National Energy Board

Office national de l'énergie

Short-term **Natural Gas** Deliverability

from the

Western **C**anada **S**edimentary **B**asin

2000 - 2002

An **ENERGY MARKET ASSESSMENT** • December 2000

National Energy Board

Office national de l'énergie

Short-term **Natural Gas** Deliverability *from the* **W**estern **C**anada **S**edimentary **B**asin *2000-2002*

An **ENERGY MARKET ASSESSMENT** • December 2000

Cat. No. NE23-82/2000E
ISBN 0-662-29501-3

This report is published separately in both official languages.

Copies are available on request from:
Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-Mail: orders@neb.gc.ca
Fax: (403) 292-5503
Phone: (403) 299-3562
1-800-899-1265

For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

Nº de cat. NE23-82/2000F
ISBN 0-662-85167-6

Ce rapport est publié séparément dans les deux langues officielles.

Exemplaires disponibles sur demande auprès du:
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta), T2P 0X8
Courrier élctronique : orders@neb.gc.ca
Télécopieur : (403) 292-5503
Téléphone : (403) 299-3562
1-800-899-1265

En personne, au bureau de l'Office:
Bibliothèque
Rez-de-chaussée

Imprimé au Canada

Figures

Tables

Acronyms

B.C.	British Columbia
EMA	Energy Market Assessment
NEB	National Energy Board
NGMA	Natural Gas Market Assessment
NE	North East
NW	North West
PSAC	Petroleum Services Association of Canada
SE	South East
SW	South West
WC	West-Central
WCSB	Western Canada Sedimentary Basin

Units

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

m^3/d	=	cubic metres per day
Mcf	=	thousand cubic feet
MMcf	=	million cubic feet
Bcf	=	billion cubic feet
Tcf	=	trillion cubic feet
Mcf/d	=	thousand cubic feet per day
MMcf/d	=	million cubic feet per day
Bcf/d	=	billion cubic feet per day
Gj	=	Gigajoules (10^9 joules)

FOREWORD

The National Energy Board (the Board or NEB), as a part of its regulatory mandate, continually monitors the Canadian supply of all energy commodities (including electricity, oil, natural gas and their by-products) and the demand for Canadian energy commodities in both the domestic and export markets.

The NEB adopted the Market-Based Procedure (MBP) in 1987 for assessing applications for long-term natural gas export licences. As a part of the MBP, the NEB is committed to publish its *Canadian Energy Supply and Demand* reports[1] as well as a series of *Natural Gas Market Assessment* (NGMA) reports. As a result of the increasing level of integration within energy markets, the NEB has implemented a program of Energy Market Assessments (EMA) to provide analyses of the major energy commodities on either an individual or integrated commodity basis. The EMA program includes what were previously known as NGMAs, as well as the Canadian Energy Supply and Demand reports. For the natural gas market in particular, EMAs are focussed on current issues specifically related to the functioning of the market and characteristics of the resource base.

This EMA report, titled *Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin, 2000 -2002*, examines the factors which affect gas supply in the short term and presents an outlook for deliverability to the year 2002. The main objective of this report is to advance the understanding of the short-term gas supply situation by examining recent trends in the production characteristics of the Western Canada Sedimentary Basin (WCSB) and applying these trends to provide an outlook for short-term deliverability from the WCSB. Further, this report is an update to the Board's September 1999 EMA on short-term deliverability.

During the preparation of this report, a series of meetings and discussions were conducted with natural gas producers, pipeline companies, industry associations and government agencies. The NEB appreciates the information and comments it received.

[1] *Canadian Energy Supply and Demand to 2025*, published in June 1999, is the most recent of these reports.

OVERVIEW

During the past few years, growth in North American gas supply has lagged growth in gas demand. This has led to a tightening of the continental gas supply situation and generated concerns regarding the robustness of the North American gas supply. Considering these recent developments and the importance of the Western Canada Sedimentary Basin (WCSB) in meeting Canadian gas requirements, the NEB is updating its forecast of short-term deliverability from the WCSB.

The WCSB includes most of Alberta and significant portions of British Columbia and Saskatchewan as well as parts of Manitoba and the Northwest Territories. Virtually all Canadian natural gas demand is met by production from the WCSB. In addition, the WCSB meets almost 15 percent of gas consumption in the United States. Natural gas production from the WCSB averaged about 465 million m3/d (16.4 Bcf/d) in 1999, a two percent increase over the previous year.

This Energy Market Assessment (EMA) reviews the producing characteristics of natural gas wells from 1990 to 1999. These producing characteristics are then combined with a forecast of drilling activity in order to generate a forecast of natural gas deliverability from 2000 to 2002. Future natural gas deliverability can be simply expressed as the sum of future production from existing wells and production from new wells.

Current Situation

Once a gas well has been drilled and commences production, the production rate will normally decline as reserves are being depleted. Over the past few years, the decline rates from recently drilled wells have been higher than from older wells, reaching as high as 40 percent per year. The overall decline rate from the WCSB, however, is closer to about 20 percent per year, reflecting a significant amount of production from wells drilled many years ago with lower decline rates. Based on this 20 percent decline rate, the NEB projects that production from existing wells in the WCSB will decline by about 85 million m3/d (3 Bcf/d) each year. This amount of production is equivalent to natural gas consumption in Alberta, British Columbia and Saskatchewan in 1999.

Production from new wells can be projected by extrapolating trends in production characteristics of recent wells and forecasting the number of wells that will be drilled in the future. The NEB analyzed historical production data and determined a production profile, consisting of values for initial well productivity and decline rate, for a typical new well.

Two key trends were identified. First, recently drilled wells start producing at lower rates than wells drilled more than five years ago. The second trend indicates that production from these wells declines more quickly than from older wells.

Assuming that recent trends in production characteristics will continue over the short term, it is fair to say that future wells will generally be less productive than wells drilled a few years ago. Consequently, the producing industry will need to drill more wells to offset production declines from existing gas wells in order to maintain, or increase, overall deliverability from the WCSB.

Forecasts

Based on discussions with the gas producing industry, forecasts available from drilling associations and its own analyses, the Board expects that about 8,100 gas wells will be drilled in 2000, followed by 8,700 gas wells in 2001 and 8,900 gas wells in 2002. The Board also expects that there will be a shift in drilling activity to the more prolific areas located in the western and northern parts of the WCSB. This increase in drilling activity, when combined with the expected characteristics of new wells and the projected deliverability from existing wells, results in total deliverability increasing from 465 million m3/d (16.4 Bcf/d) in 1999 to 495 million m3/d (17.5 Bcf/d) in 2002.

However, the NEB recognizes that there are a number of uncertainties that will affect deliverability - the major factor being the level of drilling activity. For example, should drilling activity reach 9,800 gas wells, then deliverability could increase to 530 million m3/d (18.8 Bcf/d) by 2002. On the other hand, deliverability will remain flat if drilling activity is only maintained at 8,100 gas wells per year.

INTRODUCTION

In 1999, natural gas production from the Western Canada Sedimentary Basin (WCSB) totalled approximately 170 million m^3 (6.0 Tcf) or an average production rate of 465 million m^3/d (16.4 Bcf/d), causing the WCSB to rank as one of North America's most productive basins. Canadian natural gas demand is almost entirely satisfied through production from the WCSB[1]. As well, Ontario will be able to import significant volumes from the U.S. when the Vector Pipeline commences service in late 2000. Indeed, the WCSB meets one-quarter of total North American demand[2], reaching markets in the U.S. Midwest, Northeast, Pacific Northwest and California as well as Canada.

During the last few years, growth in North American natural gas supply has lagged growth in demand. This is primarily attributable to the low oil price environment of 1997/98, which reduced cash flow for the producing industry. In turn drilling activity decreased throughout North America. With the increase of oil prices in 1999 and the accompanying increases in industry cash flow, Canadian producers increased drilling to a record 6,300 gas wells. Despite this strong level of activity, however, natural gas production from the WCSB increased only marginally, by some 11 million m^3/d (0.4 Bcf/d) or about two percent. This sluggish increase in natural gas production has created some concern about the robustness of supply from the WCSB, especially if the coming winter in Canada is colder than the past few years.

In its EMA on short-term natural gas deliverability published in September 1999, the NEB expected an increase in production of about 14 million m^3/d (0.5 Bcf/d) during 1999. Moreover, the NEB stated that it had anticipated that the increase in production could be realized by drilling about 5,000 gas wells. These expectations were predicated on the assumption that new wells would have the same producing characteristics as wells for which the most recent data were available. More up-to-date data indicate that this has not been the case.

In this EMA, the Board has updated its assessment of short-term deliverability based on its continuous examination of trends in the producing characteristics of the WCSB. In doing so, the NEB has not attempted to match supply with demand as in its previous report; instead, the NEB has determined the level of gas supply that would result from an active drilling program. In its analyses, the Board has focussed strictly on trends in annual deliverability and has not attempted to account for seasonal fluctuations in deliverability, including those resulting from the use of gas storage.

1 It is expected that deliveries of gas from Sable Island will begin to reach consumers in Nova Scotia and New Brunswick in 2000.

2 In this context, North America includes Canada and the lower 48 states of the United States.

METHODOLOGY AND ASSUMPTIONS

2.1 Future Deliverability

Future natural gas deliverability is a function of initial deliverability from existing natural gas wells, normal decline in deliverability from existing wells as depletion occurs, the number of new gas wells drilled and the average deliverability of new gas wells. As a result, future deliverability can be expressed, in general terms, by the following equation:

future deliverability = [deliverability from existing wells - decline] + [productivity of a typical new well multiplied by number of new wells]

In making its determination of future deliverability the Board has used this framework.

2.2 Key Assumptions

In projecting deliverability, a number of assumptions have been made to account for the complexity of the analyses and the dynamic of the natural gas producing sector. These include:

- decline rates for currently connected wells do not change significantly;

  The average decline rate for existing wells is assumed to be constant over the forecast period. However, this is not considered to be a critical assumption because a change in decline rate would require several years before it significantly impacts overall deliverability.

- the producing characteristics for future wells can be extrapolated from the performance of recently drilled wells;

  The deliverability forecast relies on the expected production profiles of typical wells, which, in turn, are based on the performance of recently drilled wells. Any differences between the expected production profiles and those of wells actually placed on production will directly impact deliverability. In a deliverability forecast, any differences in the ability of wells to produce must be compensated for either by increasing or decreasing the number of wells.

- sufficient prospects are available to support the number of wells included in the forecasts;

  The amount of reserves being discovered in a basin normally decreases over time, as cumulative discoveries approach the ultimate potential of the basin. The decrease in the amount of reserves added normally occurs gradually and a drastic shift in reserves additions would be considered abnormal over the three year time span of this forecast. Various studies on ultimate potential also show that smaller pools are normally discovered as a basin matures and most basins contain many small pools. This forecast, is based on the assumption that

sufficient prospects are available to support the number of wells included in the forecasts. Discussions with producers support this assumption in the short-term.

- facilities such as gas plants or gathering lines will be added as required;

  To develop new gas deliverability, producers may have to increase drilling in remote areas of the WCSB. Some of these areas may not have as well-developed infrastructure as other regions of the basin, leading to possible delays in connecting new gas wells. In the short-term, it is assumed that facilities such as gas plants would be available.

- wells are available for production as soon as they are drilled;

  The time from when a well is completed to when it is placed on production tends to be very short in the shallow areas of the WCSB where the majority of wells are currently being drilled. The impact on deliverability from this time lag for the shallow areas would be minimal. Additional time may be required in remote areas where access is more difficult. Although the increase in recent drilling activity has occurred in shallow areas, drilling activity in the deeper areas has been maintained and a normal inventory of wells is available from prior drilling and ready to be connected for production.

- the rig fleet is large enough to maintain both an active oil and gas drilling program;

  There has been a substantial increase in the drilling of both oil and gas wells in the last year. This has resulted in increased rig utilization rates. While the utilization rate is high, drilling and service associations indicate that there is still capacity to support active oil and gas drilling programs.

- deliverability will not be constrained by the lack of demand in the short-term.

  Finally, another key assumption is that deliverability is not constrained by demand in the short-term. The basis for this assumption is that pipeline capacity will be expanded by up to 42 million m^3/d (1.5 Bcf/d) when the Alliance Pipeline enters service in November 2000. This will result in a period of excess capacity as the market adjusts to the incremental capacity provided by this new pipeline.

In summary, the decline rate of existing production and the production from new wells, as determined from the production profiles of typical wells (consisting of decline rates and initial productivity) and drilling activity, are the key factors that determine future deliverability. These factors are examined in more detail in the next chapters.

