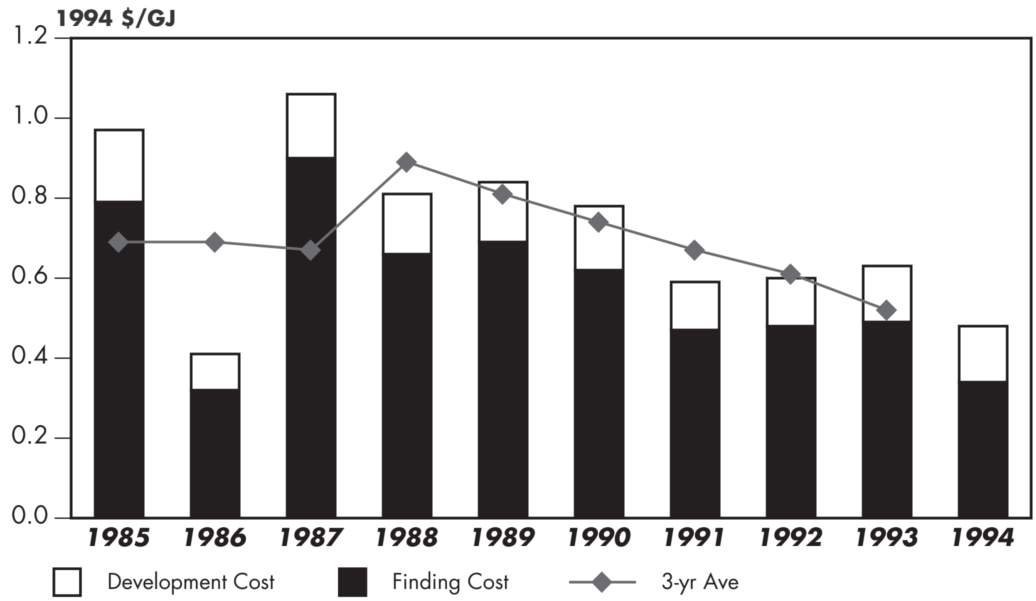


FIGURE 2.4

Gas Replacement Costs - Alberta



Source: Calgary Energy Consultants Ltd.

Because of the need to control all costs, including transportation costs, gas storage systems in Canada were greatly expanded to better manage peaks in demand (Figure 2.3). In addition, extensive additional transportation capacity was put in place through major expansions on existing pipeline systems[5].

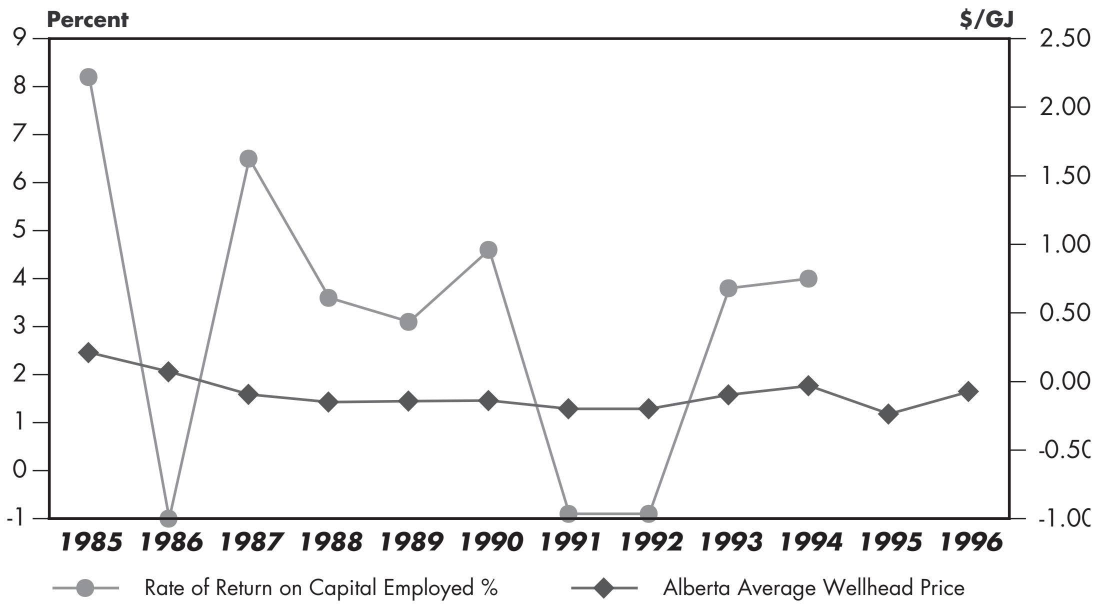
The advent of electronic bulletin boards for the trading of gas futures contracts, for pipeline space allocation, and for the nomination of storage, have all enhanced efficiency by providing additional flexibility to producers. They also allow for the rapid dissemination of information regarding gas transportation and marketing opportunities.

The overall effect of the efficiencies gained, as discussed above, is evident in the downward trend in Alberta's gas replacement costs (Figure 2.4). However, in spite of producers' efforts to adjust to low prices, the rate of return on capital in the upstream petroleum sector declined over the 1987 to 1991 period (Figure 2.5).

[5] As documented in the 1996 NGMA Report: *Canadian Natural Gas, Ten Years after Deregulation.*

FIGURE 2.5

Rate of Return on Capital vs Gas Price - Western Canada



Source: Petroleum Monitoring Agency, rate of return data unavailable after 1994.

2.2 Market Conditions 1992-1996

Deregulation, cost cutting, and the need to enhance profitability, created an upstream sector which was prepared to quickly respond to changing market signals. This became very evident in the volatile period after 1991.

Over the first half of 1991, the Alberta Natural Gas Reference Price[6] ("ARP") declined sharply to about $1.20/GJ, then rebounded somewhat over the winter of 1991/92, before again falling to the $1.20 level. Prices were depressed over this period by generally warmer weather and the effect of the 1991-1992 economic recession on demand. Given these low prices, there was little or no incentive for producers to expand deliverability and the number of gas wells drilled in 1992 dipped to a twenty-year low. Subsequently, domestic, and particularly export, demand grew rapidly in response to low prices.

By 1992, deliverability and demand within the WCSB were in relatively close balance[7], setting the stage for a new price cycle that began in mid-1992.

[6] The Alberta Natural Gas Reference Price ("ARP") is defined as the weighted average field price for Alberta gas delivered for consumption in or exported from Alberta, adjusted for transportation costs, marketing allowances, and adjusted for pipeline fuel/loss. The ARP was chosen because it most accurately represents the price paid to producers at the fieldgate.

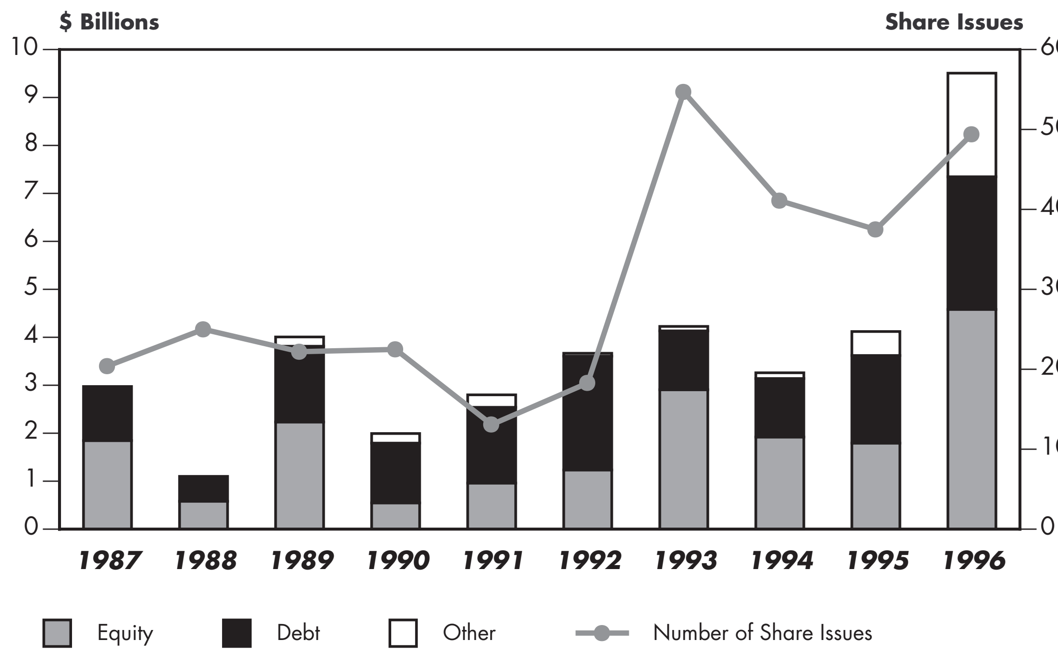
[7] As documented in the 1993 NGMA Report: *Natural Gas Supply-Western Canada: Recent Developments (1982-1992), Short Term Deliverability Outlook (1993-1996)*.

From 1992 to 1993, several market factors combined to initiate a period of increased upstream activity. The relatively cold winter of 1992/1993 resulted in a notable increase in demand. Prices started to recover in mid-1992, reaching a peak of $2.10/GJ during the cold winter of 1993/1994. The level of industry financing, rate of return on capital, and share issues all increased, coincident with rising demand (Figures 2.5, 2.6).

By mid-1994 to early 1995 market conditions had changed once again, and a marked decline in activity occurred.. The winter of 1994/95 was quite mild, reducing the call on production to replenish storage. As well, in spite of the expansion of pipeline capacity, the vigorous response in the development of productive capacity resulted in a renewed surplus with market opportunities constrained by pipeline takeaway capacity.[8] Gas prices fell from a level of $2.10/GJ in April 1994 to about $1.05/GJ in August of 1995. Some producers responded to these low prices by taking a portion of their production off the market for a period of time. Over the winter months of 1995/1996, the ARP recovered to the $1.60/GJ level due in large part to a relatively long period of very cold temperatures.

F I G U R E 2 . 6

Canadian Oil Industry Treasury Financing Transactions



Source: Sayer Securities Limited

Note: "Other" category includes royalty trust units, limited partnership units and other types of non-traditional investments of a securities nature.

[8] Canadian Energy Research Institute, 1995: *Survey of Canadian Natural Gas Deliverability, Production, Reserves and Investment.*

2.3 Producers' Response 1992-1996

Current and anticipated market prices, while the most important and direct determinants, are not the only factors bearing on activity levels. The pace of demand growth and the availability of equity financing are also important. Other considerations facing producers include: contractual supply commitments; land obligations which call for exploration expenditures within a specified time frame; obligations to investors; the need to maintain cash flow; and on the technical side, the need to replace reserves and maintain levels of productive capacity.

During the upswing portion of the gas price cycle, industry responded with an unprecedented wave of exploration and development activity. This was characterized by aggressive land acquisition, high levels of geophysical activity, record-breaking levels of drilling and an accelerated pace of gas well connection. Over the 1992 to 1996 period, marketable gas production rose by an annual average of eight percent reflecting annual growth in exports of 11 percent and in domestic sales of six percent (Figure 2.2).

As prices declined to lower levels in the second half of the cycle, activity fell off somewhat, but settled at levels which are higher than those observed during previous periods of comparable prices. This higher base level of activity reflected the response of producers to changing market conditions and characteristics of supply within the WCSB. Chapter 3 and Chapter 4 provide a more detailed review of the response of producers to market signals over the study period.

PRODUCERS' RESPONSE TO CHANGING MARKET CONDITIONS/SHIFTING PATTERNS OF GAS SUPPLY

An examination of various aspects of gas-directed activity in the period 1992 to 1996 was conducted to understand producers' response to changing market conditions and to identify shifting patterns and characteristics of gas supply within the WCSB. This examination included the following items:

- the lag time between market signal and industry response;
- trends in gas-directed land acquisition;
- the levels and trends in gas-directed geophysical activity;
- the levels and trends in gas-directed exploration and development drilling; and,
- the overall trend to higher activity levels.

The regional distribution of these aspects is also provided for nine gas regions within the WCSB. This breakdown captures important regional differences and identifies important details that would be masked if the data were aggregated by province or for the whole of the WCSB.

3.1 Market Signals, Industry Response and Lag Time

In this section we examine the "cause and effect" relationship between prices and activity levels. Producers' responses track the swings in market prices[9], delayed somewhat in time depending on operational requirements and seasonal effects.

Figure 3.1 shows the twelve-month moving average of activity levels for land sales, geophysics, drilling and well licensing, all plotted against the gas price. In each case, there are similarities in the price versus activity relationship.

The low levels of activity in 1991 and 1992 are coincident with low gas prices in those years. With rising prices in 1993 and 1994, activity increased substantially to peak levels in the second half of 1994. Another similarity is the lag time between the peaks and troughs in prices in comparison with the corresponding peaks and troughs in activity levels. For example, while gas prices peaked in the first quarter of 1994, most activity parameters peaked in the fourth quarter of 1994.

[9] Producers may be more influenced by their expectations of future prices rather than actual prices; however, this is difficult to assess analytically.

REGIONAL SETTING

THE study encompasses the major natural gas producing regions of the WCSB within the provinces of British Columbia, Alberta and Saskatchewan. Within these provinces, 17 individual areas and seven geological zones were defined. These areas are shown on Figure A1-1, Appendix I, numbered 1 through 17, and the geological formation groups used are also shown in Figure A1-1. Although most elements of the study were examined for all 17 areas and for seven geological zones, for purposes of presentation the areas were recombined into nine NEB regions - two in British Columbia, five in Alberta and two in Saskatchewan. The nine NEB regions are named as shown in Figure 1.1. In most cases the geological formation groups are presented as one aggregate group within each gas region.

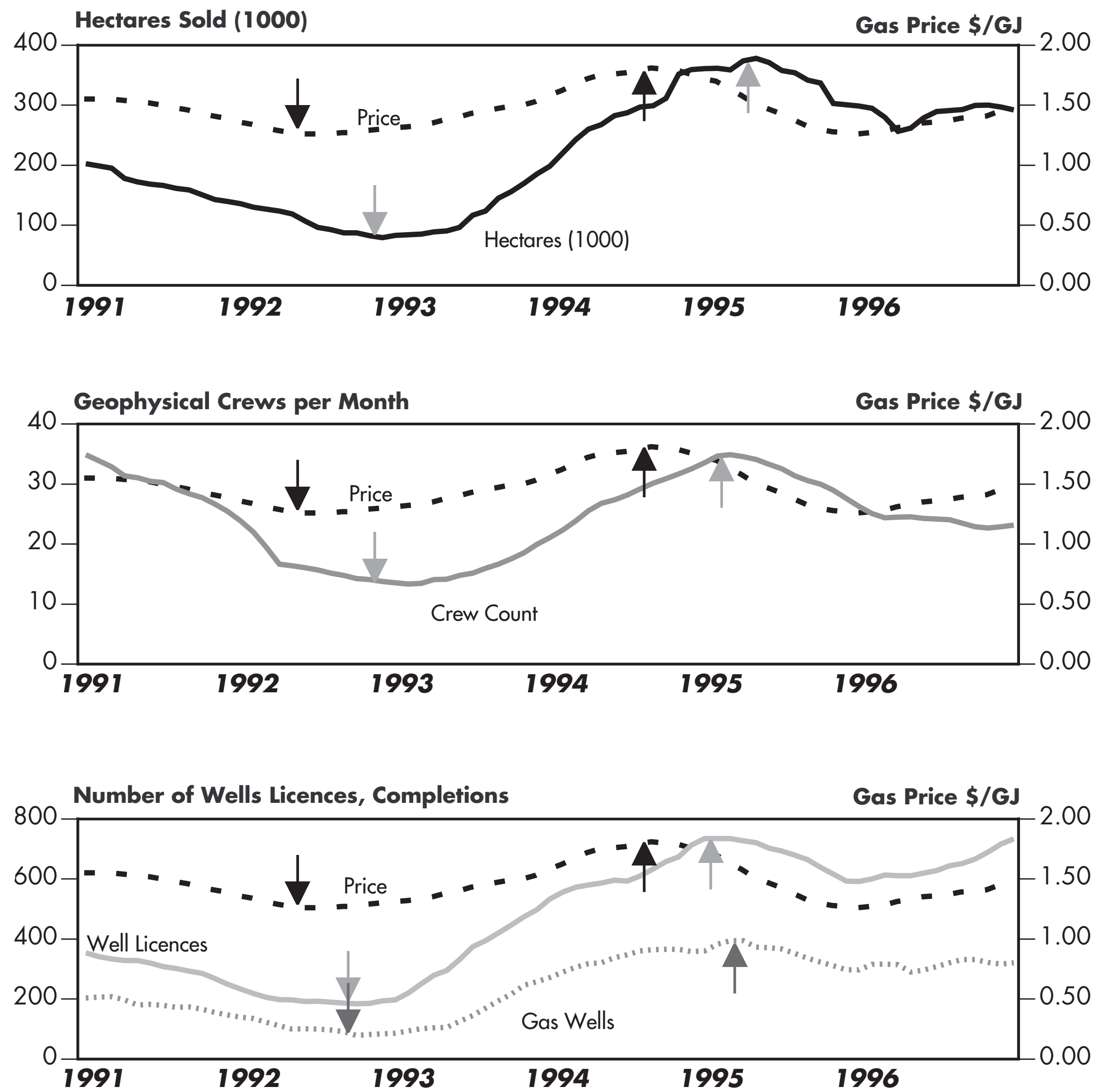
Appendix I provides a more complete description of the defined NEB regions and areas, as well as the geological formation groups defined for this study

The arrows on the chart in Figure 3.1 indicate the peaks and troughs for each curve. A comparison of these highs and lows yields a lag time between the price signal and the response in the activity item being considered. Figure 3.1 suggests the following lag times:

- on the upswing;
  - 7 months for land sales
  - 6 months for geophysics
  - 7 months for gas well drilling completions
  - 4 months for issuance of gas well licenses
- and, on the downswing;
  - 6 months for land sales
  - 8 months for geophysics
  - 4 months for gas well drilling completions
  - 4 months for issuance of gas well licenses.

F I G U R E 3 . 1

Western Canada Gas-Directed Activity vs Price

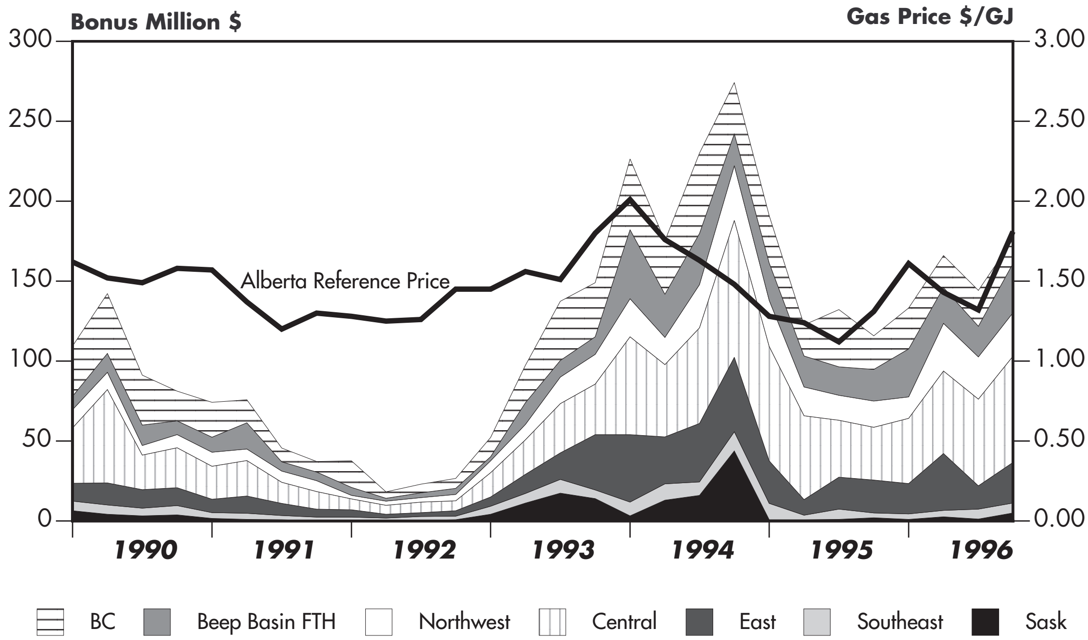


Changing trends in producers' plans can be detected most promptly by examining the swings in the number of well licences, with the lag time between a swing in price and industry response on the order of four months, reflecting primarily that only administrative processes are involved. For the other variables - land sales, geophysical crew count and drilling completions - the lag time varies between six and eight months due to seasonality and the longer lead time required to contract for equipment.

It is interesting to note that the lag in producers' response, with respect to drilling completions, is on the order of three months longer on the upswing in activity than on the downswing. This is thought to be due to an increase in the length of time required to contract for equipment and crews when services are in high demand.

FIGURE 3.2

Western Canada Land Sales Results
Estimated Gas Intent Bonus Paid By Quarter



3.2 Land Sales and Geophysical Activity

In this section we investigate producers' acquisition of rights for development and exploration, as well as levels of geophysical activity. The regional distribution of this activity and shifts in this distribution over this time period are also addressed.

3.2.1 Land Sales

Provincial land sales data, which set out the location, size, price and rights associated with the parcels sold, provide a good indication of the interest that the industry has in exploring in a given area. The prices paid for the rights reflect industry's views on the perceived potential of the property and the level of competition for that property. The relative level of gas-related land sales activity for each of our study areas should correlate to future gas drilling levels in these areas. Thus, by monitoring the land sales activity we can get an early indication of possible shifts in the distribution of future gas drilling.

In response to the upward price swing starting in late 1992, producers rapidly accelerated gas-directed land rights purchases. This resulted in a pronounced increase in the prices paid for land rights, with the largest increases in the East Alberta and Central Alberta regions, and to a lesser extent the Northwest Alberta and the British Columbia regions (Figure 3.2). The level of expenditure for land acquisition remained at a relatively high level, even after the decline in the ARP starting in early 1994, in parallel with the trends noticed for drilling.

DETERMINATION OF GAS-INTENT

THE approach taken is to allocate the geophysical crew count data and land sales data to the nine NEB regions and then further split the data between oil and gas based on the exploratory intent within each of these regions. It seems reasonable to proportion the current activity on the basis of the producers' past exploratory intent, as measured by the ratio of total successful gas exploratory metreage drilled to total successful exploratory metreage drilled for both gas and oil wells. While this method of determining gas intent may not be precise, the resulting estimate of gas-intended land sales and geophysics activity does provide some insight on changing exploration patterns. Table 3.1 shows the gas exploratory intent for each of the nine regions of our study, for the years 1992 to 1996.

TABLE 3-1

Proportion of Total Successful Exploratory Drilling Estimated To Be Gas Directed

Region/Year	1992	1993	1994	1995	1996
B.C. - Plains	0.73	0.64	0.74	0.76	0.58
B.C. - Foothills	1.00	1.00	0.96	1.00	1.00
Southeast Alberta	0..49	0.53	0.58	0.53	0.49
East Alberta	0.53	0.65	0.78	0.73	0.71
Central Alberta 1996	0.43	0.52	0.64	0.65	0.67
Northwest Alberta	0.40	0.55	0.59	0.73	0.66
Alberta Deep Basin - Foothills	0.79	0.58	0.85	0.81	0.82
Southwest Saskatchewan	0.51	0.82	0.62	0.08	0.10
West-Central Saskatchewan	0.52	0.18	0.74	0.26	0.16

3.2.2 Geophysical Activity

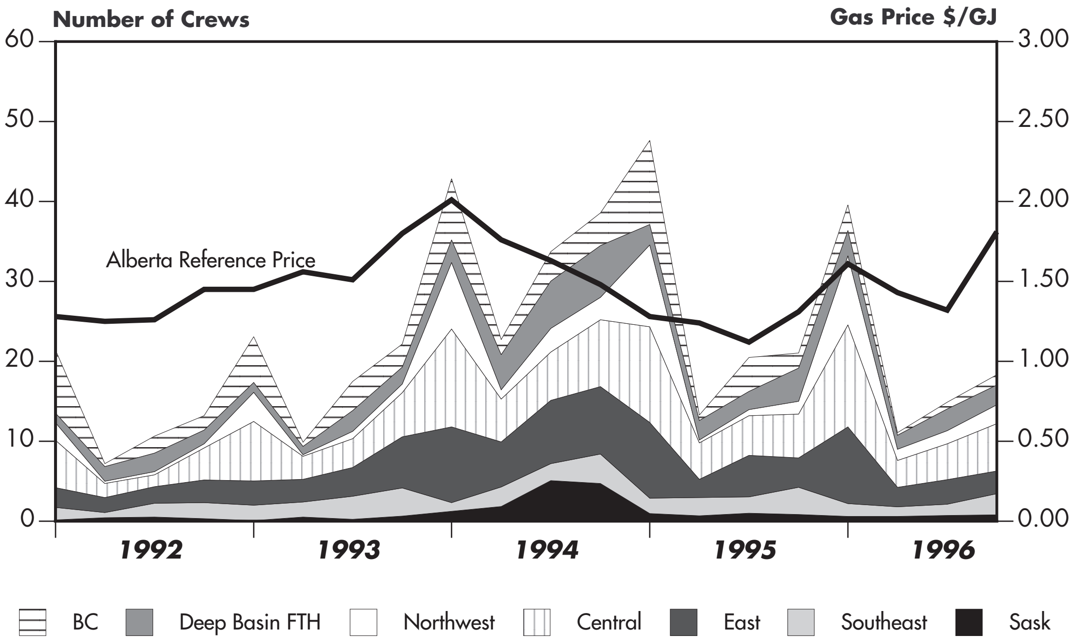
Monitoring the location and level of geophysical activity, as measured by the monthly geophysical crew count, provides a reasonable tool for judging producers' relative level of interest in a given area. It also serves as a rough indicator of the level of subsequent drilling activity.[10]

Producers responded aggressively to increased gas prices as the number of active crews in 1994 and 1995 was double that of 1992 (Figure 3.3). This aggressive response is particularly evident over the 1993/1994 period, and was concentrated primarily in the shallow gas regions and in Central Alberta. While interest in the shallow gas areas continued into 1995, a shift towards greater activity within the B.C., Alberta Deep Basin-Foothills and Northwest Alberta regions is evident in 1994 and in 1995. Some of this shift is due to a move to search for larger, deeper targets in these regions.

[10] The seismic crew count data is taken from Nickle's *Petroleum Explorer* which includes information on the location for each active crew and the type of survey being carried out.

FIGURE 3.3

Western Canada Estimated Gas Intent Geophysical Activity vs Gas Price



For most of 1995 and into 1996, activity in all areas of Western Canada was down, compared to 1994. The shallow gas regions show a slight increase in activity in the later part of 1995. This indicates that producers' interest in pursuing quick deliverability in the shallow gas regions is continuing.

3.3 Drilling - Exploratory and Development

This section examines the pattern of industry response to the changing gas market conditions, in terms of the level, type and location of drilling activity. Drilling activity is a capital-intensive activity parameter and is a valid, results-oriented indicator of producers' responses. The discussion of gas drilling activity addresses the following topics:

- the extent of producers' shift to drilling wells primarily for immediate deliverability;
- the extent to which producers shifted their intent from shallower to deeper plays after mid-1994; and,
- the distribution of drilling by NEB region, NEB geological zone and well type (whether exploratory or development).

To present a clearer picture of the distribution of the exploration and development activity, the drilling data have been divided into "shallow gas" and "deeper gas" designations. In most cases, the gas well drilling statistics are presented in terms of kilometres drilled, in addition to the number of wells drilled.

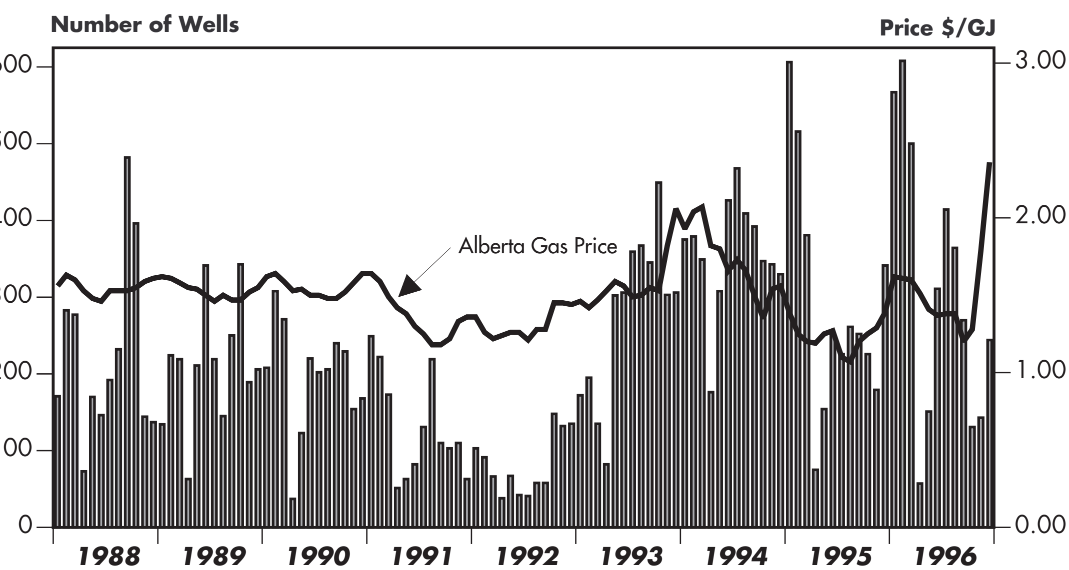
After slumping to a 20-year low in 1992, drilling levels rebounded dramatically in 1993 within the WCSB, reaching a record-breaking 5 332 gas wells in 1994 (Figure 3.4). In 1995, in the face of lower gas prices, the total drilling effort for the WCSB declined by about 30 percent, followed by a slight increase in 1996. Even though the well count declined from the record levels of 1994, the drilling effort on average over the 1993-1996 period represents a significantly higher level of drilling activity than that of the pre-1992 period. This observation suggests that producers were motivated to maintain the pace of drilling activity by factors other than market price alone.

3.3.1 Drilling Activity - Type

The response by producers to price swings in the 1992 to 1996 period is manifested in two ways. First, the number of wells drilled increased dramatically, setting new records of well count and metres drilled. Second, the split between exploratory and development drilling shifted to favour development wells (Figure 3.5). Initially producers responded to rising demand and increasing prices by concentrating efforts on quickly bringing on additional capability, or "drilling for deliverability". The degree of focus on development drilling continued through to the end of the period, with the development drilling accounting for approximately 60 percent of total successful gas well metreage drilled. In aggregate, producers directed two-thirds of their drilling efforts to development drilling during this activity cycle

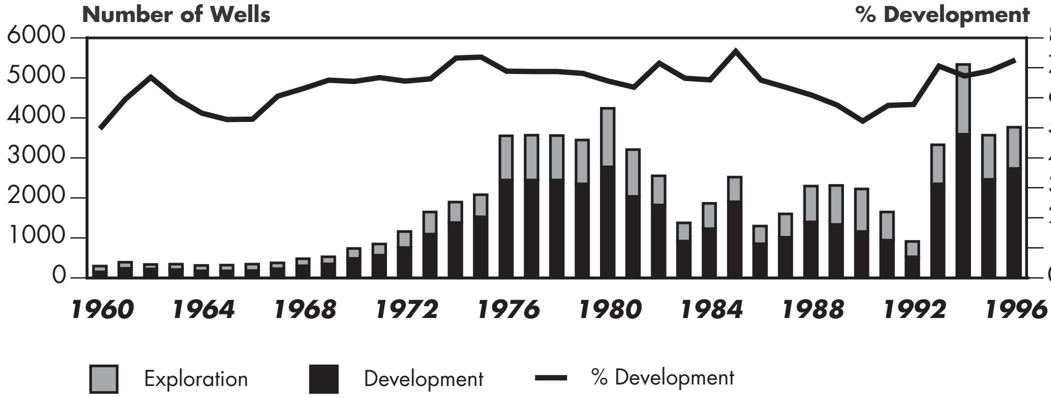
FIGURE 3.4

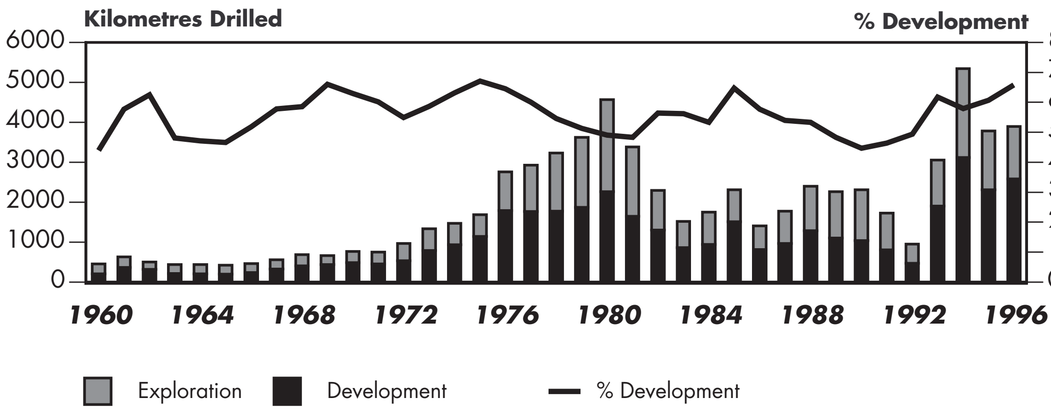
Western Canada Monthly Gas Well Completions vs Gas Price



F I G U R E   3 . 5

Western Canada Annual Gas Well Completions





3.3.2 Distribution by Region

Producers' quick response to the markets' signal for additional production is most evident in the abrupt upswing of development drilling in the shallow gas areas, as well as in the Central and East Alberta regions (Figure 3.6). In 1993, producers' development drilling effort in the shallow regions exceeded development drilling in the remainder of the entire basin. Significant development drilling is also evident in the Northwest and Deep Basin-Foothills regions of Alberta.

On the exploration side, producers' drilling efforts were primarily concentrated in the Central Alberta region, followed by the Northwest Alberta, Deep Basin-Foothills, Southeast Alberta and East Alberta regions (Figure 3.7). Most regions show a substantial increase in activity in 1993 over 1992, with the activity levels peaking in 1994 before dropping somewhat in 1995. In 1996, the Northwest, Deep Basin-Foothills, and Central regions of Alberta experienced a slight increase in activity over 1995, while the remaining regions showed slight decreases.

The shallow gas region of Southwest Saskatchewan behaved somewhat differently, with activity peaking in 1993, declining slightly in 1994 and falling sharply to a level of about 60 000 metres drilled in 1995. This sharp drop reflects the completion of major development projects in the Ingebright and Firefight fields, rather than a change in trends.