HISTORICAL PRODUCTION AND DECLINE RATES

Production from existing wells will contribute a significant component of future deliverability over the forecast period. This chapter examines the trends in historical production with a focus on decline rates.

3.1 WCSB Gas Areas

The WCSB includes most of Alberta, significant portions of British Columbia and Saskatchewan, as well as parts of Manitoba and the Northwest Territories. Within this vast area, the topography and geology vary significantly, influencing the exploration and development strategies of the gas industry. For example, with respect to topography, access to lands for drilling is essentially unrestricted in the southeastern part of the basin, which tends to be flat prairies, while the terrain of the western part of the basin, adjacent to the Rocky Mountains, causes access to be more difficult. Toward the northern end of the basin, areas are often covered with muskeg, so drilling has to be carried out in winter when the ground is frozen. As a result, the investment needed to drill a well varies with the topographical characteristics of the location. Generally, limitations to access increase the cost and reduce the amount of drilling and development.

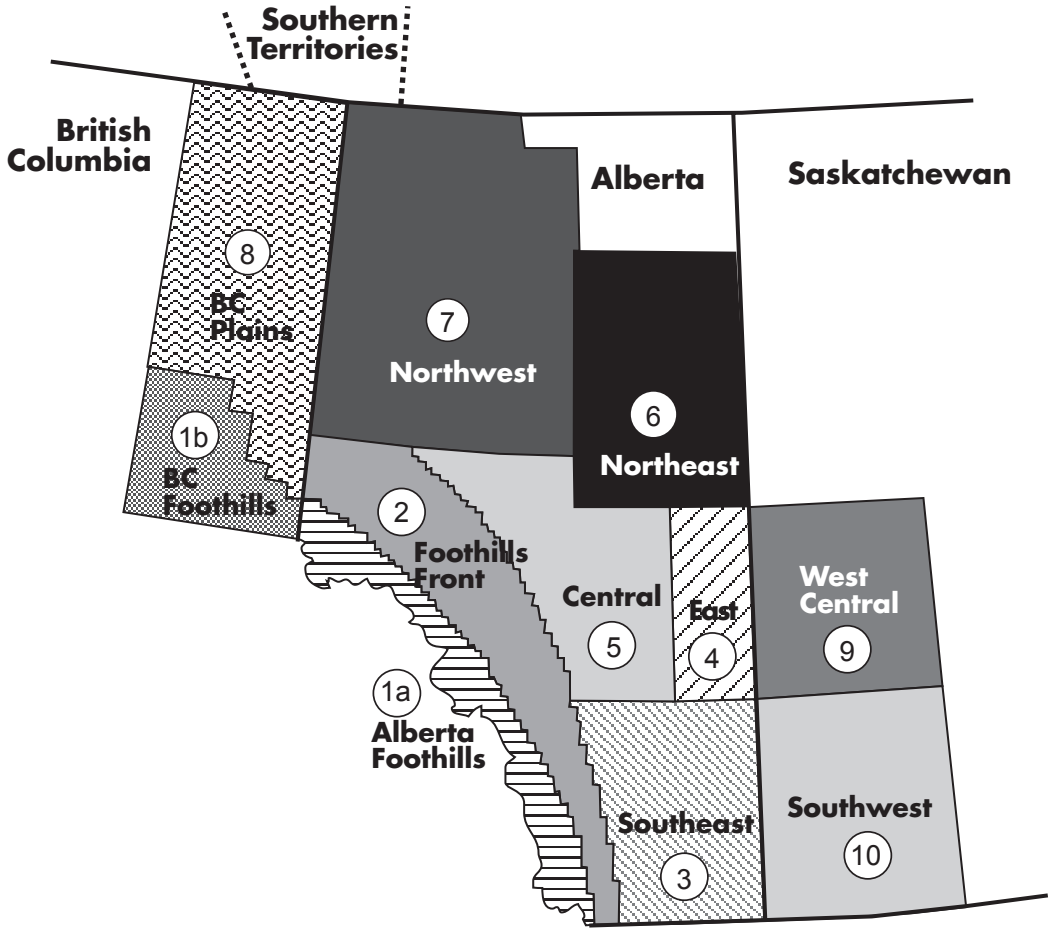
Regional geology can also have a great impact on drilling and costs. Geological formations in the WCSB dip to the southwest resulting in increasing drilling depths and increasing drilling complexity from east to west.

Together, these differences in access and depths result in very large differences in drilling costs across the WCSB. To illustrate, a shallow well in southeastern Alberta or southwestern Saskatchewan may cost less than $100,000, whereas a deep well in the Foothills produces many times more but may cost up to $10 million. Reserves and productivity also tend to vary according to area. The shallow wells in southeastern Alberta and southwestern Saskatchewan generally have initial productivity rates of 6 thousand m^3/d (0.2 MMcf/d). In contrast, some deep wells in the Foothills exhibit initial productivity rates of 600 thousand m^3/d (21 MMcf/d).

The large regional differences in physical characteristics within the WCSB suggest that the basin can be subdivided into smaller areas within which characteristics tend to be similar. For this report, the WCSB has been subdivided into 12 areas based on designations developed by the Petroleum Services Association of Canada (PSAC) although with some modification. PSAC's remaining areas were not included because activity is oil oriented. In addition, its Foothills area was further subdivided by province (1a - Alberta Foothills and 1b - B.C. Foothills). Finally, this study added the southern Territories for a total of 12 areas (Figure 3.1). Each of these areas was analysed independently and individual deliverability forecasts were generated for each area. Any information presented for a larger area, such as the entire WCSB, is derived by summing the results of the individual areas.

FIGURE 3.1

WCSB Gas Areas



3.2 Historical Production

Total marketable gas production from the WCSB has increased from approximately 269 million m^3/d (9.5 Bcf/d) in 1990 to over 465 million m^3/d (16.4 Bcf/d) in 1999. Contributions to this growth in production have varied substantially by geographical area and by the year wells were placed on production.

3.2.1 Production by Geographical Area

Alberta provided about 84 percent of the gas production from the WCSB in 1999, with the remainder provided by British Columbia (12 percent), Saskatchewan (four percent) and a small amount from the Northwest Territories (Table 3.1).

On a regional basis, over one-quarter of the gas production from the WCSB in 1999 was provided by the Foothills Front area. This area has been the largest contributor to WCSB production for many years. Its constant share of total WCSB production indicates that its production has matched the average growth in production for the WCSB. In contrast, northwestern and southeastern Alberta together increased their share of production by five percent since 1995, marking their increasing importance to WCSB deliverability.

TABLE 3.1

Percent Share of WCSB Marketable Gas Production

Province	Area	January 1990	January 1995	January 2000	2000 Rank
Alberta	Foothills	5.3	4.0	3.5	7
	Foothills Front	27.6	25.6	25.7	1
	Southeast	15.2	13.4	14.7	2
	East	4.0	4.3	3.2	8
	Central	18.6	16.2	13.6	4
	Northeast	6.1	8.5	8.6	6
	Northwest	7.6	11.0	14.4	3
	Subtotal	**84.4**	**83.0**	**83.6**	
B.C.	Plains	10.2	10.6	10.3	5
	Foothills	0.7	1.8	1.9	10
	Subtotal	**10.9**	**12.4**	**12.3**	
Sask.	West Central	0.7	1.7	1.1	11
	Southwest	3.9	2.5	2.6	9
	Subtotal	**4.6**	**4.2**	**3.7**	
Territories		0.1	0.3	0.4	12

3.2.2 Production by Connection Year

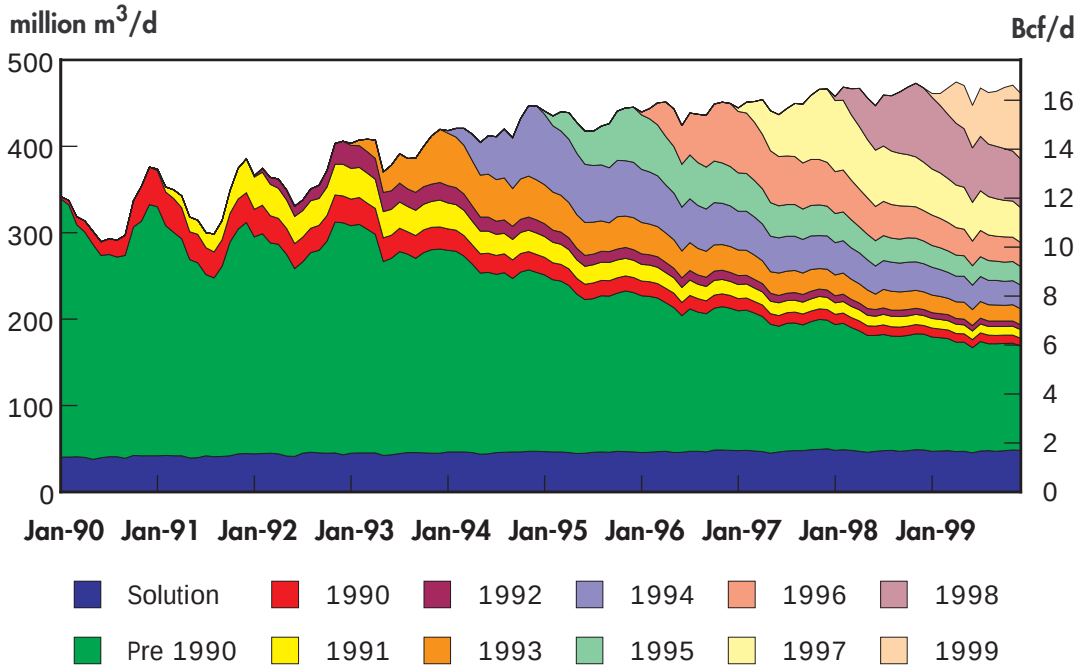
Figure 3.2 shows the marketable natural gas production by connection year. Grouping by connection year shows total production as well as the changes in production characteristics over time. It also demonstrates the importance of drilling activity to deliverability. For example, 50 percent of production for December 1999 was provided from wells connected in 1995 or later. The trend of increasingly steeper slopes also indicates that production rates for recently connected wells are decreasing rapidly; consequently, these wells will be depleted more quickly than older wells. The marketable natural gas production for each individual area is provided in Appendix One.

3.3 Decline Analysis Methodology

In the early stages of basin development, production can often be increased by drawing harder on the existing reserves. However, analyses of the WCSB suggests that nearly all of the existing reserves are producing at capacity. In such an environment, a reservoir engineering technique termed decline analysis can be utilized to provide quantitative values for productivity and decline rates.

FIGURE 3.2

WCSB Marketable Gas Production by Connection Year



The decline in gas production rates for most reservoirs can be represented by an exponential equation. The graphical representation of an exponential decline is a straight line on a plot of the logarithm of the production rate versus time or a plot of the production rate versus cumulative production. This study utilized the latter group of plots.

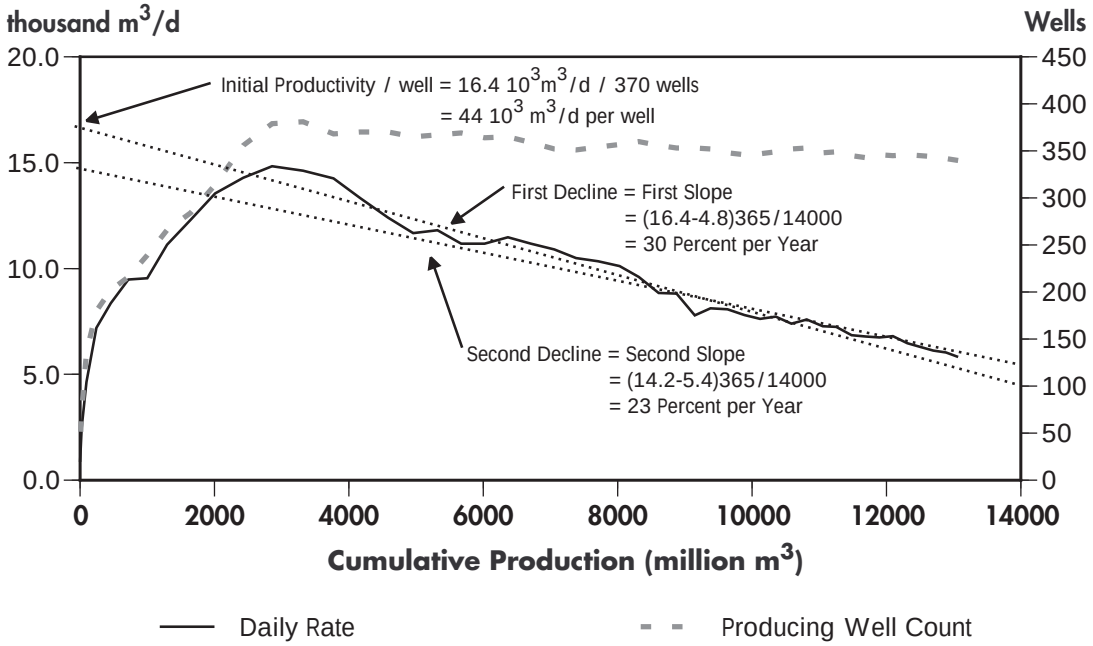
To determine changes in initial productivity by connection year, wells within each of the twelve geographical areas were grouped according to the year they were connected and placed on production, for the period 1990 to 1999. All wells, in each area, connected before 1990 were considered as one group. For each group, a plot of the production rate versus cumulative production was created. The slope of these plots represents the decline rate and shows exponential decline when the slope is constant. However, there are many cases where production will initially decline rapidly for a year or two and later stabilize at a lower decline rate. The production plots of rate versus cumulative production for these decreasing decline rates were approximated by two separate slopes (Figure 3.3).