FIGURE 3.6

Development Drilling by Region

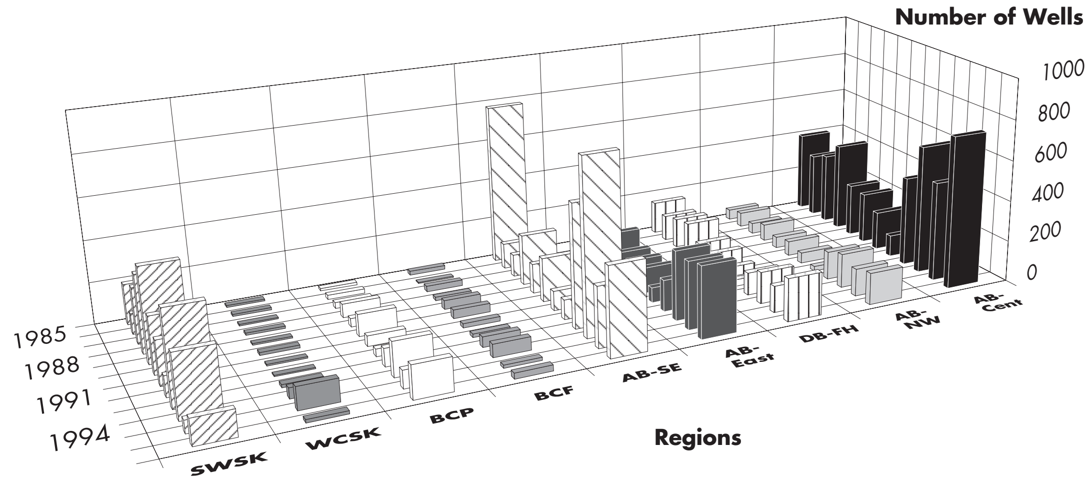
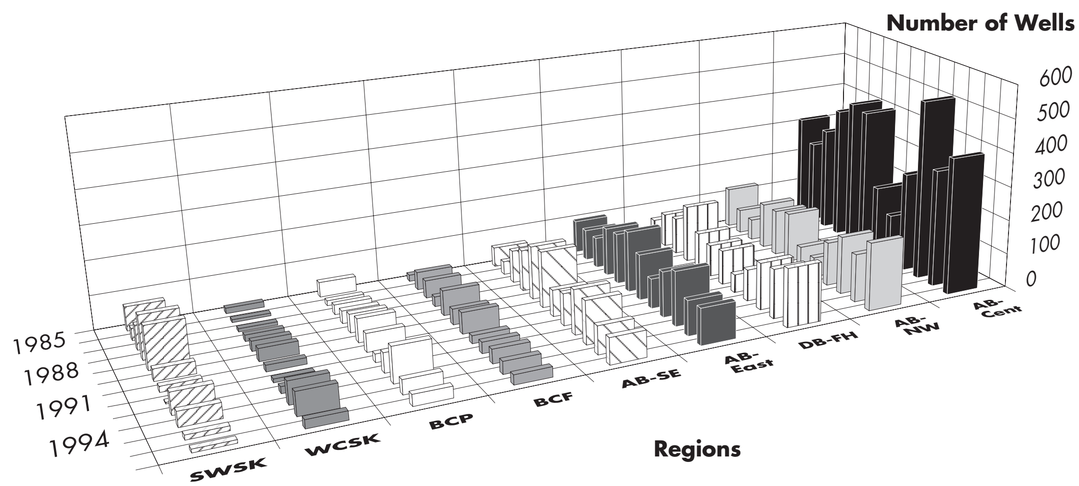


FIGURE 3.7

Exploratory Drilling by Region



Index to Abbreviations

SWSK	Southwest Saskatchewan	**AB-East**	East Alberta
WCSK	West-Central Saskatchewan	**DB-FH**	Deep Basin - Foothills
BCP	B. C. Plains	**AB-NW**	Northwest Alberta
BCF	B.C. Foothills	**AB-Cent**	Central Alberta
AB-SE	Southeast Alberta		

DRILLING STATISTICS - EFFECT OF SHALLOW GAS DEVELOPMENT

The shallow gas regions of Southeast Alberta and Southwest Saskatchewan comprise about 60 percent of the total gas well count in the WCSB. In any discussion of gas well drilling statistics, it is important to distinguish between the shallow gas and the deeper gas regions. In our "shallow gas" designation we include all gas wells found in the Southeast Alberta and the Southwest Saskatchewan regions, the vast majority of which fall within the Medicine Hat-Milk River zone (MH-MR). Within the WCSB, the producing gas well count in 1995 for the shallow gas regions represents about 77 percent of the total number of producing gas wells, with about 90 percent of these being development wells. Aggregate WCSB or Alberta-well-data do not properly reflect the differences that exist between the shallow gas and deeper gas regions. For instance, in 1994 approximately 900 exploration wells were drilled in Alberta, excluding the Southeast Alberta region, representing about 38 percent of total gas wells drilled in Alberta in that year. If we include the Alberta Southeast region in this total, the exploration wells represent only 26 percent of the total.

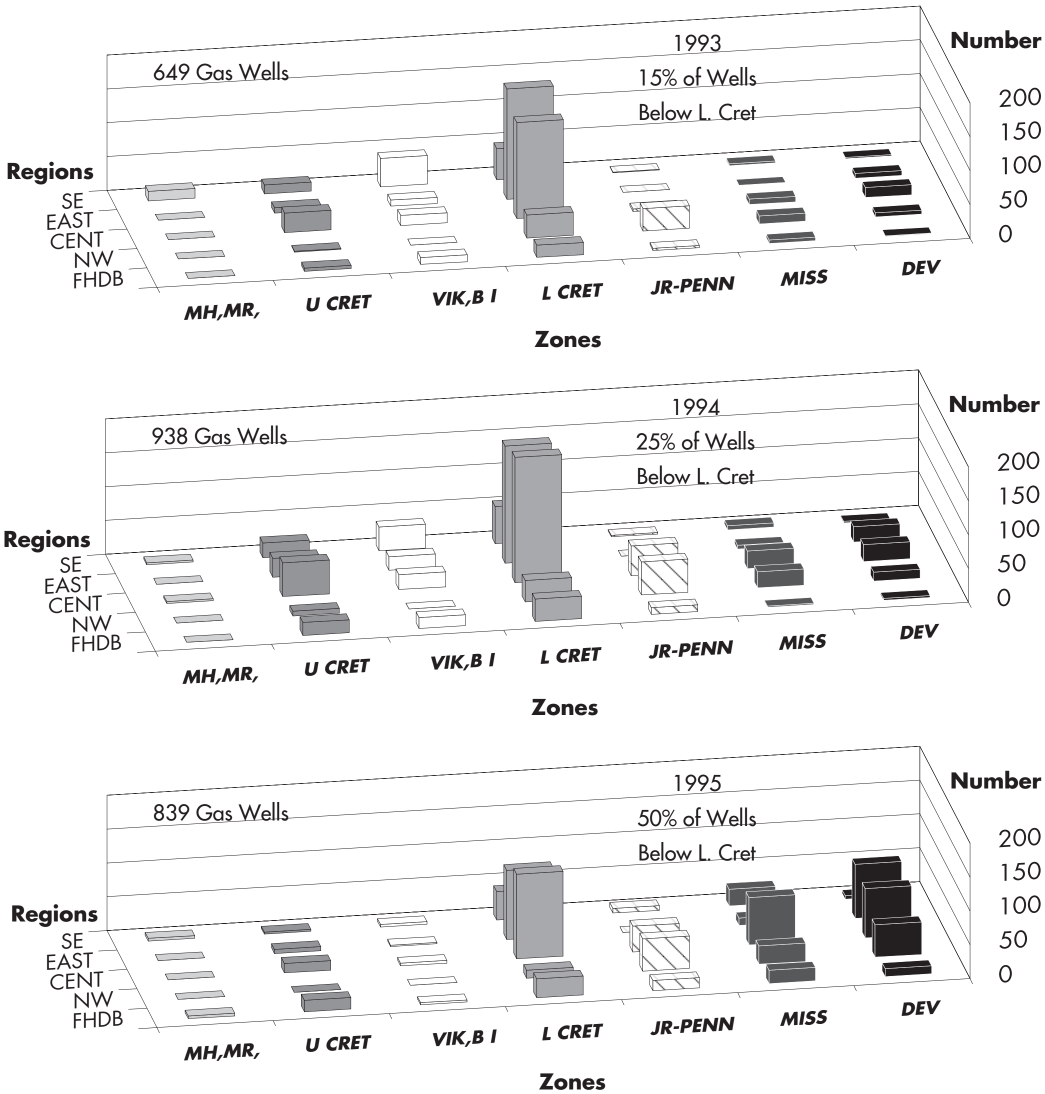
3.3.3 Distribution by Zone

Another important indication of changes in producers' strategies for finding and developing gas reserves is the preferred target zones within the various regions. In general, shallower targets are cheaper to drill and develop, but have relatively smaller reserves and lower productivity per well. In contrast, targets in geologically older and deeper horizons generally yield larger reserves and higher productivity per well. This section presents a discussion of the geological distribution of Alberta's successful gas exploration and development drilling, for the years 1993 through 1995.

The distribution of Alberta's exploratory gas well drilling by NEB area and zone is shown in Figure 3.8. The charts illustrate the shift of exploratory drilling to the three deeper zones below the Lower Cretaceous ("L. Cret") - the Jurassic - Pennsylvanian, the Mississippian, and the Devonian - over this period of time. These three zones accounted for 15, 25 and 50 percent of the total gas exploratory drilling for the years 1993, 1994 and 1995 respectively. The bulk of this increase in deeper drilling occurred in the Mississippian and Devonian groups in the East Alberta and Central Alberta areas. There was also a noticeable increase in the well count for the Jurassic-Pennsylvanian group, with 44 wells in 1995, compared to only four wells drilled in 1993.

F I G U R E 3 . 8

Alberta Exploratory Wells By Region and Zone



A L L O C A T I O N O F D R I L L I N G B Y Z O N E

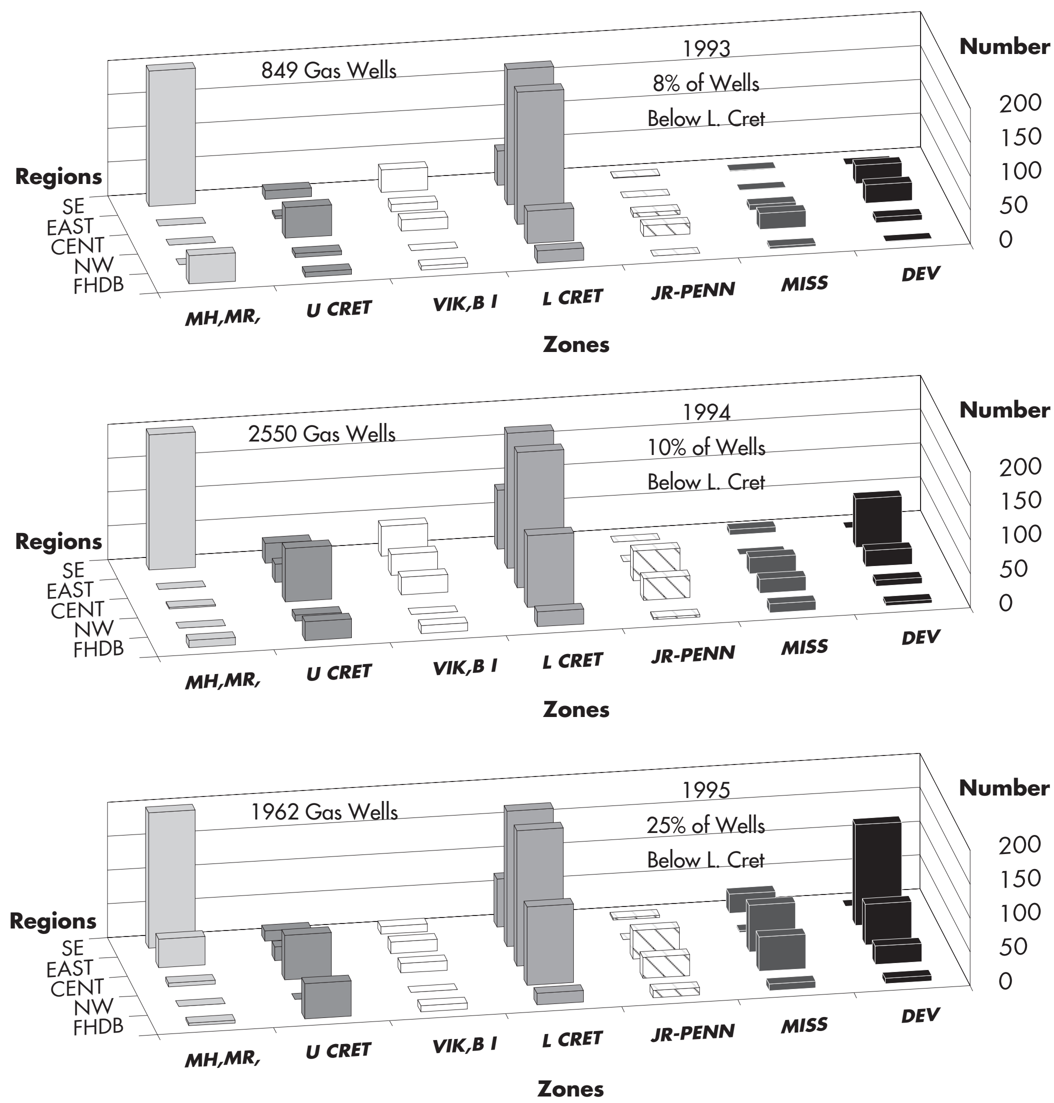
THE various geological zones within Alberta have been allocated across the seven NEB zones.[11] The allocation to a geological zone is based on the formation at total depth ("TD") of each gas well. That is, a well is assigned to an NEB zone based on the geological formation that exists at the point of the well's deepest penetration. Our analysis of the drilling data indicates a good correlation between a well's assignment to an NEB zone and the producing formation for that well. In many cases, there is more than one zone per well, with formations higher in the well bore also capable of production. In most cases, there is a producing event associated with the assigned NEB zone.

[11] The NEB gas regions and zones are discussed in Appendix I.

Figure 3.9 illustrates the distribution, by NEB region and zone, of Alberta's successful development gas wells for the years 1993, 1994 and 1995 respectively. The important role played by the Medicine Hat-Milk River-Second White Specks zone within the Southeast Alberta region is evident, accounting for 48 percent of gas development drilling in Alberta in 1993. In 1994, some 2550 successful gas development wells were drilled in Alberta with 1044 wells, or 41 percent, falling within this region/zone intersection. The increased contribution of the Lower Cretaceous zone in 1994 over 1993 is evident, as is a slight increase for the three deeper zones. In 1995, the Southeast Alberta region well count abated sharply; however, the well count for the Lower Cretaceous zone remained at near 1994 levels. The relative increase in development drilling for the three deeper zones is evident, going from 10 percent in 1994 to 25 percent in 1995, with the well count nearly doubling, rising from 255 to 492 wells. This shift to production from deeper horizons is consistent with the pattern for exploratory drilling.

FIGURE 3.9

Alberta Development Wells By Region and Zone



3.4 Trend to Higher Activity Levels

In the years following deregulation, productive capacity exceeded demand by a wide, although gradually decreasing, margin. After productive capacity and demand came into closer balance in the early 1990s, the characteristics of gas supply changed. The expected "cause and effect" relationship between prices and activity levels was generally consistent up to 1994, that is, producers responded to swings and market prices with a corresponding change in activity levels.

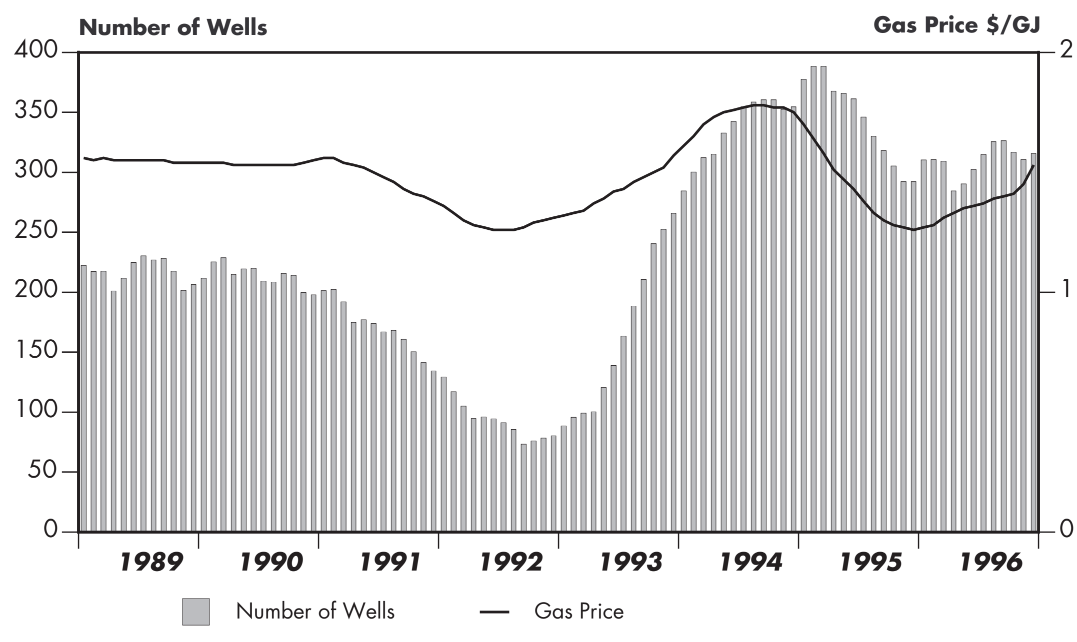
This price-activity relationship appears to have changed in the last two years. Although prices declined in 1995 to match the low price levels of 1992, producers' drilling activity in late 1995 to 1996 remained at a much higher level than seen prior to 1993 (Figure 3.10). This higher activity level is thought to be due to several factors, such as:

- steadily increasing demand;
- decreasing productivity per well;
- producers' ongoing contractual commitments to supply gas;[12]
- land obligations which call for exploration and development expenditure;
- the need to meet investor expectations;
- the need to maintain cash flow; and,
- the need to replace reserves.

The pattern of higher activity levels continued into 1996, supporting the earlier projection of the need for sustained higher levels of drilling activity.

FIGURE 3.10

Western Canada Gas Drilling vs Gas Price - 12-Month Moving Average



[12] Signed contracts with purchasers for specified daily volumes of gas over a specific term for a specific total volume.

TRENDS IN GAS WELL CONNECTION AND PRODUCTION

We examined various aspects of gas production for the period 1992 to 1996 to identify changing characteristics of gas supply within the WCSB. This examination included the following items:

- trends in the vintage of newly-connected wells;
- the pace of connecting wells for production;
- trends in initial well productivity; and
- trends in production decline rates.

The regional distribution of these aspects is also provided for nine gas regions within the WCSB. This breakdown by region is required to capture important differences and to identify important details that would be masked if the data were aggregated by province or for the whole of the WCSB.

4.1 Connecting Gas Wells For Production

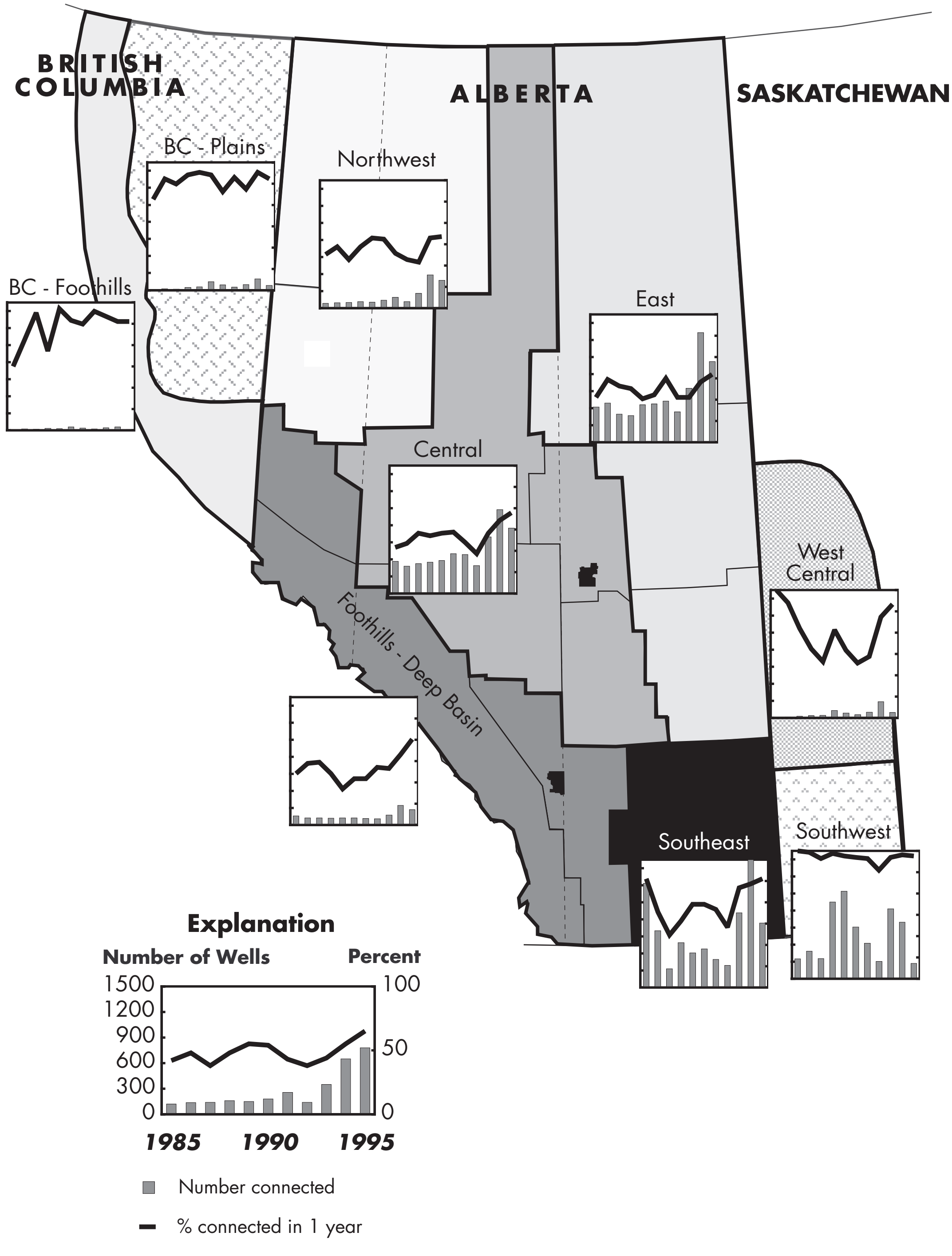
As described in the previous sections, the gas industry responded to market conditions, characterized by a narrowing margin between supply and demand, coupled with attractive gas prices, by drilling an unprecedented number of exploratory and development gas wells in the WCSB. This section provides an analysis of the pace and distribution of well connections, which are important factors in assessing the overall supply situation. This analysis includes the vintage of the well being connected, whether recently drilled or drawn from the stock of older wells, the time between drilling a well and connecting it for production and the regional distribution of the wells.

4.1.1 Connection Rates and Time to Connect

One very evident feature of producers' response to changing markets conditions was the rapid increase in the pace of connecting wells for production, especially in the early years of the study period. A review of the connection time, or the time interval between drilling a well and connecting it for production, indicates a significant shortening of the connection time for most regions during this period.

F I G U R E 4 . 1

Western Canada Gas Well Connections



From 1993 to 1994, some 9 300 wells were connected for production, compared to only 3 600 wells over the 1991 to 1992 period. Additional insight into producers' practices in connecting wells for production can be obtained through regional comparisons of the magnitude and pace of well connections.

Figure 4.1 illustrates the number of wells connected per year over the period 1985 to 1995, for each of the nine NEB regions. A curve is shown for each region, representing the percentage of wells connected within one year of drilling. Typically, the length of time between completion and connection tends to decline towards a minimum for each region, reflecting the operating logistics of each. The connection practices vary considerably across the nine regions.

The shallow gas regions of Southeast Alberta and Southwest Saskatchewan have seen a large number of wells connected in the 1993 to 1995 period. Due to the shallow drilling depths involved, and the close proximity to the existing infrastructure, wells in these regions can be drilled and put on stream in a short time. Producers have traditionally turned to these regions to obtain immediate deliverability.

With respect to time to connect, all Alberta regions show a sharp increase, over the study period, in the proportion of wells connected within one year of being drilled, with most regions approaching 50 percent connected for 1995. In B.C., as well as for Southeast Alberta and Southwest Saskatchewan, gas wells continue to be connected within a year at rates of 80 percent or better. In West-Central Saskatchewan, the percentage connected within one year has increased dramatically, reflecting a greater focus on timely connection for this region.

For most regions, significant increases in the number of wells connected over the study period are also apparent, as producers accelerated the pace of connection in response to market conditions. Exceptions are the two B.C. regions, as well as West-Central Saskatchewan, where no significant increase in the number of wells connected is seen.

Caution is needed when comparing the impact on productive capacity of wells connected between the various regions. For example, a newly connected well in the Deep Basin-Foothills region would typically have 40 times the capacity of a well in the Southeast Alberta region. Therefore, a valid comparison between regions of the effect of well connection activity on productive capacity cannot be based solely on well count.

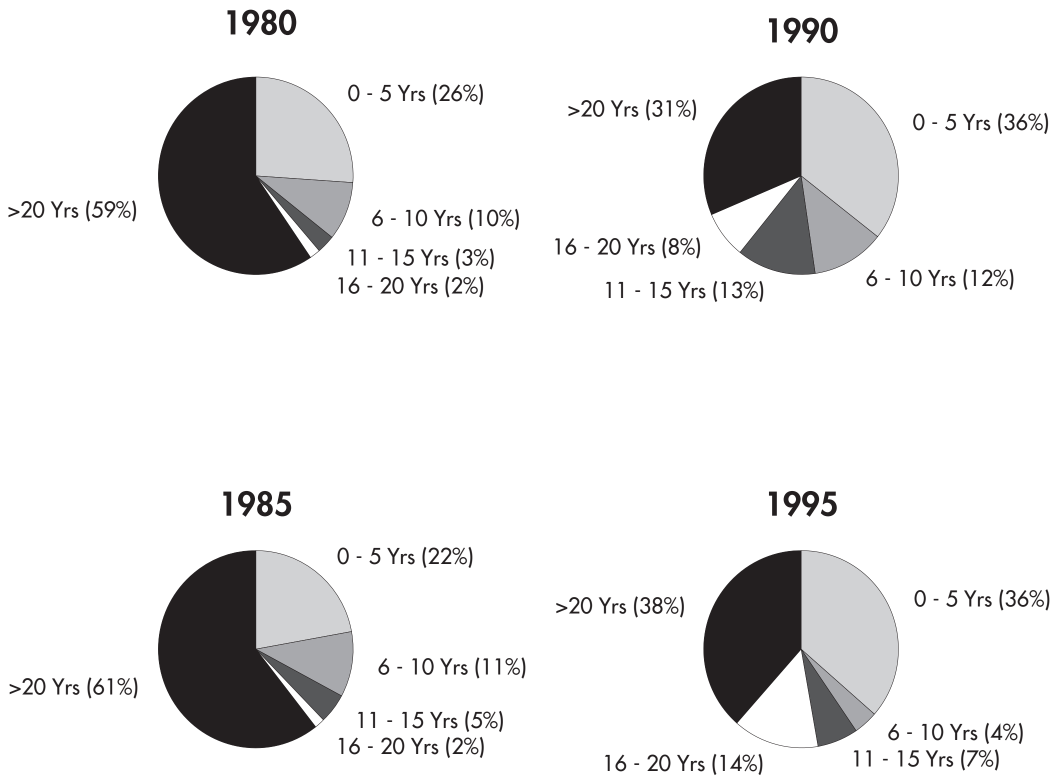
4.1.2 Vintage of Newly Connected Wells

Producers can bring on new supply by means of development of either older pools or of recently discovered pools. The discovery date of the pool in which new wells were connected was examined to determine to what extent producers are relying on older pools to source new gas production (Figure 4.2). This chart indicates that producers continue to rely on older pools, but to a lesser degree than was the case a decade ago.

In 1995, producers turned to pools less than six years old for 36 percent of their new well connections; in 1985, 22 percent of the target pools were less than six years old. In addition, by 1995, only 38 percent of new well connections were in pools greater than 20 years old; compared to 61 percent in 1985.

F I G U R E 4 . 2

Alberta Gas Wells First On Production
By Age Of Pool Discovery

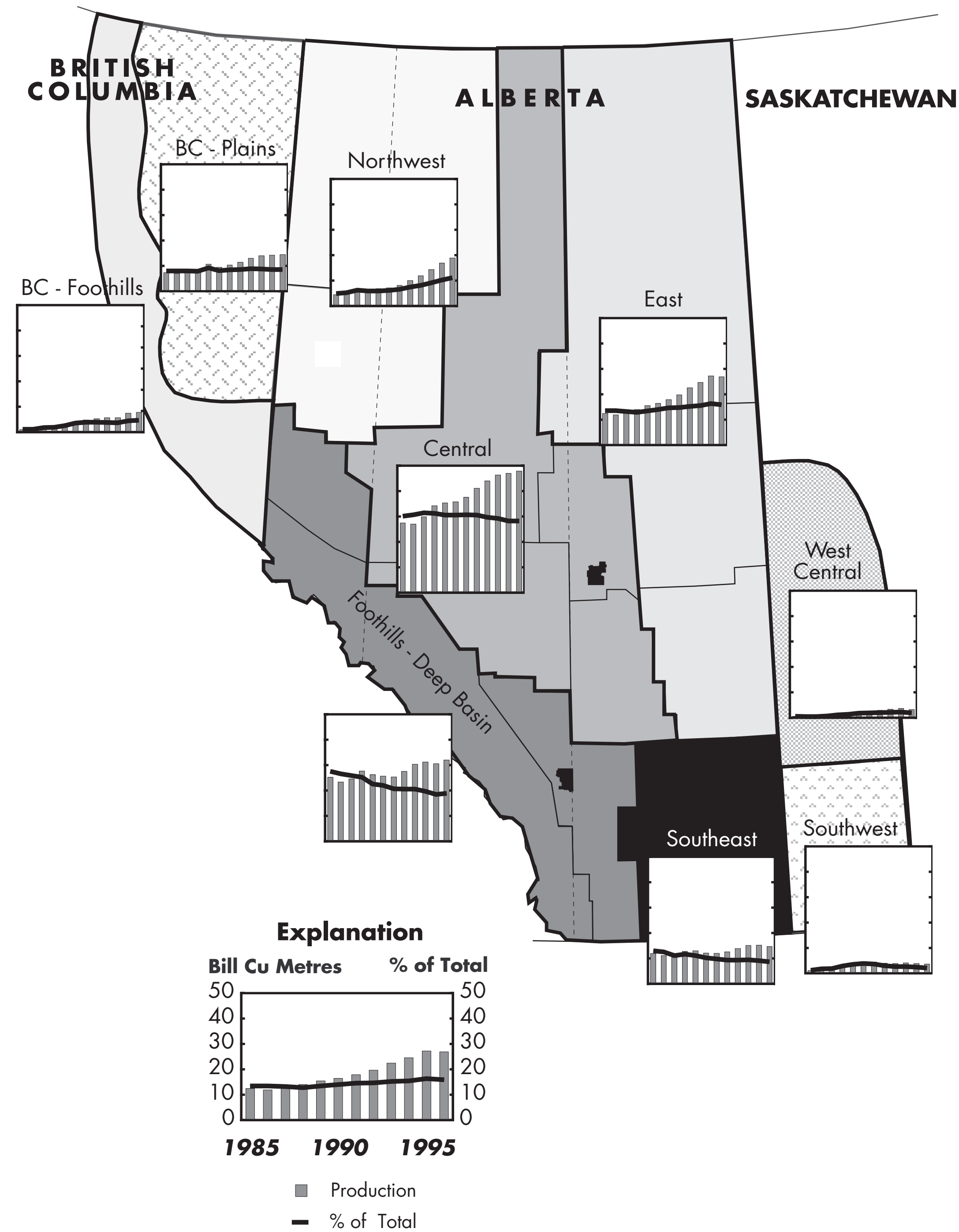


4.2 Natural Gas Production and Producing Rates

This section discusses the effect, on gas production and productive capacity, of a dramatic surge in drilling and well connection activity that occurred from 1993 through mid-1995. A comparison of the initial performance of newly-drilled wells versus older wells is presented, as well as regional variations in production. The assessment of the producing capabilities of these wells is important in determining the effect that connecting new wells will have on total gas deliverability. As in previous chapters, a distinction will be made in certain cases between shallow gas and deeper gas, as well as between development and exploratory wells. Comparisons are also made among the nine NEB regions.

F I G U R E 4 . 3

Non-Associated Raw Gas Production by Region

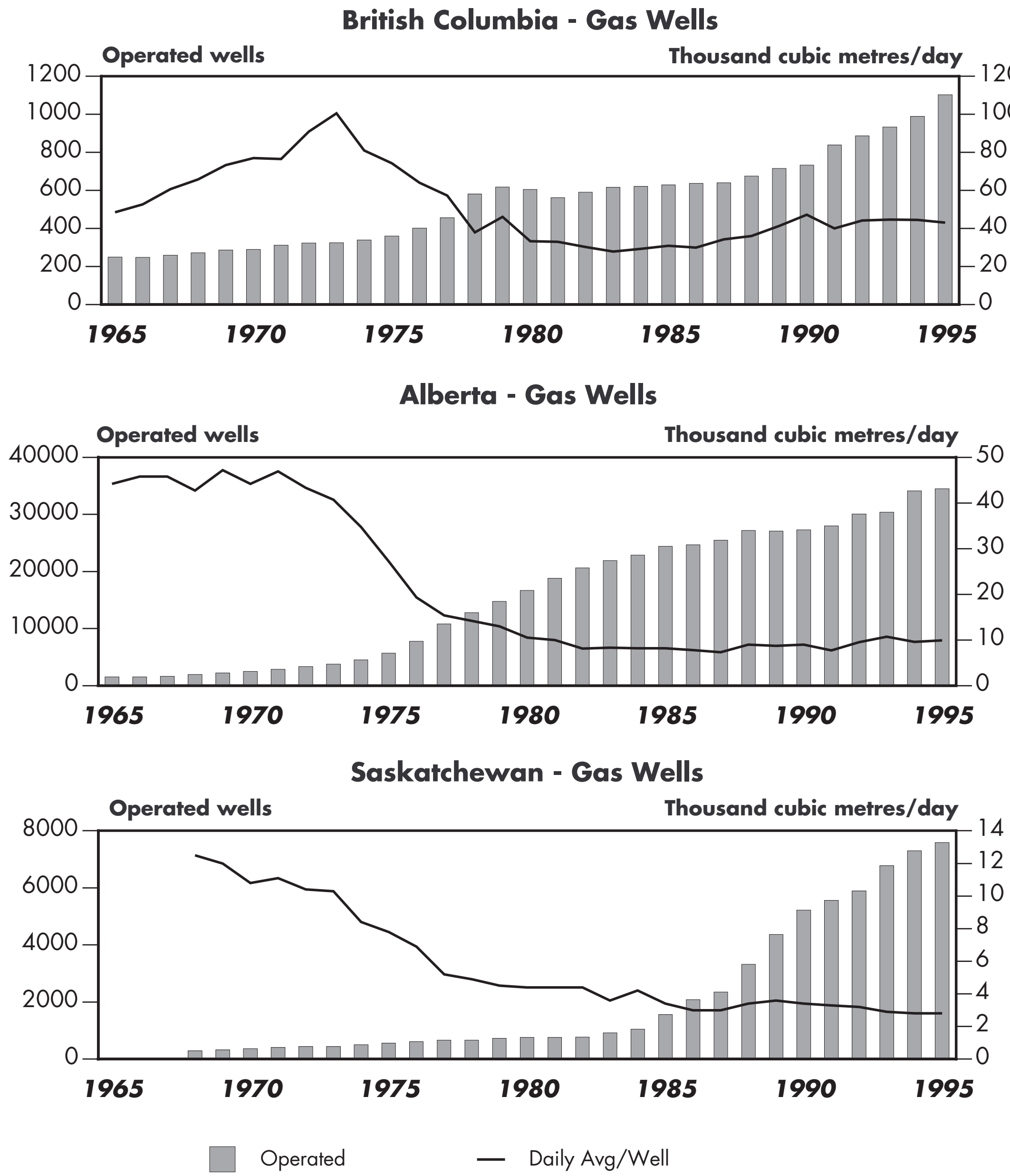


4.2.1 Natural Gas Production Volumes

Figure 4.3 shows the contribution to total production for each of the nine NEB regions. During the 1992 to 1996 activity cycle, producers accelerated production in three major producing regions - Central, East and Northwest Alberta - which together contributed over 50 percent of WCSB supply. More moderate growth occurred in Southeast Alberta, Deep Basin-Foothills, as well as in the BC-Plains regions. Note that the Alberta shallow gas region, which has roughly 60 percent of the total producing gas wells in Alberta, has seen its proportion of production decline to about 10 percent. The Central Alberta region, which has the largest share of total gas production at 29 percent in 1995, has seen its contribution decline very slightly since 1990. The largest year-over-year percentage gain has occurred in the Northwest Alberta region, which has seen its share of production rise from 6 percent in 1990 to about 10 percent in 1995.