The initial production rate of a typical well within each group was also calculated. First, the initial productivity of the group of wells was determined by extrapolating the straight line of the rate versus cumulative production Plot back to zero cumulative production or, the point when the group began producing (Figure 3.3). Next, the initial productivity from this group of wells was divided by the number of wells that were still producing at the end of the specific connection year to provide the initial rate for a typical well in the group. This initial production rate represents the first month of production.

Once the decline rate and initial productivity have been determined, a production profile for a typical well in a specific geographic area and specific connection year can be established. This exercise is repeated until production profiles are determined for wells in each connection year for each geographic area. The production profiles for typical wells in each geographic area are discussed in more detail in Chapter 4.

FIGURE 3.3

Sample Rate versus Cumulative Production Plot



3.4 Decline Rates

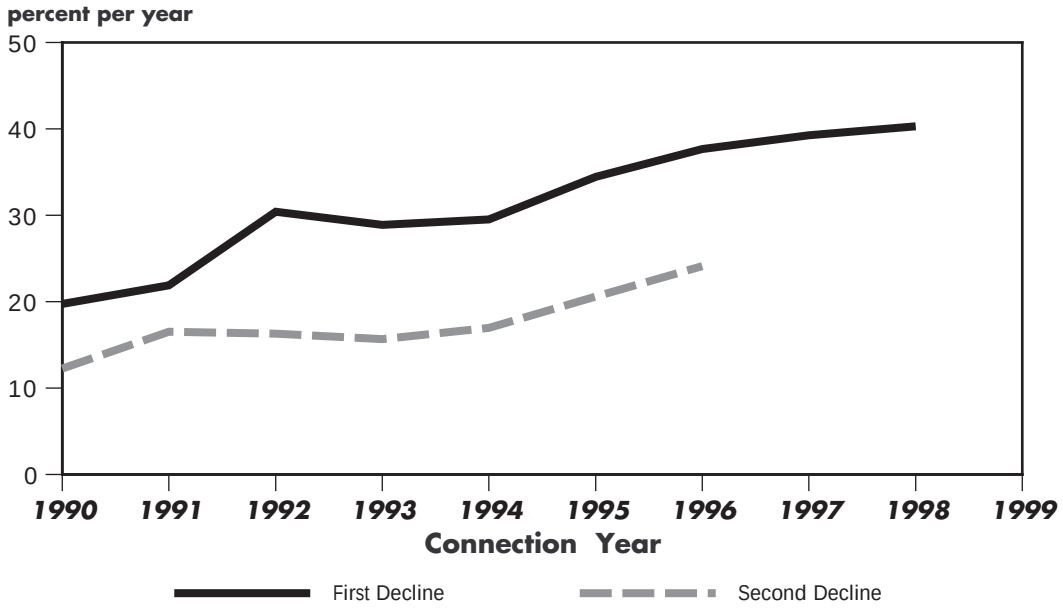
Decline analyses of the rate versus cumulative production charts for each connection year were performed for each individual area (1996 provided in Appendix Two as examples). The weighted average, by well count, for these areas represents the overall WCSB decline rate for that specific connection year (Figure 3.4). This analysis of production rate versus cumulative production plots quantifies and confirms the increasing slopes of each successive connection year as observed from Figure 3.2. Specifically, recently connected wells are being produced at higher rates, relative to their reserves, than older wells; therefore, reserves from new wells will be depleted in a shorter period of time. The decline rates for individual areas are provided in Appendix Three.

The nominal decline rate during the first year or two of production for wells connected in 1997 and 1998 has reached approximately 40 percent; however, the performance of previously connected wells suggests that these decline rates will stabilize at lower levels after about two years of production. An estimate of the overall decline rate for the WCSB can be determined by extrapolating the decline rates for each connection year. Production from currently connected wells in the WCSB is declining at an average rate of 20 percent per year (reflecting a large number of older wells that are declining at lower rates).

Overall, the analysis indicates that, given current decline rates, production from new wells must amount to 85 million m^3/d (3 Bcf/d) in each year to offset declines in existing production.

FIGURE 3.4

WCSB Average Decline Rates by Connection Year



INITIAL WELL PRODUCTIVITY OF TYPICAL WELLS

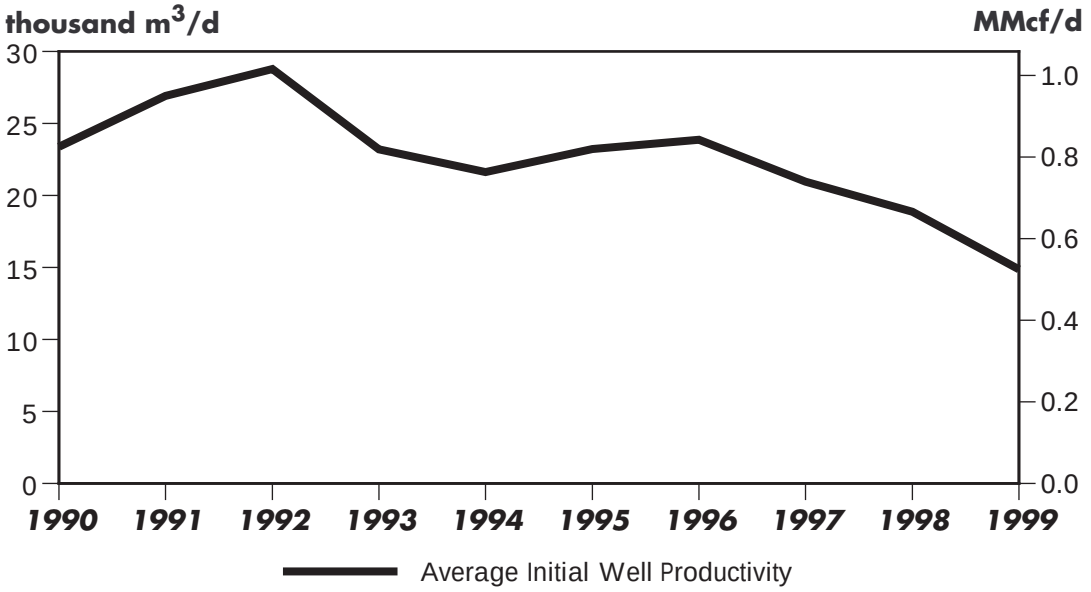
Changes in assumptions with respect to initial well productivity from new wells will have a greater impact on a short-term deliverability forecast than changes in assumptions with respect to decline rates. This reflects the fact that decline rates have a greater long term effect. This chapter examines the trends in initial well productivity.

4.1 Average Initial Well Productivity

As discussed in Section 3.3, the Board's analysis was performed for each individual area. However, for illustrative purposes only, average values for initial well productivity for the entire WCSB were calculated for each connection year (Figure 4.1). For the WCSB, average initial well productivity declined moderately from 1990 to 1996 and more rapidly from 1996 to 1999. The declining average well productivity reflects changes in productivity as well as shifts in drilling activity from high productivity areas to lower productivity areas. Many of the wells connected recently have been in areas with low productivity, such as southeastern Alberta. The average well connected in 1999 had an initial productivity of 15 thousand m3/d (0.5 MMcf/d), down from over 25 thousand m3/d (0.9 MMcf/d) in the early 1990s.

FIGURE 4.1

Average Initial Well Productivity by Connection Year



4.2 Typical Well Production Characteristics

As discussed in Chapter 2, future deliverability from new wells can be projected as the combination of a production profile for a typical well and a drilling forecast. The production profile for a typical well is based on the initial well productivity and the decline rate. Because short-term deliverability is affected more by initial productivity, estimates for this parameter were projected for each year of the forecast, while a single estimate for a decline rate for each area was used.

4.2.1 Historical Production Characteristics

While a forecast is based on the anticipated production characteristics of a typical well rather than on historical values, it is necessary to examine the latter in order to verify the forecasting technique. The forecasting technique was verified through the use of 'history matching': a technique involving an attempt to duplicate four years of production through the forecast methodology. The historical production characteristics of typical wells for each area are summarized in Table 4.1.

The production characteristics represent averages of actual producing rates and decline rates for all producing wells for a specific time period and area under consideration. In discussions with producers, these production characteristics were confirmed to be representative of a typical well.

4.2.2 Forecasting

Table 4.1 shows that the initial well productivity for a typical well will vary by geographic area and by connection year. This trend will likely continue; consequently, it is necessary to forecast the production characteristics for each area before overall deliverability is determined.

TABLE 4.1

Historical Production Characteristics for Typical Wells

		First Decline Rate	Start of Second Decline	Second Decline Rate	Initial Productivity							
					$10^3m^3/d$				MMcf/d			
Connection Year					96	97	98	99	96	97	98	99
Province	Area	%	Months	%								
Alberta	Foothills	18	NA	18	136	102	102	79	4.80	3.60	3.60	2.80
	FH Front	35	18	25	45	37	42	37	1.59	1.30	1.50	1.30
	SE	48	25	18	10	11	9	7	0.35	0.40	0.31	0.24
	East	40	30	30	16	15	12	10	0.55	0.53	0.42	0.35
	Central	52	16	28	25	20	20	16	0.88	0.71	0.71	0.58
	NE	33	18	18	18	14	15	19	0.63	0.50	0.54	0.67
	NW	35	NA	35	45	35	34	33	1.60	1.25	1.20	1.15
B.C.	Plains	40	15	15	52	44	37	31	1.82	1.57	1.30	1.08
	Foothills	22	NA	22	306	416	425	425	10.80	14.70	15.00	15.00
Sask.	WC	50	18	15	12	11	14	12	0.44	0.38	0.50	0.44
	SW	40	14	20	3	3	3	2	0.11	0.12	0.12	0.10

There are many factors that will influence the type of wells connected over the forecast period, but decisions by the producing industry with respect to investing in development wells versus exploration wells will have the most immediate impact. The low oil commodity prices of 1997/1998, which reduced cash flow, caused the producing industry to concentrate on minimizing its risk by developing the existing reserves inventory. Recent increases in oil (and natural gas) commodity prices may encourage industry to shift from development to exploration wells. If this scenario is realized, more prolific wells could be drilled and placed on production.

For this forecast, it was assumed that the producing industry would follow the same development/exploration strategies, within a geographical area, that it used from 1996 to 1999. Based on this assumption, most geographic areas would experience decreasing initial well productivity as producers continue to drill primarily development wells. Future production characteristics were estimated by extrapolating the plots of decline rates and initial well productivity (Appendix Three). The expected values for these parameters are summarized in Table 4.2.

TABLE 4.2

Production Characteristics for Typical Wells - Forecasting

		First Decline Rate	Start of Second Decline	Second Decline Rate	Initial Productivity					
					$10^3m^3/d$			MMcf/d		
Connection Year					0	1	2	0	1	2
Province	Area	%	Months	%						
Alta.	Foothills	18	NA	18	91	85	79	3.20	3.00	2.80
	FH Front	35	18	25	37	35	33	1.30	1.24	1.16
	SE	55	25	23	6	6	6	0.22	0.22	0.22
	East	45	30	30	9	8	8	0.32	0.29	0.27
	Central	52	18	28	18	18	17	0.65	0.62	0.59
	NE	36	18	18	17	17	17	0.59	0.59	0.59
	NW	38	NA	38	34	33	31	1.20	1.15	1.10
B.C.	Plains	45	15	25	31	30	28	1.10	1.05	1.00
	Foothills	22	NA	22	425	425	425	15.00	15.00	15.00
Sask.	WC	50	18	15	13	13	13	0.45	0.45	0.45
	SW	45	14	20	3	3	3	0.11	0.11	0.11

DRILLING ACTIVITY

In addition to initial well productivity, future deliverability from new wells is directly dependent on the number of wells added through drilling activity.

5.1 Well Count Terminology

Estimates of well completions in the WCSB are available through various publications. These estimates are often used as an indicator of industry activity and future production. It is common practice to consider well completions as those wells that are capable of production, but other terms with different meanings are sometimes interchanged. This interchange of terms and the methods used to retrieve data may result in different estimates of drilling activity.

Normally, the term completions refers to wells that have had casing installed and are ready for production. However, some wells that are deemed as completions may not have been tested after drilling and some that have been tested may never be connected to a gathering system if test results are unsatisfactory. In addition, some wells that are classified as producing gas wells may only produce for very short periods. Gas wells that did not produce beyond the year in which they commenced production were not considered to be successful wells by this report.

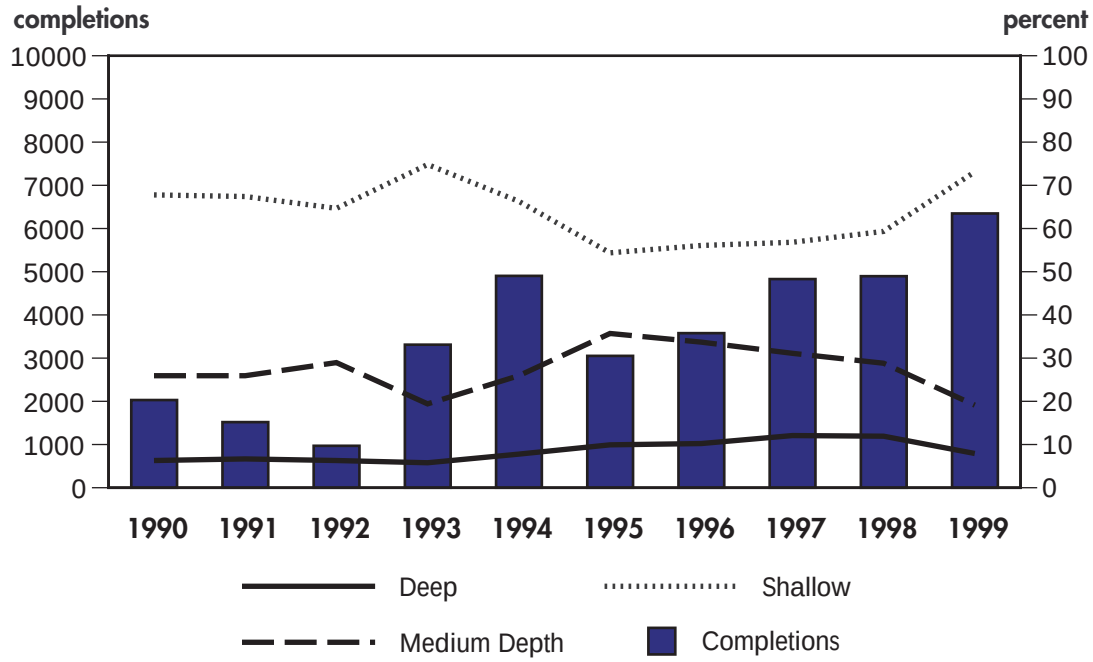
Further complicating matters is the fact that there are multiple zones in some wells, so that the number of zones reported as having produced some amount of gas exceeds the number of well completions. However, the number of zones that have sustained production (or that the Board considers as successful wells) are about the same as the number of completions.

5.2 Gas Well Completions

Since 1995, the number of gas well completions has more than doubled with a sharp increase occurring in 1999 (Figure 5.1). The record number of gas well completions in 1999 led to expectations of substantial deliverability increases. However, this increase in deliverability did not materialize, in part, due to the high concentration of shallow gas well completions in southeastern Alberta and southwestern Saskatchewan. In fact, during the past decade, more than 60 percent of total gas well completions have been in shallow areas although these areas provide less than 30 percent of total WCSB production due to lower than basin average well productivity. Thus, a great number of these low productivity wells are needed to substantially increase overall WCSB deliverability. Historical gas well completions for each area are provided in Appendix Four.

FIGURE 5.1

WCSB Gas Well Completions



Source: Geoscout for Windows[1]

5.3 Gas Well Investments

Considering the regional differences in well productivity and drilling costs, the producing industry's effort to increase overall deliverability may be better reflected by the capital it invests in gas well drilling than by the number of wells it drills. For example, gas wells in the deeper part of the basin are much more costly but well productivity is much greater than those in the shallow areas.

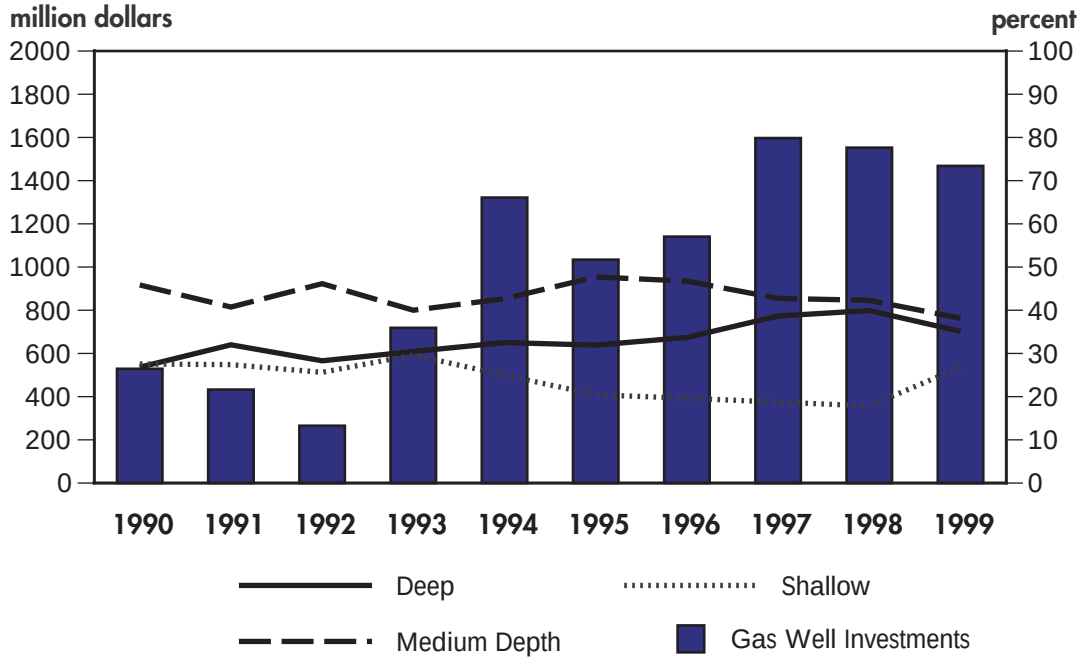
For this report, an approximation of industry capital expenditures for gas well drilling was determined for each geographical area (excluding Territories) by multiplying the number of completions in each area by a typical well cost (Appendix Four). These expenditures represent only a portion of the total capital invested by industry - additional capital is required to purchase land, construct gas processing facilities and to conduct other related activities. The data also show that the shallow areas only account for about 30 percent of the capital for gas well drilling - about the same percentage as the share of production.

Capital expenditures for gas well drilling within the WCSB have declined slightly from 1997 to 1999 reflecting a period of lower cash flow to producers (Figure 5.2). The flat level of capital expenditures has resulted in a flat level of deliverability over the past few years despite the increase in well completions. This is due to the focus of producers on developing gas deliverability in the less expensive and lower productivity areas of the basin. Similarly for 2000, the large increase in well completions to date this year, which have been located mainly in shallow areas, should not be seen as suggesting a corresponding increase in production. Discussions between Board staff and many producers suggest that the industry plans to expand its capital budgets next year and that this expansion should result in increased production.

1 Completions were assumed to be all identified gas wells plus 60 percent of standing wells.

FIGURE 5.2

WCSB Gas Well Investments



5.4 Drilling Forecast

A number of industry associations and analysts are predicting that about 8,000 gas wells will be completed in 2000 and that this level could increase to 9,000 by 2001. PSAC published a report in October 2000, entitled 2001 Western Canada Activity Forecast, which predicts that as many as 9,200 gas wells would be drilled in 2000 and 9,800 in 2001. In its forecast, PSAC also predicts a substantial shift in drilling activity toward the western and northwestern areas of the basin which have deeper and more productive wells.

In arriving at its drilling forecast, the Board relied heavily on the information available from industry. The most recent drilling statistics were also reviewed and compared with 1999 drilling statistics in order to establish any shift in activity from one area to another. Although the Board's drilling forecast involves fewer well counts than the PSAC study, the distribution of wells in the PSAC study was used to determine which geographical areas would likely experience increases in drilling activity. Based on discussions with producers and estimates from industry associations, the Board anticipates that there will be about 8,100 successful gas wells in 2000, followed by 8,700 gas wells in 2001 and 8,900 successful gas wells in 2002. However, considering the varying opinions on future drilling, the Board developed two alternative scenarios as described in section 6.3.

5.5 Other Factors

During discussions with Board staff, several producers identified other factors that have affected the level of industry investment. For example, mergers and acquisitions in the producing sector reduce investment as the consolidated companies need time to evaluate the new portfolio of potential projects. In addition, several producers pointed out that staff reductions, which occurred when prices were lower, mean they may not have the necessary staff levels to conduct re-completion programs or the in-house expertise to pursue exploration in high-risk areas such as the Foothills. Thus, many producers have indicated an intent to continue exploitation of their core areas.

DELIVERABILITY FORECASTS

This chapter contains a deliverability outlook to the end of 2002. Two alternative projections are also provided that show the differences in deliverability which result from different levels of drilling activity.

6.1 Forecasting Techniques

As discussed in Chapter 2, future deliverability from the WCSB was estimated by extrapolating current decline trends in production from existing wells and adding production from new wells connected during the forecast period, in this case 2000 to 2002. The forecast for currently connected gas wells, within one area, is based on the extrapolation of 11 existing production profiles (a profile for pre-1990 wells and a profile for each year from 1990 to 1999).

Another component of deliverability is gas production from oil wells, termed solution gas. Solution gas production has been consistent over many years; accordingly, this trend has been extrapolated to project future solution gas production.

Deliverability from new wells is the product of the production profile of a typical well multiplied by the number of wells added at a particular point in time.

6.2 History Matching

As indicated earlier, the forecasting techniques were verified by history matching, that is using the forecasting techniques to determine if they can match historical production. In this case, the 1996 to 1999 period was simulated by combining the producing characteristics shown in Table 4.1 with the actual number of wells connected during that same period. This results in a history match that follows the general trends of actual production for the WCSB (Figure 6.1) and verifies the assumptions used in the forecasting technique.

The history matches for the individual areas are included in Appendix Five. The forecasts for the individual categories used in the history match reflect actual production values as shown in Figure 3.2 as does the distribution among categories of reserves. In addition, the wells added from 1996 to 1999 contribute close to 50 percent of the production at the end of 1999 as was actually the case.

6.3 Base Deliverability Forecast

Many producers and industry associations are predicting that gas well drilling will continue to increase during the next few years. As noted earlier, the Board's deliverability also assumes increased drilling activity: 8,100, 8,700 and 8,900 successful gas wells added in 2000, 2001, and 2002 respectively. As a result, gas deliverability from the WCSB increases from 465 million m3/d (16.4 Bcf/d) in 1999 to 495 million m3/d (17.5 Bcf/d) by the end of 2002 (Figure 6.2).