FIGURE 4.4

Western Canada Operated Gas Wells and Average Production Rates (Raw)



4.2.2 Operating Wells and Well Rates, by Province

To provide some background for the discussion of the impact of producers' response on production rates over the study period, it is useful to review the historical perspective of the operating well count and average well productivity. Reviewing the record of the last 15 years, producing well counts have doubled in B.C. and Alberta, and have increased ten-fold in Saskatchewan (Figure 4.4). Over the 1992 to 1996 study period, the operated well count increased by 25, 15 and 29 percent in B.C., Alberta and Saskatchewan, respectively. At the end of 1995, some 42 600 producing gas wells were in operation in the WCSB, compared to 34 000 at year-end 1991.

The average well production rates shown represent the average calendar day raw gas producing rates for wells of all ages (Figure 4.4). In general, the effect of declining production rates for older wells is offset by the addition of new wells. With respect to the individual provinces, there is considerable variation in the average well production rates. In B.C., the average rate over the study period has remained relatively constant at about 45 thousand cubic metres per day (1.6 mmcf/d). This represents an increase of 50 percent over 1985 levels and is due to the impact of higher overall demand for B.C. gas, plus the effect of the higher-capability, Monkman-area wells, developed after 1988. In Alberta, the rates increased from 9 thousand cubic metres per day (0.3 mmcf/d) to a level of 11 thousand cubic metres per day (0.4 mmcf/d), a 33 percent increase over the 1992 and 1993 period. This reflects the higher rates-of-take implemented to meet the rapidly increasing demand for gas over this period. Subsequently, average well rates fell slightly, due primarily to a greater emphasis on developing gas supply in the Southeast Alberta shallow-gas region, where wells generally have lower productivity. For Saskatchewan, the average well rate dropped by 20 percent over the 1992 to 1993 period due to increased development activity in the Hatton and adjacent areas of Southwest Saskatchewan. Rates then levelled out at about 3 thousand cubic metres per day (0.1 mmcf/d).

4.2.3 Production Decline Rates

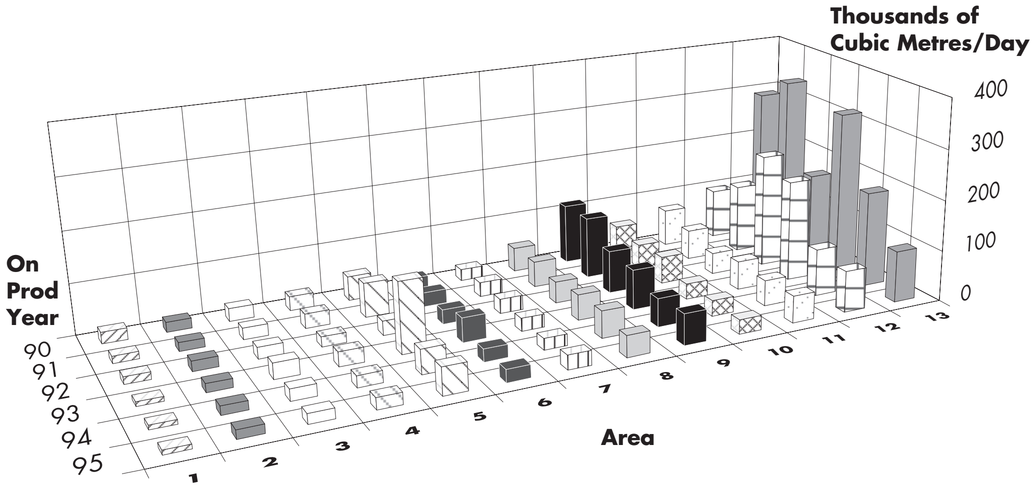
A gas well's productive capacity depends primarily on the nature and producing history of the reservoir, coupled with the characteristics of the well completion and field facilities. Thus, trends observed in production rates and production decline rates provide some indication of producers' actions to optimize the pace of production to meet market opportunities. As well, they provide an indication of the quality and capability of the reservoirs.

To determine the level of activity required to sustain current production levels, the initial producing rates of wells being connected for production were examined. Figure 4.5 provides the initial well production rates, averaged for each of the 13 areas in Alberta. Over the period 1992 to 1995, a trend to lower initial capability is evident for most areas, with the average first-year production rate declining by 10 percent. This trend is due to the fact that many of these wells are drilled into already producing pools, and encounter increasingly lower reservoir pressures over time. To some extent as well, newly discovered pools are of lower quality than those found a decade ago.

Typically, a gas well in the WCSB will exhibit a decline in its productivity within the first 12 to 18 months of production. The majority of producing gas wells in the WCSB are in the decline phase of their producing life, and therefore, producers are required to bring on additional wells in order to maintain deliverability. Thus, the rate at which well productivity is declining is an important factor when considering the level of activity that must be sustained to meet future gas demand.

F I G U R E 4 . 5

Alberta Average First-Year Producing Rates

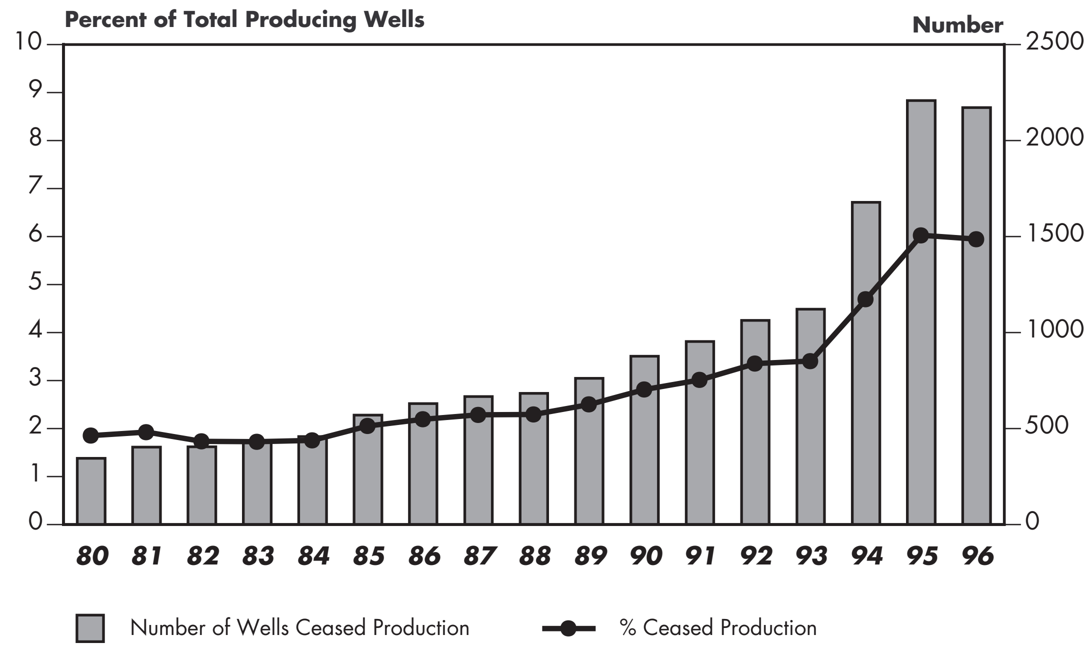


The rate at which wells become depleted and are removed from production is also an important component of the overall decline in production from currently producing wells. This component will become increasingly important over time because, as the total operated-well count increases, so too does the number of wells that reach full depletion and are removed from production (Figure 4.6). In addition, with the higher current rates-of-take, the average producing life of wells is decreasing, which further impacts the overall decline.

To illustrate these observations for Alberta, Figure 4.7 shows the contribution made to total gas production by wells brought on each year. As a consequence of the steady decline in the production rate from the inventory of producing wells at any point in time, combined with the growth in demand, producers have been forced to accelerate the development of new production each year to maintain supply. To meet this requirement, producers bring on additional supply by drilling development wells into both newly-connected and older pools; and, to a lesser degree, previously-unconnected wells are brought on production. To illustrate the degree of current dependence on newly developed production, note that as of year-end 1995, roughly 36 percent of production came from wells connected in 1993, 1994 and 1995 (Figure 4.7). Figure 4.7 also illustrates a trend to ever increasing decline rates as we move forward in time.

FIGURE 4.6

Alberta Gas Wells - Annual Percent Wells Ceased Production vs Number Producing



Note: Data for 1996 is for partial year only

FIGURE 4.7

Alberta Raw Gas Production By On-Production Year

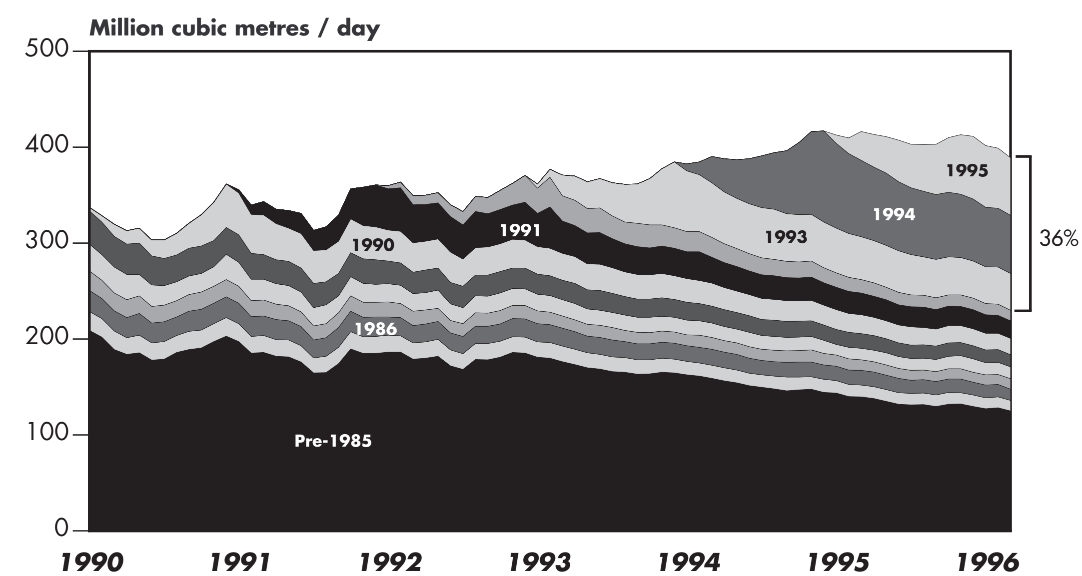


Table 4.1 shows the results of further analysis of the production decline data utilized for Figure 4.7. The decline rates are based on plots of cumulative production versus the active-day rate for all wells that first come on production in a given year. An example of such a plot for 1990 is provided in Appendix III. For wells grouped in this manner, that is by on-production year, any trend to declining rates usually doesn't become apparent until the second year. Thus, the values for 1994 and 1995 are estimates based on early indications of the decline trend. The decline of each group shown on Table 4.1 was weighted by each groups' portion of total 1995 gas production (excluding solution gas). Based on these calculations, the overall average decline rate for Alberta natural gas production at year-end 1995 was determined to be 18.1 percent.

TABLE 4-1

Estimation of Overall Decline of Alberta Production

On-Prod Year	% Decline	% Prod Dec, 1995	Prod Weighted Decline (%)
Pre-85	8.5	30	2.6
1985	9.5	3	0.3
1986	10.5	4	0.4
1987	13.5	3	0.3
1988	16.0	3	0.5
1989	19.0	4	0.7
1990	19.2	5	1.0
1991	20.8	5	1.0
1992	32.2	3	1.0
1993	24.3	11	2.7
1994	25.0*	18	4.6
1995	25.0*	12	3.0
All years		100	18.1

*Estimated Value

ADDITIONS TO RESERVES AND PRODUCTIVE CAPACITY

This chapter presents the results of an analysis of the impact of gas well drilling on reserves additions and productive capacity over the study period. Significant additions to gas reserves and productive capacity in the WCSB have resulted from producers' recent exploratory and development drilling efforts.

As noted previously, the industry has drilled many wells during the study period. It would be of interest to have a timely estimate of the overall impact of the drilling effort on reserves replacement and supply, and to determine the regional and geological distribution of this impact. However, since these types of estimates are not readily available, the Board developed methodologies, or models, to yield an early estimate of reserves additions and productive capacity. These methodologies provide an estimate of reserves found and productive capacity added per successful gas well drilled, and are based on statistical analyses of gas well drilling, reserves and producing rate data. These estimates can be calculated at any point in time, given the latest well-completions data. These methods are not intended to replace more rigorous analytical methods of reserves and productive capacity determination, but are rather intended to provide the ability to quickly assess the impact of recent drilling. A more complete description of these methods, including a discussion of the regional and geological distribution of the results obtained, can be found in Appendices Two and Three. The distribution of results was analysed as there are significant differences in the reserves and producibility characteristics between the various regions and geological zones.

5.1 Additions to Reserves

It usually takes two to three years after discovery before all pools found in a specific discovery year are fully reported in the public gas reserves databases. This delay is related in part to the requirement for many newly discovered pools that their reserves assignments be held confidential for a one-year period. An additional consideration is the time required for the regulatory agencies to assess the 1 000 or so gas pools discovered on average each year.

Gas Pool Counts

T A B L E 5 . 1

Alberta Non-Associated Gas Pool Counts, 1985 to 1994

Year of Discovery	Year of Database 1989	1990	1991	1992	1993	1994
1985	681	700	715	731	742	727
1986	536	550	571	586	585	578
1987	565	581	606	624	632	618
1988	782	876	893	899	896	884
1989	142	727	743	749	747	746
1990		62	951	1031	1043	1021
1991			42	769	759	768
1992				37	491	508
1993					73	863
1994						137
1995						

An analysis of gas pool counts, by reporting year and year of discovery, is shown above. Note that the 1989 database reported only 142 gas pools discovered in 1989, while the 1991 database indicates 743 gas pools were discovered in 1989.

The estimates derived by the Boards' statistical reserves estimation methodology are based on the record of reserves discovered over the period 1980-1994[13], with reserves credited back to the year of discovery. It should also be noted that the estimates provided by this method pertain to new discoveries only and cannot be compared directly to the annual reserves additions reported by the provincial agencies. In their reserves reports, the provincial agencies include revisions to existing reserves estimates stemming from re-evaluation as well as from development drilling.

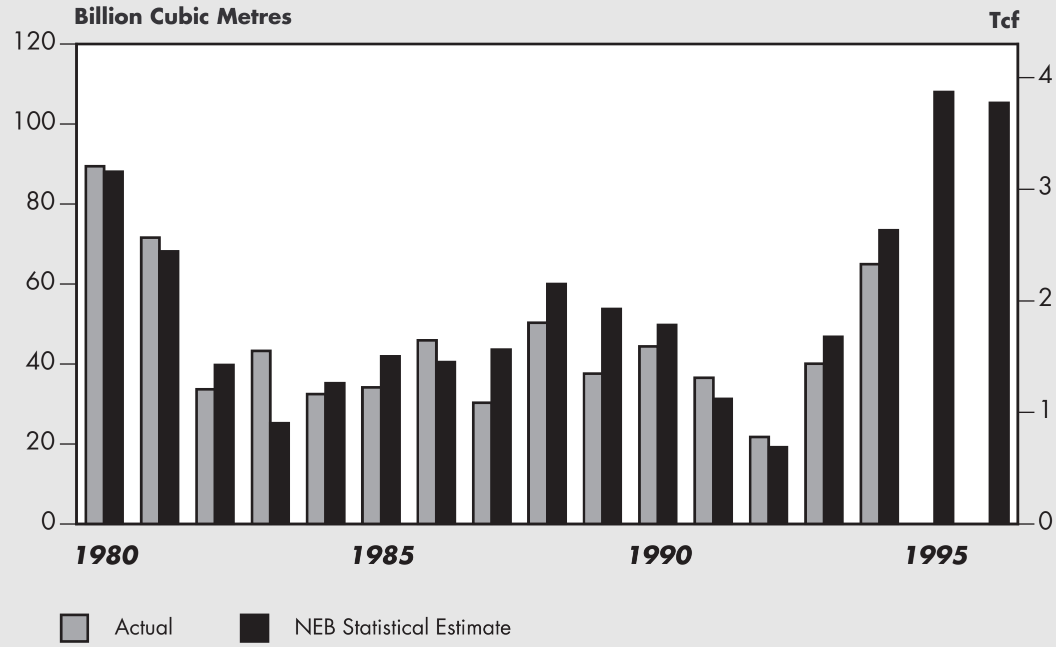
The results from this model suggest reserves additions of 73.5, 108.0 and 105.3 billion cubic metres (2.6, 3.8 and 3.7 Tcf) for 1994, 1995 and 1996, respectively. It is also interesting to observe that the estimated reserves additions for 1995 and 1996 exceed 1994 values by a wide margin, even though the pace of exploratory and development drilling in Alberta in those years was lower than in 1994 (Figures 3.5). A possible explanation for this apparent paradox is that producers shifted their efforts to targets in older and deeper formations which, generally speaking, have the potential for larger discoveries. This is supported by Figures 3.8 and 3.9, which show that the number of exploratory and development wells drilled in deeper horizons doubled in 1995, compared to 1994.