FIGURE 6.1

History Matching of WCSB Natural Gas Production, 1996-1999

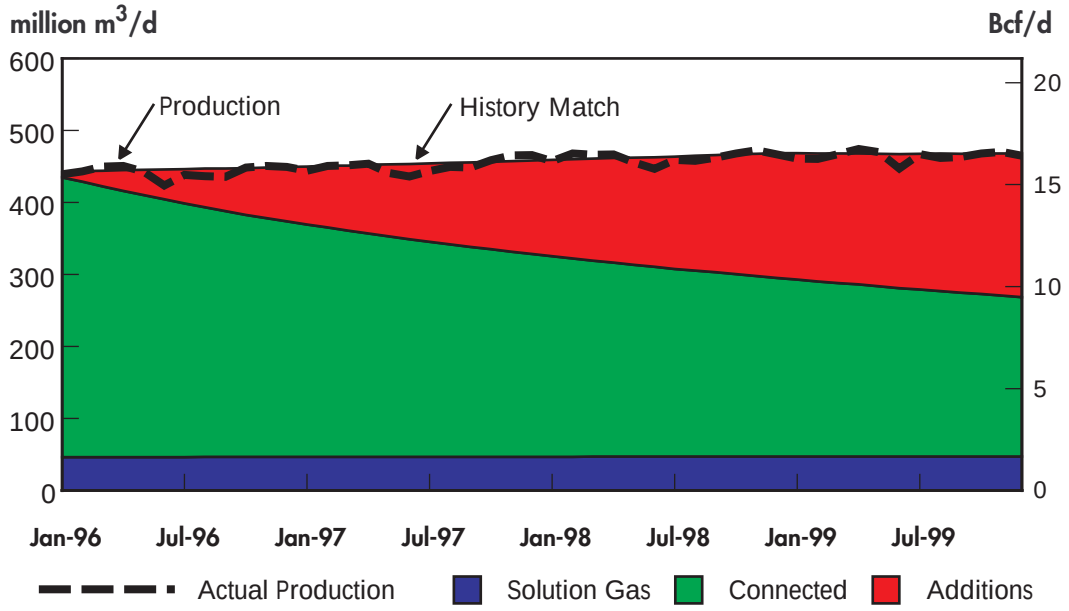
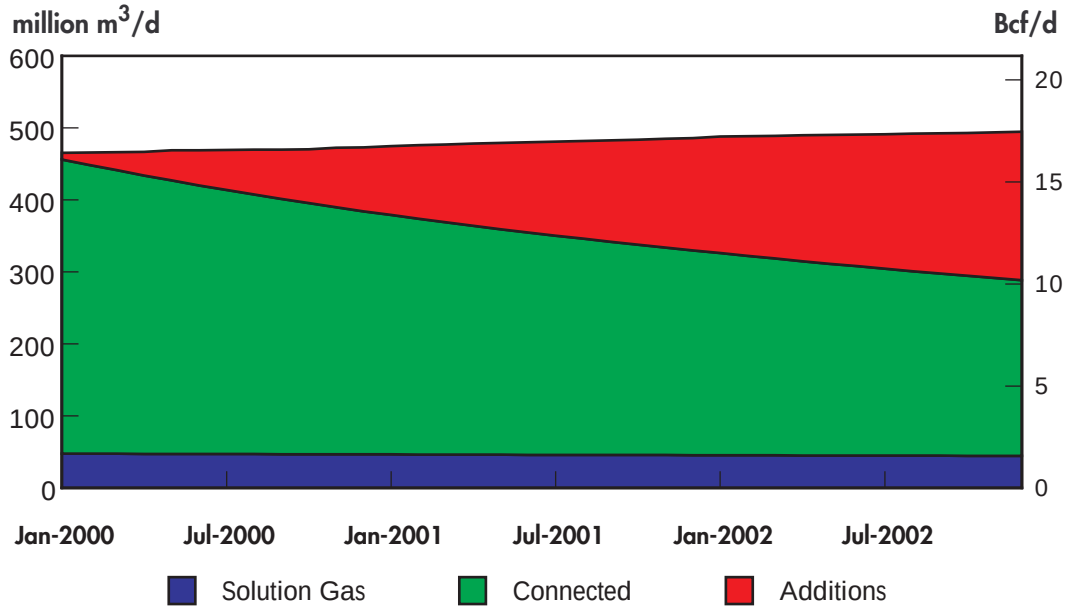


FIGURE 6.2

WCSB Base Deliverability Forecast



The aggressive pattern of drilling underpinning this outlook translates into a 40 percent increase in well connections between 1999 and 2002. While drilling activity is expected to be high in all areas of the WCSB, the largest percentage increases are projected to occur in the medium and deep parts of the basin. This shift to the deeper portions of the basin can also be shown by converting wells to capital investment (based on the individual well costs shown in Appendix Four). Capital investment for gas well drilling is projected to increase more rapidly than well counts. For example, the base deliverability outlook requires a 55 percent increase in capital investment for gas wells from 1999 to 2002. The deliverability forecasts for each individual area are included in Appendix Five.

6.4 Alternative Deliverability Forecasts

Many factors influence industry's decisions and ability to drill wells and industry often responds very rapidly to some of these influences. Therefore the number of wells which will actually be drilled could vary from those used in this forecast. A change in number of wells has a direct impact on deliverability. Moreover, the same impact could be realized if there is a geographical shift in gas well drilling. Therefore, two alternative deliverability forecasts, assuming different drilling levels, are presented in this section.

6.4.1 Initial Well Productivity

Before turning to the alternative drilling forecasts, an observation on the impact of using different production characteristics can be made by comparing the results of the Board's September 1999 forecast with this deliverability outlook. The previous report suggested that WCSB deliverability could increase by about 62 million m3/d (2.2 Bcf/d) over three years by drilling some 5,000 wells per year. The present forecast shows an increase of 30 million m3/d (1.1 Bcf/d) over the same time frame based on drilling 8,100 wells in 2000 and increasing to 8,900 wells by 2002.

The previous report was based on the initial productivity data available at the time; moreover, it was assumed that these rates would remain stable throughout the forecast period. In fact, recent production data show that there has been a substantial decrease in initial productivity rates for wells across the WCSB. More specifically, the initial productivities for wells connected in 1999 are nearly 40 percent lower than those for wells connected in 1996. The differences in initial productivity account for the different well requirements in the two reports.

6.4.2 Alternative Drilling Scenarios

Considering the wide range in production characteristics and costs within the WCSB, the location of future wells is very important. This diversity can be partially taken into account by examining capital investment for gas well drilling along with total well count.

The number of wells considered for these two additional cases, along with the base forecast for the entire WCSB, are shown in Figure 6.3 (deliverability and well counts for individual geographical areas are included in Appendix Six).

The first scenario assumes that drilling activity will remain constant at 8,100 wells per year as compared with the base case which assumes an increase in drilling activity in 2001 and 2002. Over the three year forecast period, this alternative case results in 95 percent of the wells and 89 percent of capital spent in the base case. This scenario results in deliverability of 470 million m3/d (16.6 Bcf/d) by 2002, or in other words, about the same level as current deliverability.

The second scenario involves the same well activity for 2000 as in the base case but utilizes PSAC's 2001 estimate of 9,800 wells and patterns of well distribution for 2001 and 2002. Over the forecast period, this scenario results in an increase of eight percent over the base case in terms of total well count and a further 18 percent increase in capital investment. This substantial increase in capital investment (about 90 percent more than 1999) reflects a considerable shift in drilling toward medium and deeper areas of the basin. The second scenario results in deliverability reaching 530 million m3/d (18.8 Bcf/d) by 2002 or about 37 million m3/d (1.3 Bcf/d) higher than the base case (Figure 6.4).

These alternative outlooks demonstrate that deliverability generated from the WCSB varies substantially according to the level of drilling activity and the location of the drilling.

FIGURE 6.3

WCSB Gas Well Completions and Drilling Scenarios

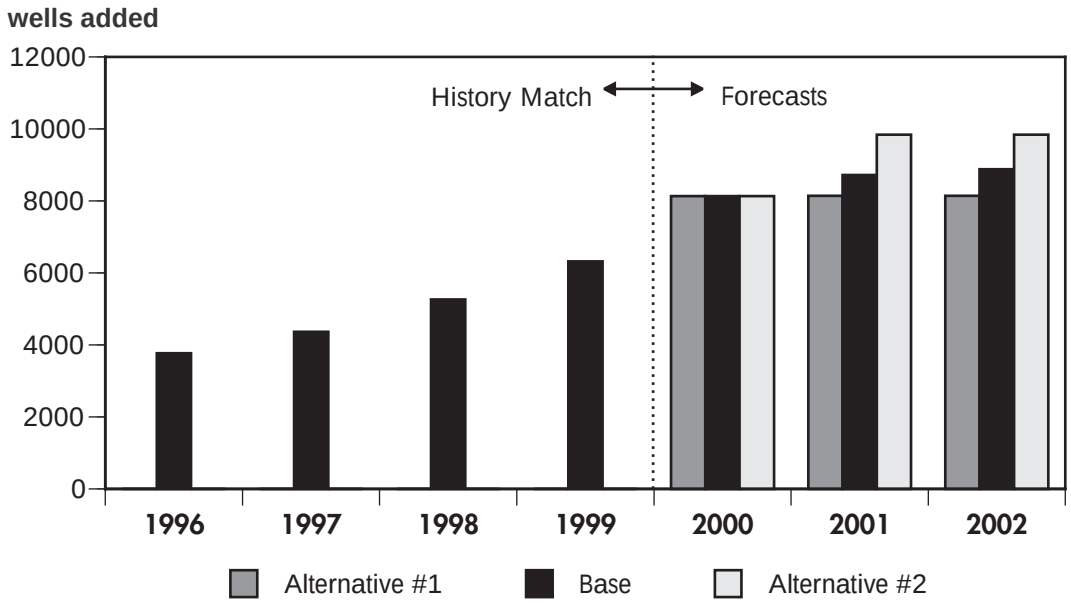
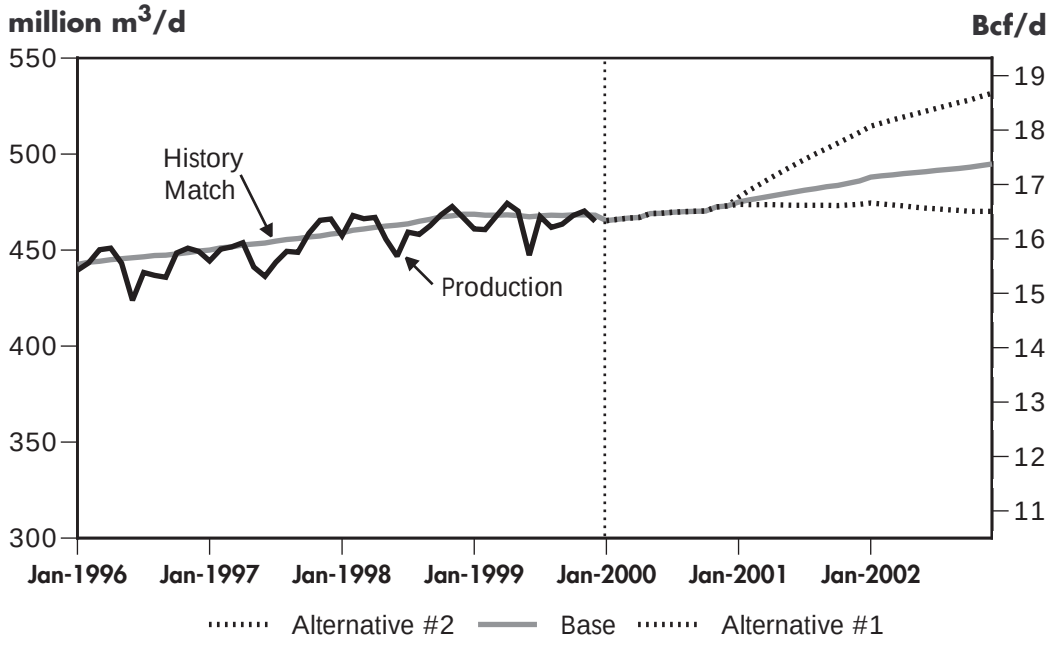


FIGURE 6.4

WCSB Base and Alternative Deliverability Forecasts



SUMMARY AND CONCLUSIONS

Despite the drilling of a record number of gas wells in 1999, natural gas deliverability from the WCSB increased only marginally. An examination of the production characteristics of wells connected over the last four years shows that the average initial productivity per well has been declining, in part due to the drilling of an increasing number of shallow gas wells.

The declining rate of production from all existing wells is another significant factor affecting deliverability. To offset the annual decline in production from existing wells, production from new wells added in one year must amount to at least 85 million m3/d (3 Bcf/d) in each year, or 20 percent of current production.

The decrease in initial productivity per well within the WCSB has been much more rapid than previously anticipated. To compensate for this trend of declining well productivity, an increasing number of wells has to be drilled to increase overall natural gas production from the WCSB. A shift in drilling strategy to higher productivity areas in the WCSB would temper the number of wells required to increase deliverability.

The Board now expects that deliverability from the WCSB could increase gradually to 495 million m3/d (17.5 Bcf/d) by 2002 - an increase of some 30 million m3/d (1.1 Bcf/d) over current production. However, to achieve this level of deliverability, up to 8,900 wells per year would be required by 2002, along with a shift in drilling activity toward the deeper and more productive areas of the basin.

There are a number of uncertainties that will affect deliverability from the WCSB, the major factor being the level of drilling activity. If drilling levels reach 9,800 wells, as projected by the Petroleum Services Association of Canada, deliverability would increase to 530 million m3/d (18.8 Bcf/d) by 2002. This represents an increase of 70 million m3/d (2.4 Bcf/d) or 15 percent above current deliverability. On the other hand, deliverability would remain essentially flat if drilling levels were sustained at around 8,100 wells per year.

Casing	Pipe which is cemented with well bore to isolate geological zones from one another.
Connected Gas Well	A gas well which has been connected to a gathering and processing system and thus is producing or ready to produce.
Completed Gas Well	A well which has normally tested gas, has casing in its well bore, is nearly ready to produce but has not been connected to a gathering and processing system.
Connection Year	The year in which a well is connected to a gas gathering and processing system and begins to produce.
Decline Rate	A term used to describe the decrease in production rate over time. It is usually expressed as a percentage per year. Most common forms are the nominal decline which is the slope of an exponential plot of production rate versus cumulative production. The effective decline is one less the ratio of the production rate at end of a given year to the production rate at the beginning of the same year.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir, field or producing system can supply in a given amount of time.
Long Term Forecast	Forecast beyond the year 2002.
Marketable Gas	Natural gas which has been processed to remove impurities and natural gas liquids. It is ready for market use.
Raw Gas	Natural gas as produced from a reservoir.
Recompleted Gas Well	A well which has been completed in a second zone.
Reservoir	A porous and permeable underground rock containing accumulations of crude oil, natural gas and related substances that is confined by impermeable rock or water barriers.
Short Term Forecasts	Forecast to and including the year 2002.
Storage	Facility or reservoir used to accumulate natural gas during periods of low demand. It is used to deliver natural gas during periods of high demand.
Storage Level	The amount of natural gas in a storage reservoir.
Well Productivity	The amount of natural gas produced by a gas well, under normal producing conditions, over a given period of time. The rate is normally expressed as thousand cubic metres per day (mcf or MMcf per day).

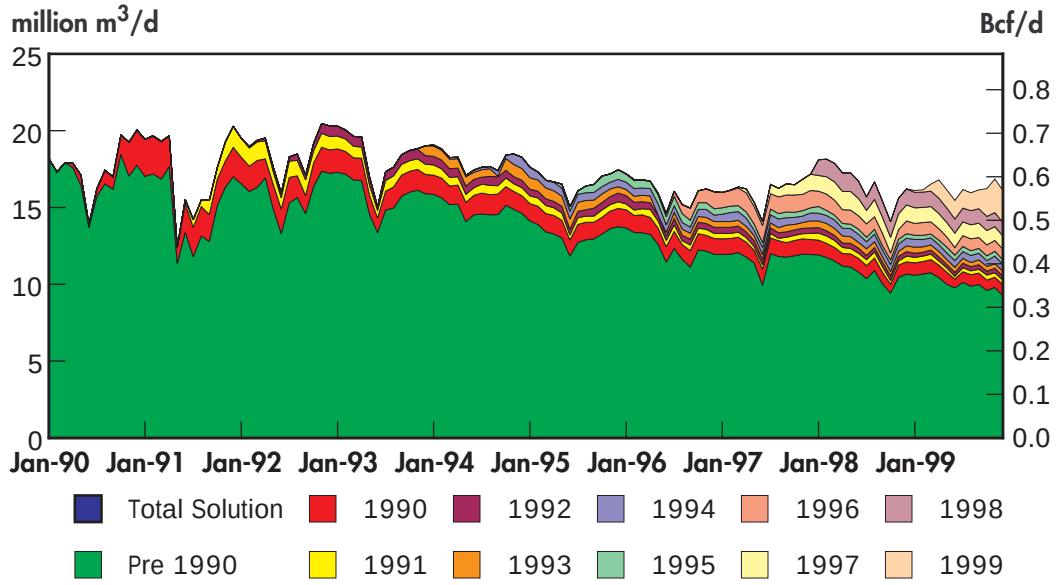
Marketable Gas Production by Area

NATURAL GAS SHRINKAGE FACTORS

Province	Area	Gas Wells	Oil Wells (Solution)
Alberta	Foothills	0.72	NA
	Foothills Front	0.76	0.76
	Southeast	0.93	0.81
	East	0.95	0.85
	Central	0.92	0.74
	Northeast	0.95	NA
	Northwest	0.92	0.71
BC	Plains	0.88	0.78
	Foothills	0.75	NA
Saskatchewan	West Central	0.82	0.80
	Southwest	0.82	0.80

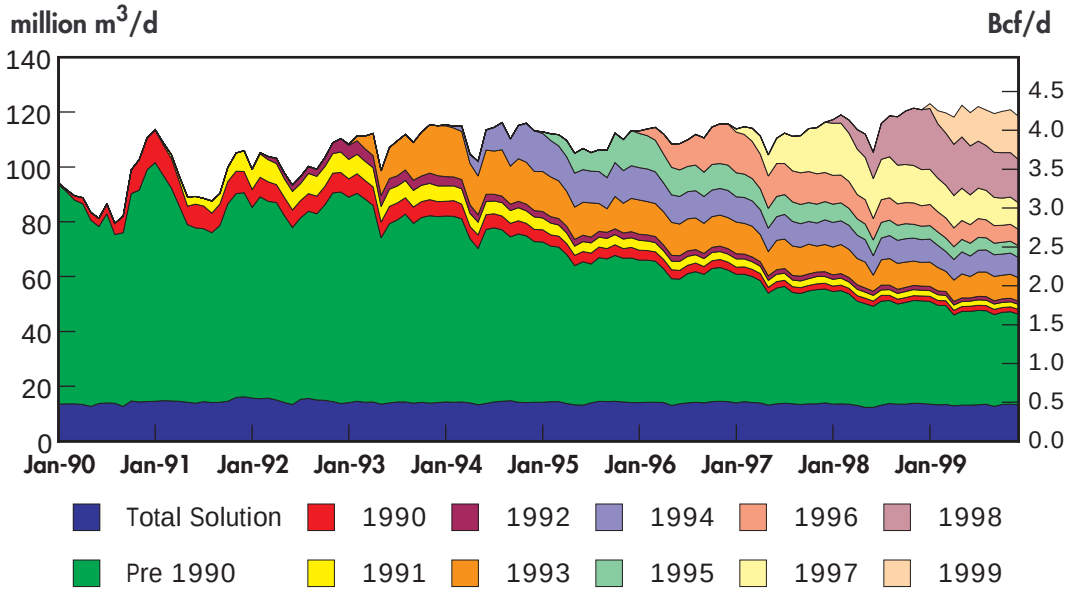
ALBERTA FOOTHILLS MARKETABLE GAS PRODUCTION

Grouped by Connection Year



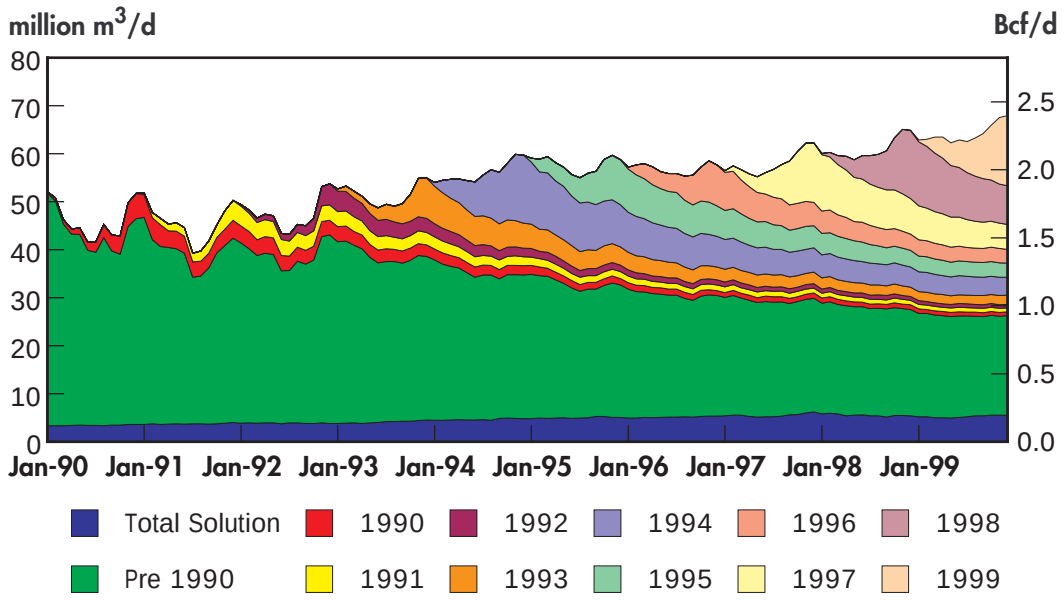
ALBERTA FOOTHILLS FRONT MARKETABLE GAS PRODUCTION

Grouped by Connection Year



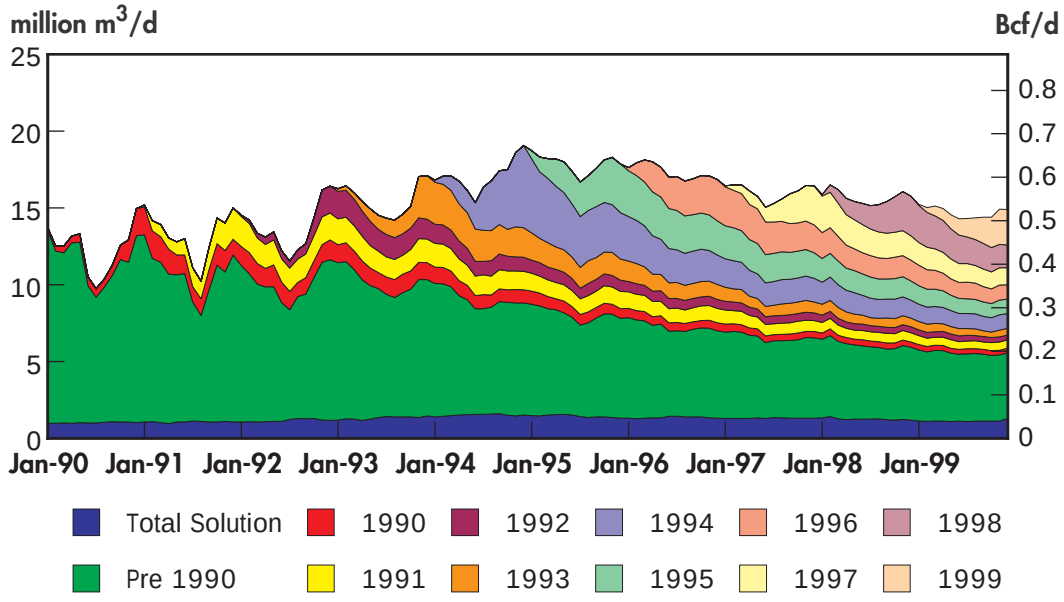
ALBERTA SOUTHEAST MARKETABLE GAS PRODUCTION