[13] To date, this analysis has been completed for Alberta data only, and reflects year-end 1995 reserves data, as published in the AEUB Statistical Series 96-18: *Reserves of crude oil, oil sands, gas, natural gas liquids and sulphur.*

Comparison of Estimate with Actual

F I G U R E 5 . 1

Comparison of NEB Statistical Estimation of Non-Associated Reserves vs Actual - Alberta



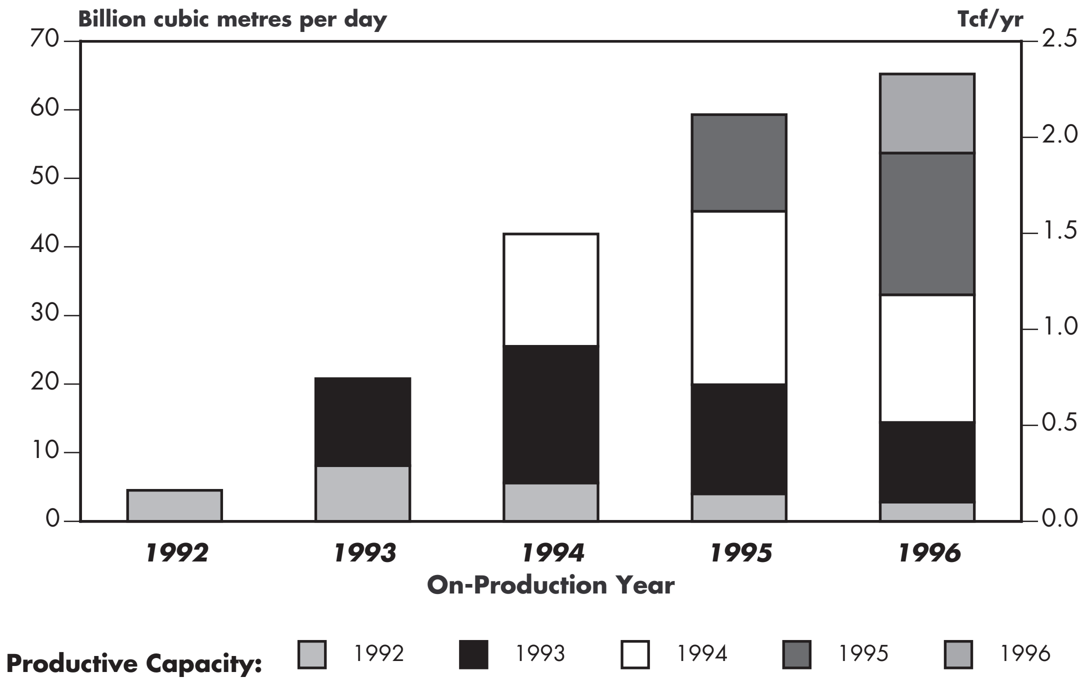
Note: Fully reported "Actual" reserves for 1995 and 1996 not available.

A comparison is made between the discovery volumes calculated using the Board's estimation methodology and the actual volume of reserves discovered annually, over the period 1980 to 1996 (Figure 5.1). A year by year comparison of reserves values indicated by this method with the actual reserves reported indicates a reasonably good match, overall.

A review of the regional and geological distribution of the model's results supports the observation of this move to deeper horizons. For example, for 1993, the model suggested 10.1 billion cubic metres (0.4 Tcf) of reserves would be found in zones below the Cretaceous; by 1995, this volume increased to 42.4 billion cubic metres (1.5 Tcf). From a regional perspective, the model suggests that the Central region, followed by the Northwest region, added the largest volumes of discovered reserves from exploratory drilling. With respect to discoveries from development drilling, the Central region predominates, followed by the East and Northwest regions.

FIGURE 5.2

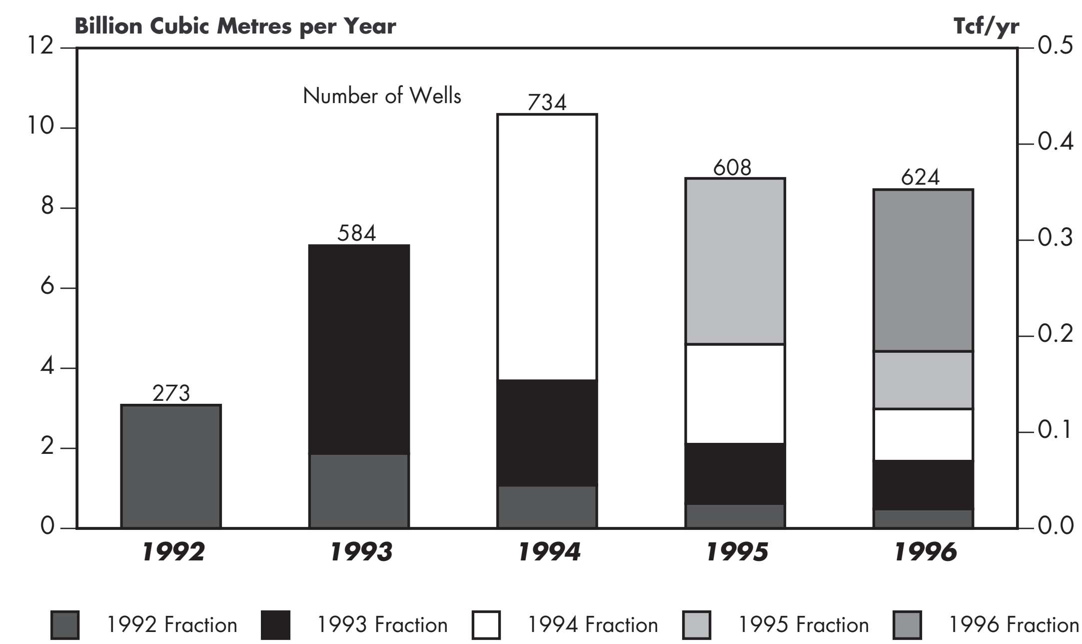
Estimated Productive Capacity Added By Well Connection 1992-1996 - Alberta



* 1996 values are estimates based on partial year data.

FIGURE 5.3

Estimated Productive Capacity Drilled But Not Connected 1992 -1996 - Alberta



* 1996 values are estimates based on partial year data.

5.2 Additions to Productive Capacity

The productive capacity of wells added over the period 1992 to 1996 played an important role in defining the impact of producers' response to changing market conditions. The contribution to productive capacity provided by this group of wells played a large part in shaping the overall supply picture.

To better understand the effect of recent drilling and well connection on productive capacity, the Board developed a statistical assessment methodology. This methodology is a well-based procedure that utilizes statistics on initial well performance, well decline profiles, the record of successful gas wells drilled over the period 1992 to 1996, and also considers the regional distribution of these parameters. Wells connected over this period, but drilled prior to 1992 are also included.

Figure 5.2 shows the estimated cumulative productive capacity added, for Alberta, in each year of the study period from all gas wells connected, sourced from wells drilled over this period, in addition to those drilled prior to 1992. Note that for a group of wells connected in any given year, the impact on capacity peaks in the following year, and subsequently declines thereafter. By year-end 1996, the contribution to total productive capacity from this group of wells amounted to 65.2 billion cubic metres per year (2.3 Tcf/yr), representing approximately 39 percent of current Alberta raw gas production. The largest percentage of productive capacity was added in Area 9, followed by Area 11 and Area 3 (See inset box). More details on the productive capacity estimation method and the results obtained can be found in Appendix III.

A certain portion of the productive capacity developed from wells drilled over the study period was surplus to demand. In order to estimate the magnitude of this surplus, a determination based on the number of unconnected wells for each of the 13 areas of Alberta was carried out. For any given year, the estimated surplus[14] is comprised of wells drilled in that year that were not connected for production, plus wells from previous years that remained unconnected. The product of the number of wells unconnected and the average initial well productivity yields an estimate of surplus productive capacity that existed at specific year-end points in time, for each year of the study period. The results of this exercise reveal that the surplus productive capacity developed over the study period reached a peak of 10.3 billion cubic metres per year (0.36 Tcf/yr) at year-end 1994. It should be noted that Figure 5.3 represents an estimate of the surplus productive capacity added by wells drilled over the study period, and does not represent the total surplus productive capacity that exists in the system.

[14] The assumption is made that any wells that remain unconnected for a period of 12 months from their finished drilling date are surplus.

Regional Breakdown of Productive Capacity Estimates

The regional distribution of the results obtained from the statistical estimates of productive capacity for the 13 NEB areas for Alberta are presented in Table 5.2.

TABLE 5.2

Regional Distribution of Productive Capacity Estimates

		Wells Drilled Pre-1992		Wells Drilled 1992-1996			
Area	Initial Well Rate 10^3m^3 /day	Wells	Capacity (10^6m^3/day)	Wells	Capacity (10^6m^3/day)	Total Capacity	Percentage of Total
1	8	699	5.8	3297	27	32.8	7.3%
2	18	540	10.7	869	17	27.7	6.1%
3	21	780	18.0	1251	29	47	10.4%
4	21	310	7.2	954	22	29.2	6.5%
5	55	190	11.5	400	24	35.5	7.9%
6	25	459	12.6	938	26	38.6	8.6%
7	25	342	9.4	655	18	27.4	6.1%
8	50	263	14.5	477	26	40.5	9.0%
9	60	263	17.3	611	40	57.3	12.7%
10	30	183	6.0	487	16	22	4.9%
11	55	296	17.9	539	33	50.9	11.3%
12	100	86	9.5	201	22	31.5	7.0%
13	200	19	2.8	36	8	10.8	2.4%
Totals		**4427**	**143.2**	**10713**	**309**	**451.2**	**100.0%**

The initial well production rates used are based on a review of average first-year production rates for all producing wells within each area, for wells put on production during the period 1992 to 1996. The steepening decline profiles associated with recently connected wells, as discussed in section 4.2.3, suggest that the majority of these wells are being produced at high utilization levels.

KEY OBSERVATIONS

Over the period 1992 to 1996, natural gas producers in the WCSB continued to adapt in an increasingly competitive, rapidly changing natural gas industry. They were also required to adjust to more volatile, generally lower prices and an overhang in deliverability. Following deregulation in the mid-1980s, the excess of productive capacity over demand that existed at the time was gradually reduced. At the same time, domestic and export demand increased, while lower gas prices tempered the pace of development of additional productive capacity. By 1992, deliverability and demand within the WCSB were in relatively close balance, setting the stage for the price and activity cycle that would occur over the mid-1992 to mid-1995 period. Listed below are our key observations on how producers responded to these changed circumstances:

- Increased competition with more volatile, generally lower gas prices forced producers to become more efficient, a move achieved in several ways:
    - by cost reduction through corporate restructuring, downsizing, optimization of property holdings, reduction in finding and development costs, and aggressively adopting new technology; and,
    - by a shift to a more short-term focus, as evidenced by the move to the "just in time" inventory management style.
- All of the activity indicators chosen (land sales, geophysics, drilling, well licensing) displayed a sharp, positive response to rising prices and a corresponding negative response to falling prices, albeit with a certain lag time between the price signal and the response.
- The underlying characteristics of supply appear to have changed. Producers are facing increasing numbers of well depletions, steepening production declines and decreasing average initial productivity per well.
- After 1994, a higher base level of activity was apparent. In 1995, there were 40 percent more gas wells drilled than in 1992, even though prices in those years were similar. This higher base level of drilling is thought to be due primarily to the changes in the underlying characteristics of supply, and the corresponding need to put increasingly more wells on production. The need to replace reserves and the need to maintain cash flow are important considerations as well.
- With respect to the level of gas drilling activities, the key observations are:
    - drilling was focused primarily on development, and on the shallow gas areas in 1993 and 1994. Over this time period, some 65 percent of wells drilled were development wells and, of these development wells, 60 percent were in shallow gas areas, and
    - in 1995, with the need to add additional deliverability not as urgent, overall drilling activity decreased, and a greater emphasis was placed on exploration and development drilling in deeper horizons.

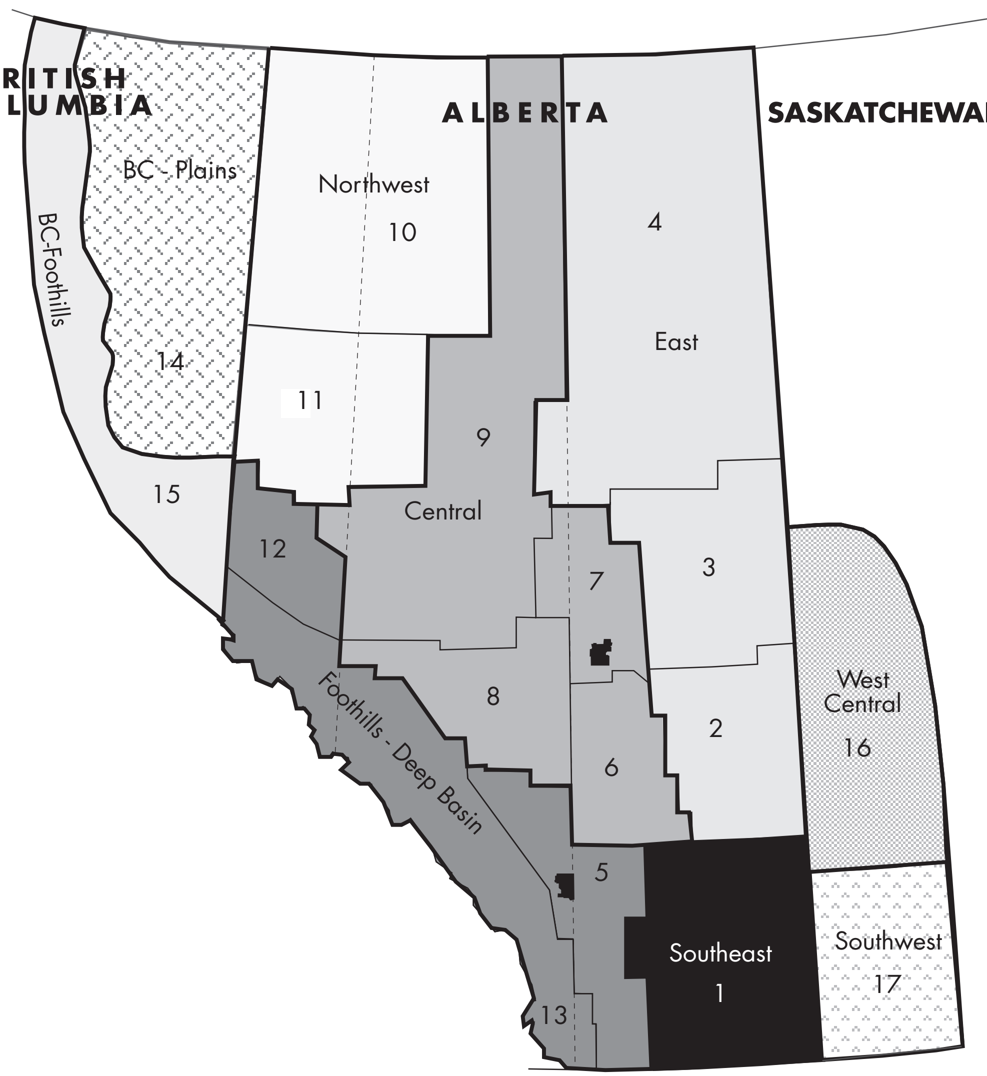
- There is an increasing reliance on the drilling and connection of new wells, with less reliance on older wells. From a pool perspective, the trend is to less reliance on older pools. In 1995, only 38 percent of new well connections were in pools greater than 20 years old, compared to 61 percent in 1985.
- The overall decline rate of Alberta's producing gas wells is increasing each passing year and stands at 18.1 per cent in 1995. This trend to steeper declines will likely continue, at least over the next 2 to 3 year period. This means that an increasing volume of additional deliverability must be connected, primarily through new wells, to account for this production decline, plus any increase in demand. It is estimated that some 3 500 to 4000 wells will have to be drilled and connected annually in the WCSB, over the 1997 to 1998 period, to meet this requirement. Although there was some evidence of a shift in the drilling effort to regions and zones of higher well productivity in 1995 and 1996, a more pronounced shift would likely be necessary to significantly reduce the level of required drilling in the near term.