Grouped by Connection Year



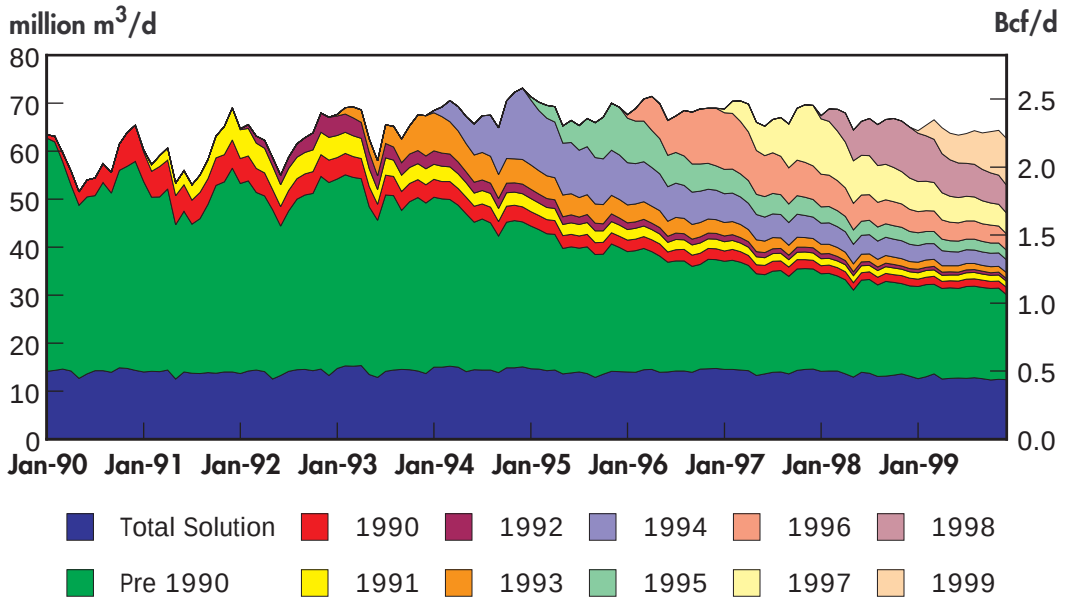
ALBERTA EAST MARKETABLE GAS PRODUCTION

Grouped by Connection Year



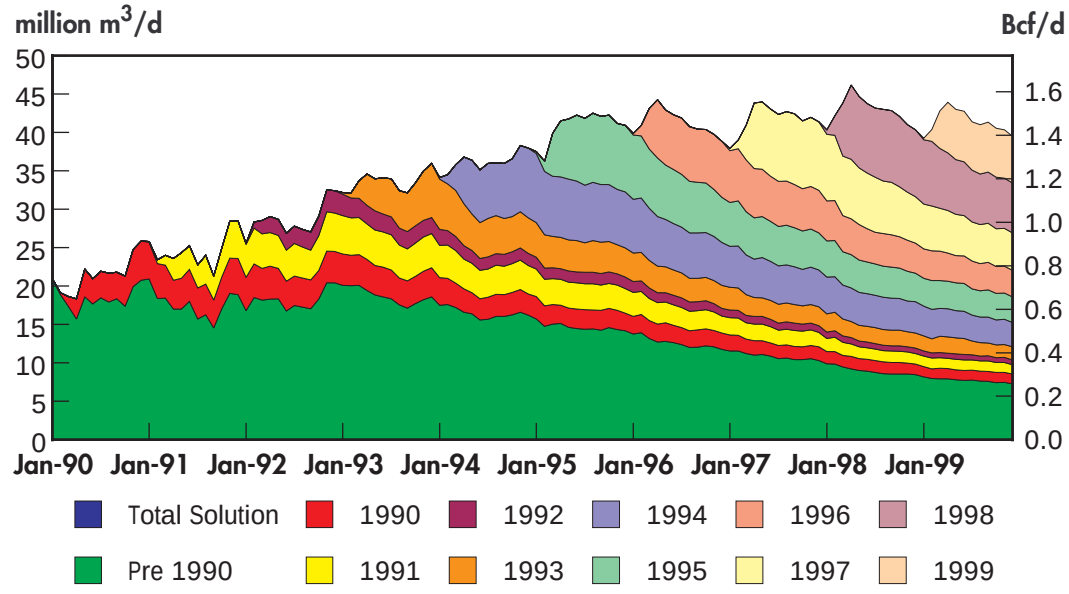
ALBERTA CENTRAL MARKETABLE GAS PRODUCTION

Grouped by Connection Year



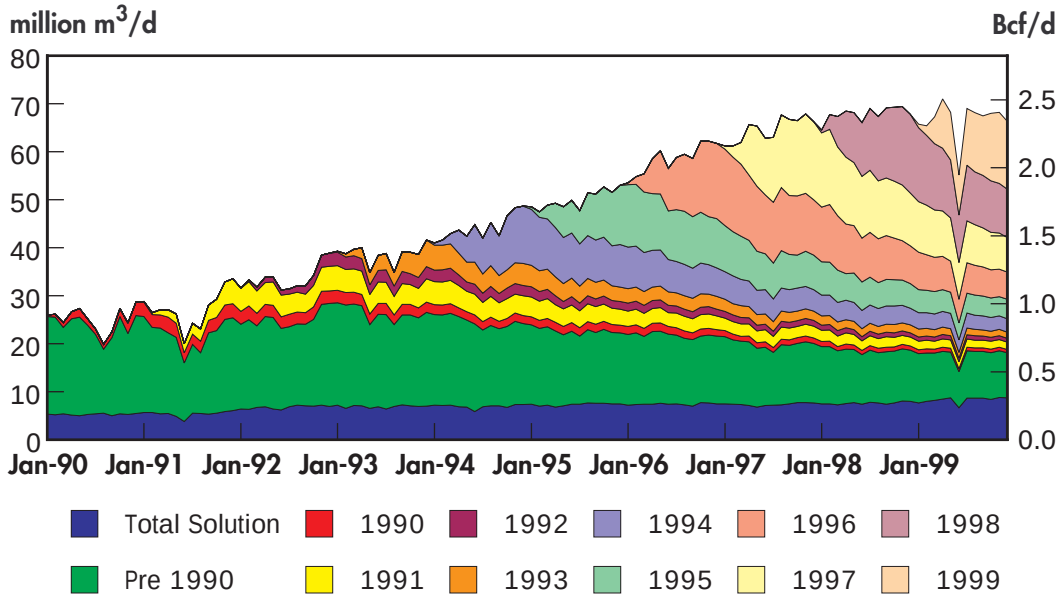
ALBERTA NORTHEAST MARKETABLE GAS PRODUCTION

Grouped by Connection Year



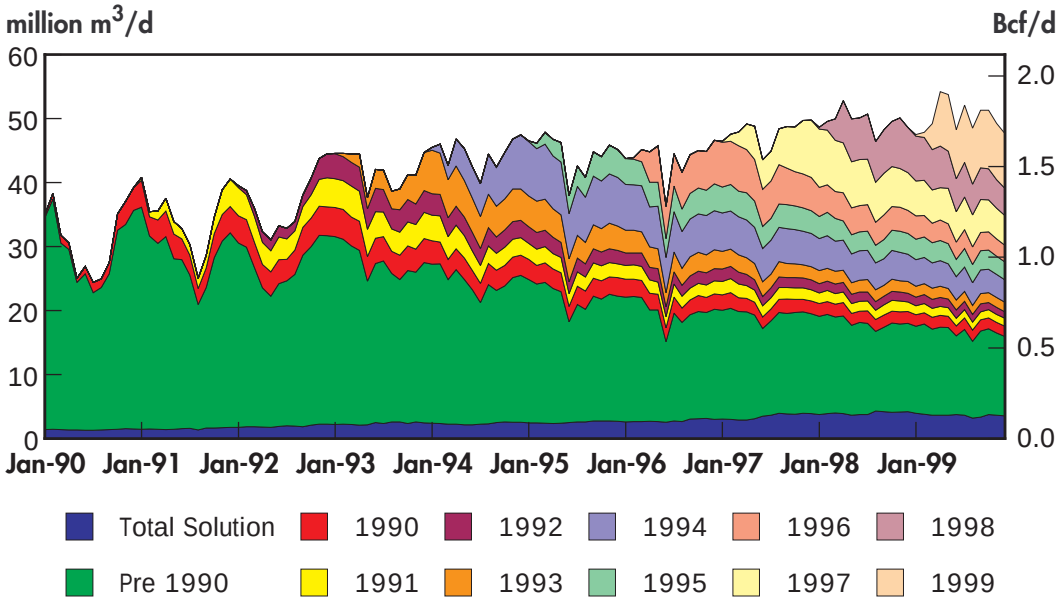
ALBERTA NORTHWEST MARKETABLE GAS PRODUCTION