3-D Seismic	Gathering seismic data from artificially-created sound waves. The data are enhanced by computer to form a three-dimensional representation of geological formations.
Associated Gas	Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir.
Deliverability	The amount of natural gas a well, field, pipeline, or distribution system can supply in a given period of time. Also, the practical out put from a storage reservoir. See "Productive Capacity".
Direct Sales	Gas purchase arrangements transacted directly between producers, brokers or marketers and end-users.
Electronic Trading	Refers to gas purchases and sales which take place via an electronic trading system. These systems allow gas to be bought and sold on an anonymous basis and provide for price discovery.
Established Reserves	Those reserves recoverable with current technology and under present and anticipated economic conditions. Includes reserves specifically proved by drilling, testing or production, plus that portion of contiguous recoverable reserves interpreted to exist with reasonable certainty based on geological, geophysical or similar information.
Field-gate	The point where gas is delivered from a gas producing field, after it has been gathered and processed, to a transmission system(eg. NATL). The field-gate is often used as a price reference point.
Initial Reserves	Reserves prior to the deduction of any production.
Netback Price	The per-unit price received by a gas producer from the sale of gas in end-use markets, less applicable costs. These typically include transportation and marketing fees.
Non-Associated Gas	Natural gas not in contact with crude oil in the reservoir.
Open Access	A basis for the provision of transportation services by inter-provincial, interstate and intra-provincial pipelines. The pipeline must provide service on a non-discriminatory basis to anyone requesting service at regulated rates.

Productive Capacity	A term used to describe the estimated rate at which natural gas can be produced from a well, pool or other entity, without consideration of demand, having regard to reservoir characteristics, producer netbacks, regulatory limitations, the feasibility of infill drilling and/or additional production facilities (e.g. compression), the existence of gathering and processing facilities, and potential losses due to plant turnarounds and operational problems.
Rate of Take	The initial rate at which gas will be produced from an entity such as a well, pool, field or area. It is usually expressed as a ratio. For example, a rate of take of 1:7000 means that 1 unit of production on a daily basis is obtained for each 7000 units of reserves for the entity under consideration.
Remaining Reserves	Initial reserves less cumulative production at the time of the esti mate.
Reserves Additions	Incremental changes to established reserves resulting from the discovery of new pools and/or revisions to reserves estimates for established pools.
Reserves to Production Ratio	Remaining reserves divided by annual production.
Reservoir	A reservoir (or pool) is a porous and permeable underground rock formation containing a natural accumulation of crude oil, natural gas and related substances that is confined by impermeable rock or water barriers, and is individual and separate from other reservoirs.
Reservoir Storage	Natural gas storage in a depleted reservoir which previously contained native hydrocarbons; the reservoir is developed with new or converted facilities including wells, pipelines and compression to inject and withdraw natural gas.
Solution Gas	Natural gas in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.
Take-or-Pay Clause	A contract provision whereby a purchaser agrees to pay for a specified volume of natural gas during a period whether or not the contract deliveries are taken.
Wellhead Price	The term wellhead price is used to specify a price reference or delivery point for natural gas. It is generally considered to be the price the producer receives after processing and gathering costs have been subtracted.

F I G U R E A 1 - 1

Western Canada Gas Areas and Regions



STRATIGRAPHIC ZONES USED IN REPORT

ZONE	HORIZON/AGE
A (MH,MR)	Milk River, Medicine Hat
B (U CRET)	Upper Cretaceous, except A
C (VIK, BI)	Viking, Bow Island
D (L CRET)	Lower Cretaceous, except C
E (JR-PENN)	Jurassic, Triassic, Permo-Penn.
F (MISS)	Missippian
G (DEV)	Devonian

Alberta Areas

AREA 1 Southeast Alberta, Medicine Hat Area

The area is gas prone, dominated by the Upper Cretaceous Milk River, 2WS and Medicine Hat Sandstone shallow gas pools.

AREA 2 Southeast Alberta, Provost Area

Gas in the area occurs in relatively shallow Viking (24%) and Mannville (69%) reservoirs, primarily channel sandstones.

AREA 3 East-Central Alberta, Lloydminster Area

Gas pools in the area are primarily Lower Cretaceous sandstones (86% of IMG). The remaining gas is in Devonian carbonates associated with the Devonian subcrop.

AREA 4 Northeast Alberta, Liege Area

Gas accumulations occur mainly in Cretaceous sandstones and Devonian. Carbonates associated with the Cretaceous onlap of the Devonian subcrop.

AREA 5 Southwest Alberta, Calgary Area

This area is located in the deeper part of the basin, lying in front of the Foothills belt. Gas occurs mainly in carbonate reservoirs of Mississippian (34%) and Devonian (33%) age.

AREA 6 Central Alberta, Red Deer Area

Central Alberta region along the Devonian reef trend. Major gas accumulations occur in Devonian and Mississippian carbonates and Lower Cretaceous sandstones.

AREA 7 Central Alberta, Edmonton Area

East Central Alberta area centered around Edmonton. Main gas accumulations are Viking and other Lower Cretaceous reservoirs (77%) and Devonian carbonates, of which a large portion is associated gas.

AREA 8 West-Central Alberta, Pembina Area

Area is dominated by the Pembina Field. Main gas accumulations occur in Mississippian shelf edge carbonates and Devonian reefs. Other reservoirs include upper Cretaceous Belly River and Cardium and other Lower Cretaceous sandstones.

AREA 9 West-Central Alberta, Kaybob Area

Main gas accumulations in this area are Devonian carbonates (50%) and Triassic, Jurassic and Cretaceous sandstones.

Area 10 Northwest Alberta, Rainbow Area

Gas occurs in Devonian platform carbonates and numerous small pools overlying Keg River pinnacles. The area is dominated by the relatively shallow Lower Cretaceous Bluesky gas accumulations.

AREA 11 West-Central Alberta, Peace River Arch

The area covers the Peace River Arch of Alberta. Plays are both stratigraphic and structural related to basement block faulting of the Peace River Arch.

AREA 12 West Alberta Deep Basin, Elmworth Area

Gas accumulations are primarily in Deep Basin Lower Cretaceous low permeability sandstones.

AREA 13 West Alberta, Foothills Area

This area comprises the foreland fold and thrust belt of Alberta. Gas accumulations occur primarily in Mississippian and Devonian thrust faulted structures.

British Columbia Areas

British Columbia Plains

The area covers the plains area of Northeast British Columbia, and is generally gas prone. Plays range in age from the Devonian to the Cretaceous, and are both stratigraphic and structural.

British Columbia Foothills

The area comprises the foothills belt of Northeast British Columbia, characterized by gentle folding, and thrust faulted structures. Main plays are of Triassic and Mississippian age, with some potential in the Cretaceous. The area is essentially all gas.

Saskatchewan Areas

Saskatchewan West Central Area

The area covers the west central part of Saskatchewan, centred around Lloydminster. The area is oil prone. Gas plays are mainly of Cretaceous age at relatively shallow depths.

Saskatchewan Southwest Area

The southwest area of Saskatchewan includes Jurassic oil pools and gas pools of Cretaceous age. The area is dominated by the areally large Hatton gas pool. The gas is shallow, characterized by low productivity wells.

STATISTICAL ESTIMATION OF RESERVES ADDITIONS FROM NEW DISCOVERIES

A flow chart outlining the methodology used for the statistical estimation of non-associated gas reserves is provided in Figure A2-1.

A review of the gas reserves discovered over the period 1980 to 1994 was carried out, utilizing year-end 1995 reserves estimates[15], as a first step in determining a relationship between the reserves found and the drilling effort expended over that time period. Reserves were allocated among the 13 NEB gas areas within Alberta and the seven NEB zones, or 91 individual "allocation units", based on the location and the finished drill date[16] of the discovery well, and based also on the pool formation code and reserves values, as assigned by the EUB.

An analysis of the successful exploratory and development gas wells drilled over the period 1980 to 1994 was carried out to determine the number of wells penetrating each of the allocation units. For each successful gas well drilled over this period, whether classified as exploration or development, a determination was made of the allocation units penetrated by that well. For example, a well drilled to the deepest of the seven NEB zones, the Devonian, would be considered a penetration event for each of the seven zones. The depth of penetration is determined by the total depth, or TD, of the well, and the zone assigned is the NEB zone that occurs at TD.[17] A determination is then made of the number of development discovery wells per development well penetration event and the number of exploratory discovery wells per exploratory well penetration event, for each individual allocation unit. Having determined the gas reserves per discovery well and the historical ratio of discovery wells to successful wells drilled, a prediction can be made of reserves that would be found within each allocation unit resulting from the drilling of a given number of successful exploratory and development gas wells. What this implies is that within each allocation unit, a given number of wells drilled will result in the discovery of a given number of gas pools and a corresponding volume of gas reserves, in the same ratio as exists on average for the 1980-1994 period.

In order to predict the gas reserves found by gas drilling in a particular year, the number of successful development and exploratory gas wells drilled for that year are allocated in the manner outlined above, resulting in an estimate of the number of discovery wells drilled within each

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15 As listed in AEUB Statistical Series 96-18: *Alberta's Reserves of crude oil,oil sands, gas, natural gas liquids and sulphur.*

16 In many cases, the rig release date was not available.

17 A check was made of the relationship between the NEB zone assigned on the basis of a well's TD and the deepest producing zone for that well, with the result that with very few exceptions, the well produced from the assigned NEB zone. Several wells actually have their TD in the Precambrian, and these wells were re-assigned to the NEB Devonian zone.

allocation unit. For each allocation unit, the number of discovery wells predicted is multiplied by the reserves assigned per discovery well for that allocation unit to arrive at a reserves estimate. The summation of the reserves for all of the allocation units then provides an estimate of the total gas reserves found by exploratory and development drilling, for the year being considered.

Based on this method of estimation, the non-associated gas reserves found in the years 1994, 1995 and 1996 are 73.5, 108.0 and 105.3 billion cubic metres (2.6, 3.8 and 3.7 Tcf) respectively, as shown in Table A2-11.

These estimates are based on the reserves discovered over the period 1980 to 1994. Taking into account the 14 year age-range considered, it was assumed that these reserves are substantially appreciated. Given that gas reserves appreciation factors are the subject of some debate among natural gas industry analysts, readers may wish to apply their own assumptions regarding the level of appreciation.

FIGURE A2-1

Flow Chart for Statistical Estimation of Reserves from New Discoveries - Alberta

The flow chart shown below is provided to assist the reader in following the methodology used to arrive at our statistical estimates of reserves discovered by recent exploratory and development gas wells drilling. The chart describes the methodology for exploratory gas wells, but the methodology for development wells is identical. Note that all values determined are based on distributions within the 13 NEB gas areas and within the 7 NEB zones defined, all for Alberta.

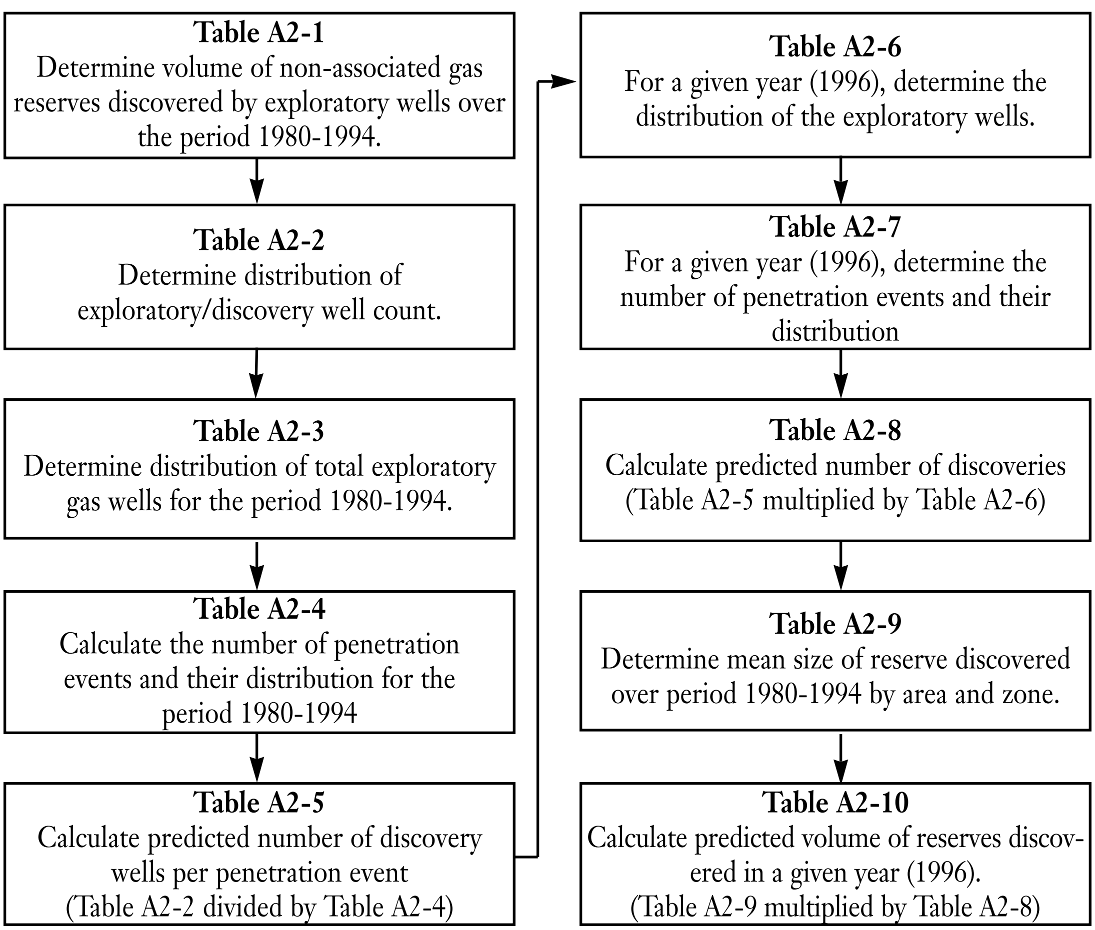


TABLE A2-1

Distribution of Non-Associated Gas Reserves Discovered by Exploratory Wells 1980-1994, by Area and by Zone (Billion Cubic Feet)

AREA/ZONE	A	B	C	D	E	F	G	Total
1	37.0	47.0	367.8	1217.5	42.9	45.1	89.7	1847.0
2	0.9	31.6	83.2	942.5	0.0	27.4	13.9	1099.5
3	0.2	4.6	50.0	867.9	0.0	0.0	59.0	981.8
4	0.0	0.0	4.9	583.4	0.0	0.0	37.7	626.0
5	4.5	105.1	145.8	410.3	26.5	205.1	739.3	1636.7
6	0.0	262.3	87.8	997.9	0.0	78.7	58.7	1485.4
7	1.2	4.7	32.3	558.3	0.0	0.0	103.6	700.2
8	8.9	278.8	68.0	616.6	314.8	232.3	272.0	1791.4
9	2.6	154.1	43.5	666.0	136.9	39.6	440.7	1483.4
10	0.0	0.0	0.0	77.3	0.0	50.1	386.8	514.2
11	0.0	14.8	0.0	438.8	590.4	486.8	179.6	1710.3
12	0.0	122.1	0.0	773.2	257.3	8.7	58.1	1219.4
13	0.0	32.9	0.0	34.9	39.4	790.2	107.6	1005.1
Total	**55.3**	**1058.2**	**883.5**	**8184.6**	**1408.2**	**1963.9**	**2546.6**	**16100.3**

TABLE A2-2

Distribution of Exploratory Discovery Wells 1980-1994, by Area and by Zone

AREA/ZONE	A	B	C	D	E	F	G	Total
1	22	77	355	612	30	32	52	1180
2	2	43	139	953	0	22	14	1173
3	1	7	141	1110	0	0	30	1289
4	1	0	6	495	0	0	25	527
5	6	43	50	150	8	32	11	300
6	0	201	111	589	0	43	38	982
7	2	6	74	521	0	0	46	649
8	6	129	43	221	89	61	35	584
9	1	36	26	202	43	11	81	400
10	0	0	0	9	0	20	280	309
11	0	16	0	212	195	86	49	558
12	0	40	0	158	52	1	4	255
13	0	4	0	6	3	23	7	43
Total	**41**	**602**	**945**	**5238**	**420**	**331**	**672**	**8249**

TABLE A2-3

Distribution of all Exploratory Gas Wells 1980-1994, by Area and by Zone

AREA/ZONE	A	B	C	D	E	F	G	U	Total
1	276	113	454	635	28	114	31	4	1656
2	34	82	240	810	0	47	90	4	1308
3	1	5	123	1097	0	0	198	0	1425
4	1	0	9	535	0	2	122	1	670
5	29	67	89	190	20	64	41	3	503
6	2	325	177	661	0	72	68	6	1313
7	7	9	73	523	0	6	103	1	722
8	0	128	51	312	122	108	51	2	774
9	1	71	30	344	118	57	98	1	721
10	1	0	0	50	15	52	161	0	280
11	4	34	0	227	328	140	47	4	784
12	0	49	0	244	62	2	5	2	364
13	0	6	3	6	4	49	12	2	82
Total	**356**	**889**	**1249**	**5634**	**697**	**713**	**1027**	**30**	**10602**

TABLE A2-4

Distribution of Penetration Events For Exploratory Wells 1980-1994, by Area and by Zone

AREA/ZONE	A	B	C	D	E	F	G	U
1	1656	1380	1267	813	178	150	36	5
2	1308	1274	1192	952	142	142	95	5
3	1425	1424	1419	1296	199	199	19	1
4	670	669	669	660	125	125	123	1
5	503	474	407	318	128	108	44	3
6	1313	1311	986	809	148	148	76	8
7	722	715	706	633	110	110	104	1
8	774	774	646	595	283	161	53	2
9	721	720	649	619	275	157	100	2
10	280	279	279	279	229	214	162	1
11	784	780	746	746	519	191	51	4
12	364	364	315	315	71	9	7	2
13	82	82	76	73	67	63	14	2
Total	**10602**	**10246**	**9357**	**8108**	**2474**	**1777**	**1064**	**37**

TABLE A2-5

Distribution of Predicted Number of Discovery Wells Per Penetration Event 1980-1994, by Area and by Zone

AREA/ZONE	A	B	C	D	E	F	G
1	0.0133	0.0558	0.2802	0.7528	0.1685	0.2133	1.4444
2	0.0015	0.0338	0.1166	1.0011	0.0000	0.1549	0.1474
3	0.0007	0.0049	0.0994	0.8565	0.0000	0.0000	0.1508
4	0.0015	0.0000	0.0090	0.7500	0.0000	0.0000	0.2033
5	0.0119	0.0907	0.1229	0.4717	0.0625	0.2963	0.2500
6	0.0000	0.1533	0.1126	0.7281	0.0000	0.2905	0.5000
7	0.0028	0.0084	0.1048	0.8231	0.0000	0.0000	0.4423
8	0.0078	0.1667	0.0666	0.3714	0.3145	0.3789	0.6604
9	0.0014	0.0500	0.0401	0.3263	0.1564	0.0701	0.8100
10	0.0000	0.0000	0.0000	0.0323	0.0000	0.0935	1.7284
11	0.0000	0.0205	0.0000	0.2842	0.3757	0.4503	0.9608
12	0.0000	0.1099	0.0000	0.5016	0.7324	0.1111	0.5714
13	0.0000	0.0488	0.0000	0.0822	0.0448	0.3651	0.5000

TABLE A2-6

Distribution of 1996 Successful Gas Well Count, by Area and by Zone

AREA/ZONE	A	B	C	D	E	F	G	Total
1	7	4	1	39	2	22	8	83
2	0	9	12	32	0	0	12	65
3	0	0	0	33	0	0	19	52
4	0	1	0	44	0	0	51	96
5	32	6	5	11	5	21	5	85
6	2	16	-1	25	0	6	13	61
7	0	0	0	39	0	2	9	50
8	0	12	0	8	10	40	6	76
9	0	2	4	36	30	17	38	127
10	0	4	0	13	7	9	24	57
11	0	5	0	8	46	22	9	90
12	0	10	0	6	4	0	2	22
13	0	4	0	2	0	2	3	11
Total	**41**	**73**	**21**	**296**	**104**	**141**	**199**	**875**

TABLE A2-7

Distribution of Exploratory Penetration for 1996, by Area and by Zone

AREA/ZONE	A	B	C	D	E	F	G
1	83	76	72	71	32	30	8
2	65	65	56	44	12	12	12
3	52	52	52	52	19	19	19
4	96	96	95	95	51	51	51
5	85	53	47	42	31	26	5
6	61	59	43	44	19	19	13
7	50	50	50	50	11	11	9
8	76	76	64	64	56	46	6
9	127	127	125	121	85	55	38
10	57	57	53	53	40	33	24
11	90	90	85	85	77	31	9
12	22	22	12	12	6	2	2
13	11	11	7	7	5	5	3
Total	**875**	**834**	**761**	**740**	**444**	**340**	**199**

TABLE A2-8

Distribution of Predicted Number of Discoveries for 1996, by Area and by Zone

AREA/ZONE	A	B	C	D	E	F	G	Total
1	1	4	20	53	5	6	12	103
2	0	2	7	44	0	2	2	58
3	0	0	5	45	0	0	3	56
4	0	0	1	71	0	0	10	87
5	1	5	6	20	2	8	1	47
6	0	9	5	32	0	6	7	64
7	0	0	5	41	0	0	4	58
8	1	13	4	24	18	17	4	88
9	0	6	5	39	13	4	31	108
10	0	0	0	2	0	3	41	56
11	0	2	0	24	29	14	9	89
12	0	2	0	6	4	0	1	26
13	0	1	0	1	0	2	2	18
Total	**3**	**45**	**58**	**402**	**72**	**62**	**126**	**858**

TABLE A2-9

Distribution of Mean Initial Marketable Gas Reserves 1980-1994, by Area and by Zone (Billion Cubic Feet)

AREA/ZONE	A	B	C	D	E	F	G
1	1.68	0.61	1.04	1.99	1.43	1.41	1.72
2	0.43	0.74	0.60	0.99	0.00	1.24	0.99
3	0.18	0.66	0.35	0.78	0.00	0.00	1.97
4	0.04	0.00	0.82	1.18	0.00	0.00	1.51
5	0.76	2.44	2.92	2.74	3.32	6.41	67.21
6	0.00	2.87	1.61	6.21	0.00	1.33	1.42
7	0.60	0.79	0.44	1.07	0.00	0.00	2.25
8	1.17	2.16	1.58	2.79	3.54	3.81	7.77
9	2.59	4.28	1.67	3.30	3.18	3.60	5.44
10	0.00	0.00	0.00	2.00	0.00	2.50	1.38
11	0.00	0.93	0.00	2.07	3.03	5.66	3.67
12	0.00	3.05	0.00	4.89	4.95	8.66	14.52
13	0.00	8.23	0.00	5.82	13.14	34.36	15.37

TABLE A2-10

Distribution of Predicted Reserves Discovered for 1996, by Area and by Zone (Billion Cubic Feet)

AREA/ZONE	A	B	C	D	E	F	G	Total
1	1.68	2.44	20.80	105.47	7.15	8.46	20.64	167.60
2	0.00	1.48	4.20	43.56	0.00	2.48	1.98	55.70
3	0.00	0.00	1.75	35.10	0.00	0.00	5.91	45.80
4	0.00	0.00	0.82	83.78	0.00	0.00	15.10	103.70
5	0.76	12.20	17.52	54.80	6.64	51.28	67.21	215.40
6	0.00	25.83	8.05	198.72	0.00	7.98	9.94	256.50
7	0.00	0.00	2.20	43.87	0.00	0.00	9.00	62.10
8	1.17	28.08	6.32	66.96	63.72	64.77	31.08	270.10
9	0.00	25.68	8.35	128.70	41.34	14.40	168.64	396.10
10	0.00	0.00	0.00	4.00	0.00	7.50	56.58	78.10
11	0.00	1.86	0.00	49.68	87.87	79.24	33.03	262.70
12	0.00	6.10	0.00	29.34	19.80	0.00	14.52	81.80
13	0.00	8.23	0.00	5.82	0.00	68.72	30.74	126.50
Total	**3.61**	**111.90**	**70.01**	**849.80**	**226.52**	**304.83**	**464.37**	**2031.00**

TABLE A2-11

Comparison of NEB Statistical Estimates of Non-Associated Gas Discoveries vs Actual 1980-1996, Alberta

Year	Development	Exploratory	Total of NEB Estimates		Actual Discovered Reserves	
	(10^9m^3)	(10^9m^3)	(10^9m^3)	(Tcf)	(10^9m^3)	(Tcf)
1980	61.8	26.4	88.1	3.11	89.5	3.16
1981	46.6	21.6	68.2	2.41	71.6	2.53
1982	24.5	15.3	39.8	1.40	33.7	1.19
1983	14.5	10.7	25.2	8.89	43.3	1.53
1984	22.6	12.5	35.2	1.24	32.5	1.15
1985	20.7	21.3	41.9	1.48	34.2	1.21
1986	15.2	25.3	40.5	1.43	45.9	1.62
1987	15.6	28.0	43.6	1.54	30.3	1.07
1988	21.4	38.6	60.0	2.11	50.3	1.78
1989	14.4	39.3	53.8	1.89	37.6	1.33
1990	12.9	38.6	51.5	1.82	44.4	1.57
1991	8.5	22.8	31.3	1.11	36.6	1.29
1992	5.2	14.0	19.2	0.68	21.8	0.77
1993	19.7	27.1	46.8	1.65	40.1	1.42
1994	31.1	42.3	73.5	2.59	65.0	2.29
1995	39.8	64.4	108.0	3.81	5.6*	0.20*
1996	47.8	57.5	105.3	3.72	n/a	n/a
Total	**422.3**	**509.5**	**931.9**	**40.88**	**676.8**	**23.91**

* Only partial year data reported to date.

ESTIMATES OF PRODUCTIVE CAPACITY FROM RECENT DRILLING AND WELL CONNECTION

A review of well productivity was carried out using individual well raw gas production statistics for all Alberta producing gas wells over the period 1992 to 1996. This data was allocated among the 13 NEB gas areas within Alberta, based on the well locations, and was also allocated by year of production.

Table A3-1 provides the maximum and average first year producing rates by area over this time period. In order to determine the average maximum rate value for a given area and a given year, the highest monthly active-day production rates for all individual wells were averaged. The average mean rates were calculated in the same manner. Only wells with at least 3 months of continuous production were included, to eliminate wells that may have had short periods of test production, but were never put on full production.

TABLE A3-1

Average First-Year Producing Rates, By Area - Alberta

Area	Average of Mean	Average of Maximum
1	8	13
2	18	27
3	21	32
4	21	37
5	55	75
6	25	35
7	25	40
8	50	70
9	60	90
10	30	45
11	55	80
12	100	150
13	200	260

The maximum well producing rates as defined here represent the case where wells would be able to produce at their peak capability throughout the year. Since, on the whole, wells cannot sustain peak levels of production without some down time for maintenance and for other logistical reasons, estimates of productive capacity based on the maximum rates would be overly optimistic.

Conversely, estimates of productive capacity based on the average well rates would be somewhat conservative. However, in the 1993 to 1996 period, most wells were producing at near maximum capability, with only a small portion producing below full utilization levels. For the purpose of the "statistical estimates" of productive capacity, the Board has adopted initial productivity rates for each area that are equal to the mean rates shown in Table A3-1. It should be noted that the estimation methodology takes into account the average production profiles within each of the 13 areas, to determine the volumes to be carried forward each successive year.

For this study, the productive capacity estimation method considered the contribution to capacity for three different cases. First, the potential productive capacity added by all successful gas wells drilled over the study period is considered. The assumption is made that all wells were connected in the year they were drilled, and the cumulative potential productive capacity is determined on an annual basis (Table A3-2). Second, the contribution made to productive capacity by all wells actually connected over the study period was determined (Table A3-3). This includes wells sourced from the pre-1992 inventory. Third, an estimation was made of the potential productive capacity from those wells drilled over the study period but not connected. The assumption is made that this volume is surplus to producers' requirements. Wells included in this "unconnected" category are those that are not connected within one year of their finished drill date. For any given year, the estimated surplus consists of wells drilled in that year that remain unconnected, according to the above definition, plus any wells from previous years that remain unconnected. The results of this exercise yield year-by-year estimates of the surplus productive capacity that existed at specific year-end points in time (Table A3-4).

TABLE A3-2

Estimated Productive Capacity from Wells Drilled 1992-1996 - Alberta

Initial Well Producing Rates by Area (10^3m^3/day)

Area	1	2	3	4	5	6	7	8	9	10	11	12	13
	8	18	21	21	55	25	25	50	60	30	55	100	200

Number of Wells Drilled

Area	1	2	3	4	5	6	7	8	9	10	11	12	13	Total
1992	201	68	122	52	15	50	82	32	17	12	41	16	6	**714**
1993	999	145	187	112	93	181	163	64	103	45	143	23	4	**2262**
1994	1331	267	353	237	113	257	141	161	208	126	168	50	4	**3416**
1995	511	259	343	327	135	306	168	147	209	219	120	73	11	**3135**
1996*	793	175	443	353	168	268	207	198	274	123	175	52	19	**3248**

* Well count for 1996 is an estimate based on partial year data.

Estimated Potential Cumulative Productive Capacity 1992-1996 ** (10^3m^3/day)

Area	1	2	3	4	5	6	7	8	9	10	11	12	13	Total 10^9m^3/yr	Total Tcf/yr
1992	603	490	1025	437	330	500	820	640	408	144	902	640	480	**2.7**	**0.1**
1993	5146	2292	3953	2222	3515	3301	3369	3040	4113	1013	6017	2369	1532	**15.3**	**0.5**
1994	10769	4685	7456	5139	8270	6601	4689	7265	10658	2919	11980	4628	2138	**31.8**	**1.1**
1995	12637	7138	11297	9903	13662	10118	5630	12584	18192	6951	16079	8632	4019	**49.9**	**1.8**
1996	11930	7634	13623	13926	18088	11340	6026	16437	22994	9051	18013	10368	6507	**60.6**	**2.1**

** Assumes all wells drilled are connected, in year drilled.

TABLE A3-3

Estimated Productive Capacity from Wells Connected 1992-1996 - Alberta

Initial Well Producing Rates by Area (10^3m^3/day)

Area	1	2	3	4	5	6	7	8	9	10	11	12	13
	8	18	21	21	55	25	25	50	60	30	55	100	200

Number of Wells Connected

Area	1	2	3	4	5	6	7	8	9	10	11	12	13	Total
1992	267	101	197	67	42	129	138	52	36	26	59	25	7	**1146**
1993	894	246	260	145	85	246	231	116	114	50	143	43	4	**2577**
1994	1525	406	587	296	181	370	232	200	225	153	260	68	5	**4508**
1995	760	254	451	269	121	275	190	153	194	174	180	51	14	**3086**
1996	866	250	442	291	131	293	205	157	200	180	191	55	13	**3275**

Estimated Potential Cumulative Productive Capacity 1992-1996 (10^3m^3/day)

Area	1	2	3	4	5	6	7	8	9	10	11	12	13	Total	
														10^9m^3/yr	Tcf/yr
1992	801	727	1655	563	924	1290	1380	1040	864	312	1298	1000	560	**4.5**	**0.2**
1993	5049	3708	5899	2871	4535	5479	5074	5270	5274	1410	6760	4090	1714	**20.9**	**0.7**
1994	10926	7489	11443	6558	10336	9791	7123	11149	12151	3603	14533	7411	2375	**41.9**	**1.5**
1995	13837	9832	16409	10717	15926	12434	7673	16344	18363	6686	20647	9727	3860	**59.3**	**2.1**
1996	13408	9879	17675	13376	18546	12634	7177	18532	20693	8655	22464	10201	5498	**65.2**	**2.3**

TABLE A3-4

Estimated Potential Productive Capacity from Wells Unconnected, by Year, 1992-1996 - Alberta

Initial Well Producing Rates by Area (10^3m^3/day)

Area	1	2	3	4	5	6	7	8	9	10	11	12	13
	8	18	21	21	55	25	25	50	60	30	55	100	200

Number of Wells Unconnected at Year-end

Area	1	2	3	4	5	6	7	8	9	10	11	12	13	Total
1992	44	32	61	31	8	20	27	13	5	2	24	3	3	273
1993	80	53	70	73	26	36	47	29	33	13	77	5	5	547
1994	94	63	101	67	33	56	48	61	65	37	82	18	8	733
1995	62	40	58	124	20	46	21	47	67	48	47	18	9	607
1996*	108	41	72	130	18	43	15	45	57	21	53	16	10	629

* Well count for 1996 is an estimate based on partial year data.

Estimated Potential Productive Capacity Drilled 1992-1996, Remaining Unconnected, By Year (10^3m^3/day)

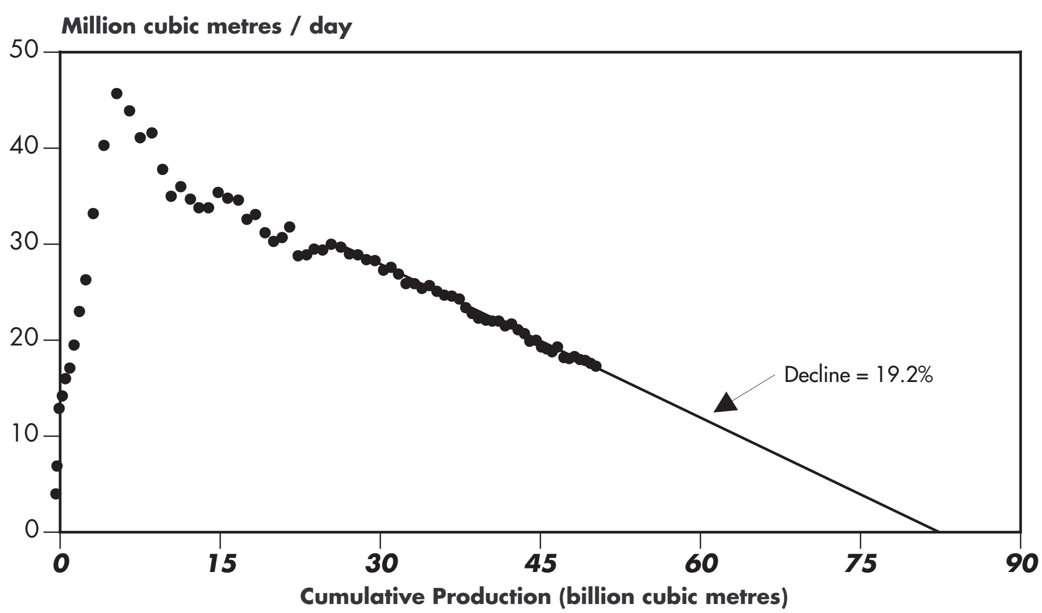
Area	1	2	3	4	5	6	7	8	9	10	11	12	13	Total	
														10^9m^3/yr	**Tcf/yr**
1992	132	231	514 2	61	177	201	271	261	120	24	530	120	241	**3.08**	**0.11**
1993	241	383	590	615	574	361	472	582	795	157	1700	201	402	**7.07**	**0.25**
1994	283	455	852	565	729	562	482	1225	1566	446	1811	723	642	**10.34**	**0.36**
1995	187	289	489	1046	442	462	211	944	1614	578	1038	723	723	**8.74**	**0.31**
1996	325	296	607	1096	397	432	151	903	1373	253	1170	642	803	**8.45**	**0.30**

ANALYSIS OF PRODUCTION DECLINE RATES

Figure A4-1 shown below is a plot of cumulative production versus the active-day production rate for all non-associated gas wells that first came on production in 1990. Similar plots were constructed for each year 1985 through 1995, as well as one plot for pre-1985 wells. The decline rates determined from these plots form the basis for the production decline rates shown in Table 4.1.

F I G U R E A 4 - 1

Active-Day Rate vs Cumulative Production for Wells First On in 1990 - Alberta



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