Grouped by Connection Year



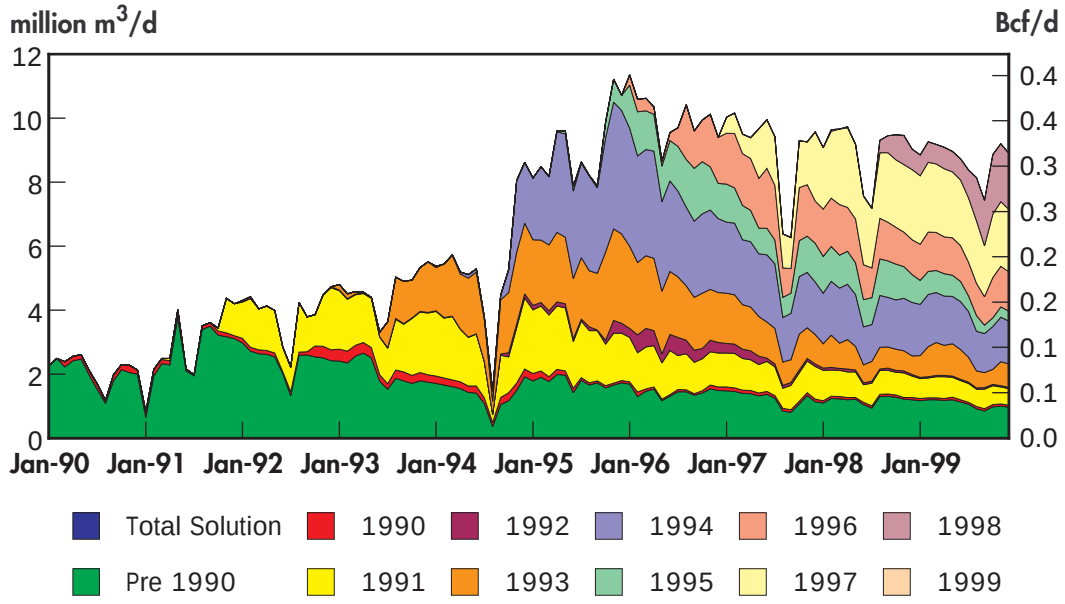
BC PLAINS MARKETABLE GAS PRODUCTION

Grouped by Connection Year



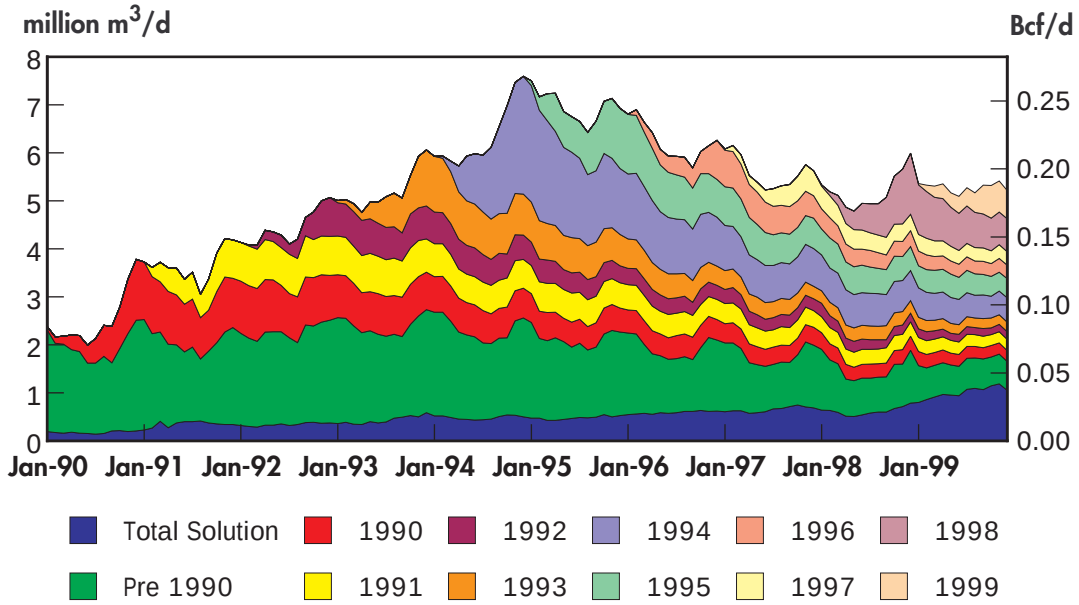
BC FOOTHILLS MARKETABLE GAS PRODUCTION

Grouped by Connection Year



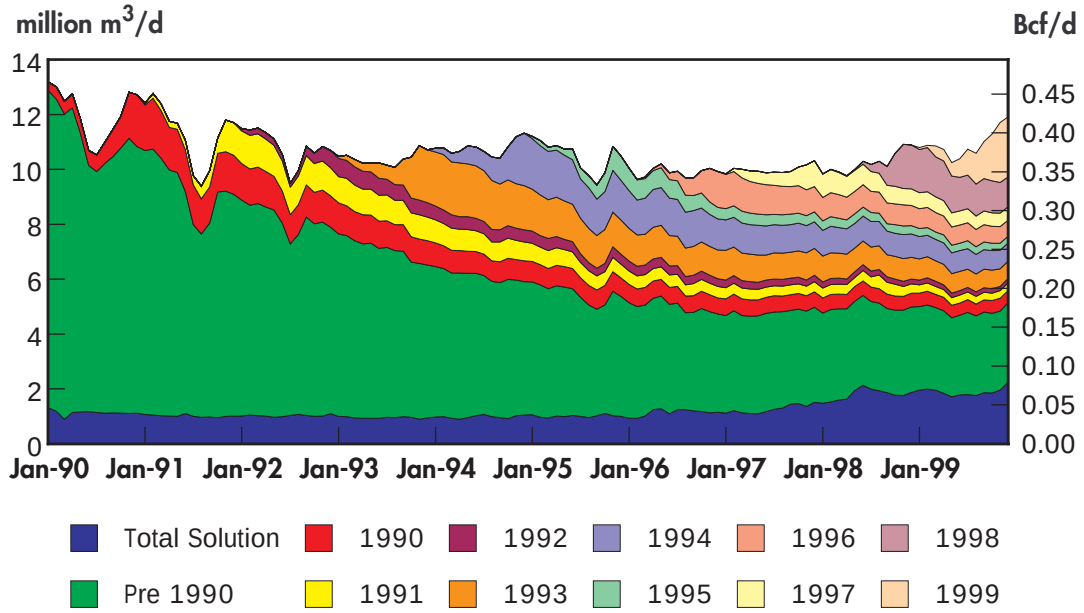
SASKATCHEWAN WEST CENTRAL MARKETABLE GAS PRODUCTION

Grouped by Connection Year



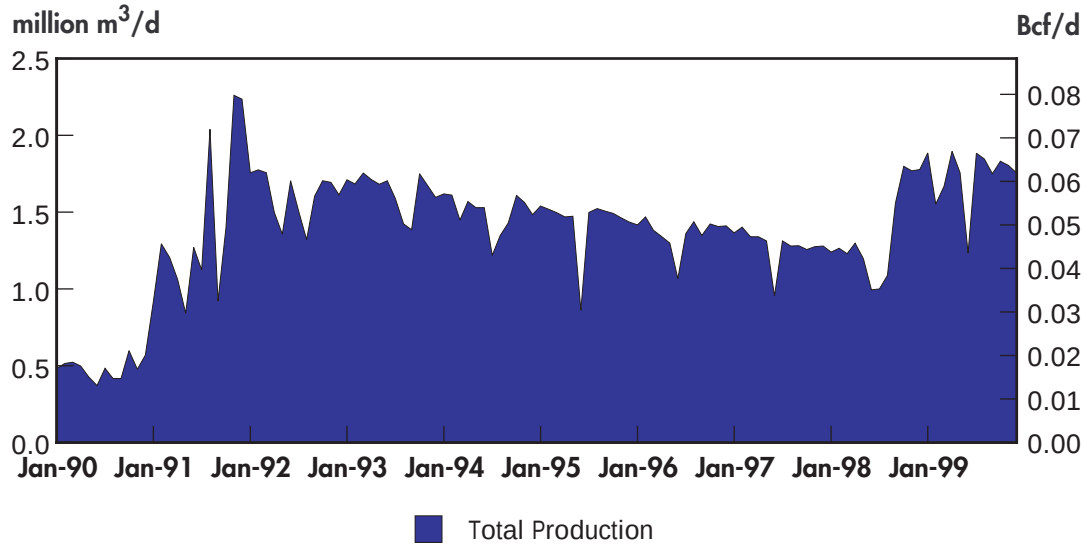
SASKATCHEWAN SOUTHWEST MARKETABLE GAS PRODUCTION

Grouped by Connection Year



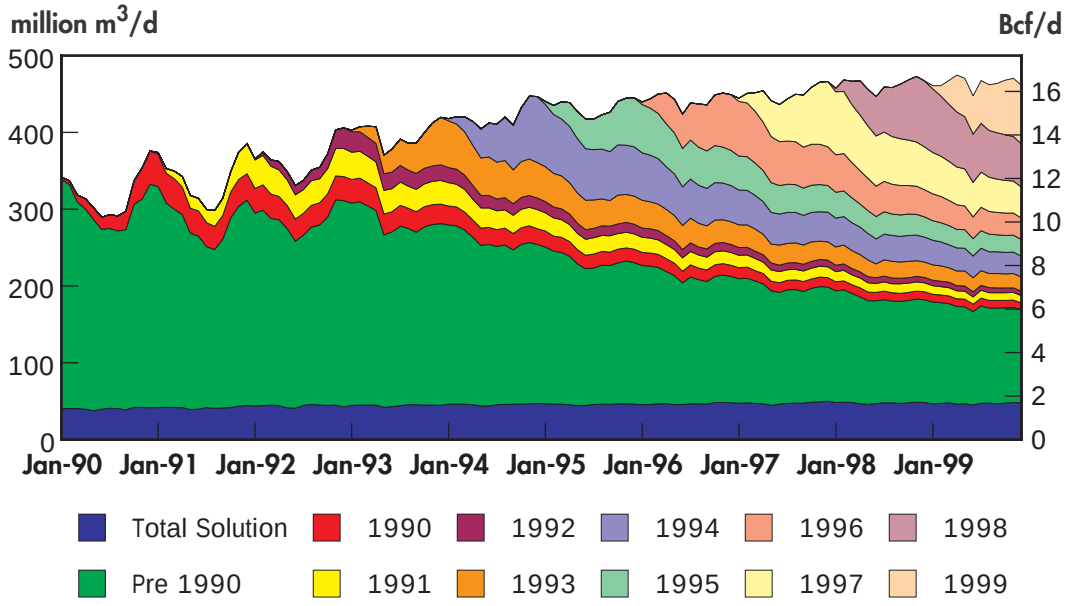
TERRITORIES MARKETABLE GAS PRODUCTION

Grouped by Connection Year



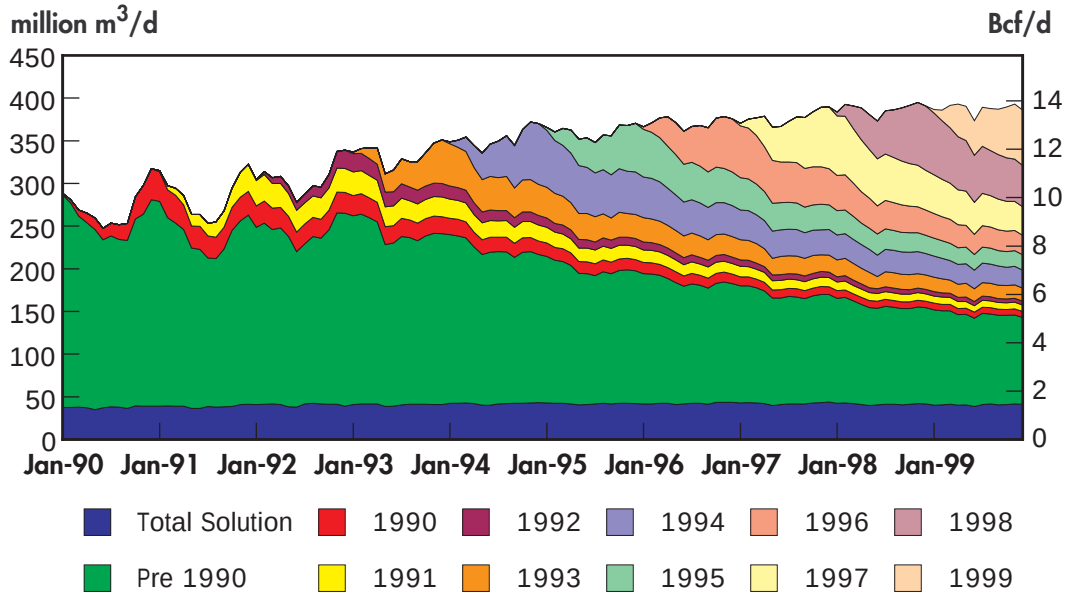
WCSB MARKETABLE GAS PRODUCTION

Grouped by Connection Year



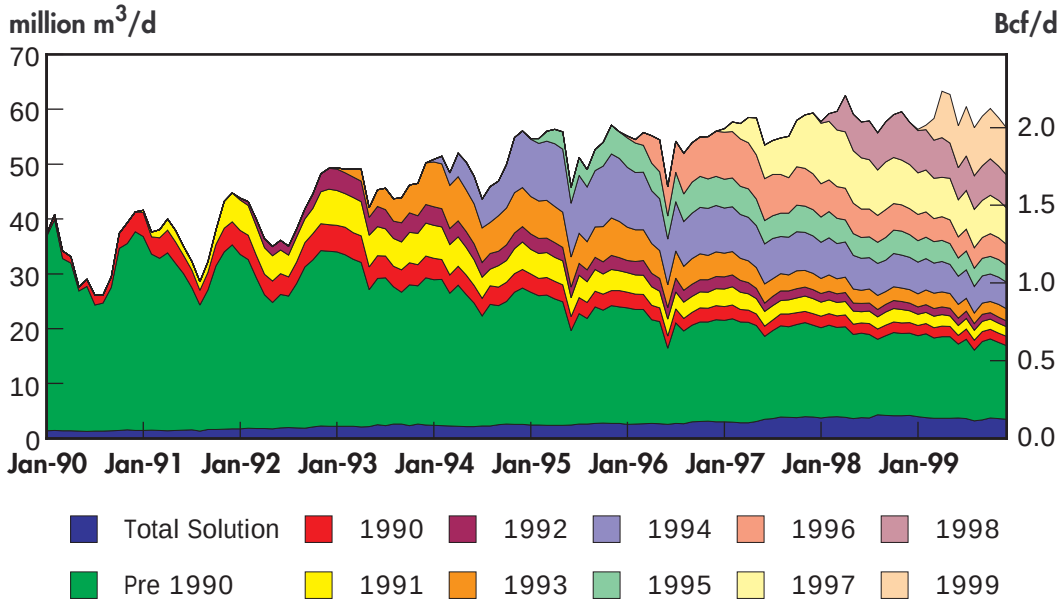
ALBERTA MARKETABLE GAS PRODUCTION

Grouped by Connection Year



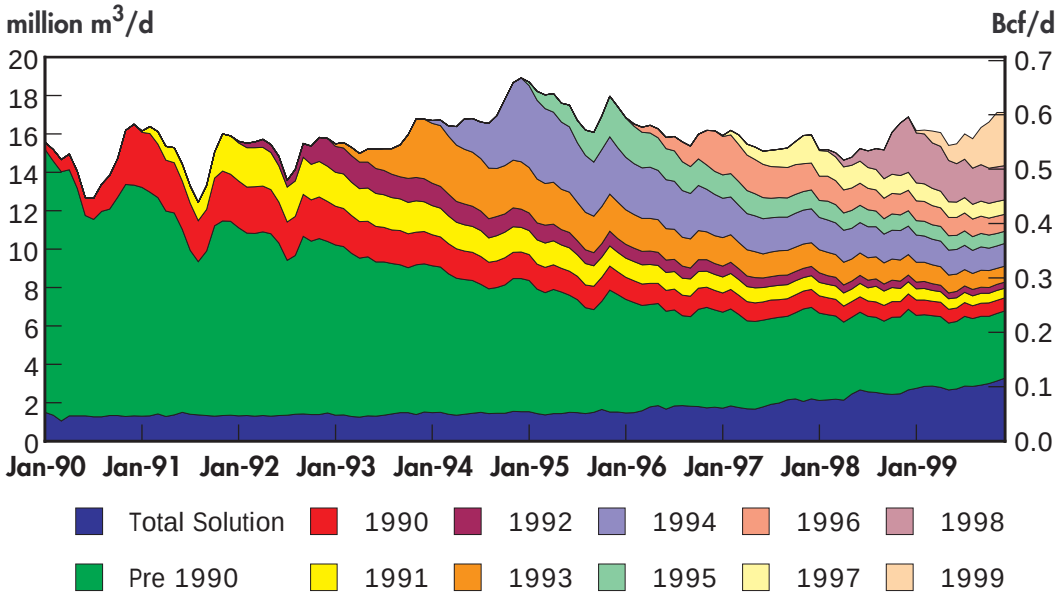
BC MARKETABLE GAS PRODUCTION

Grouped by Connection Year



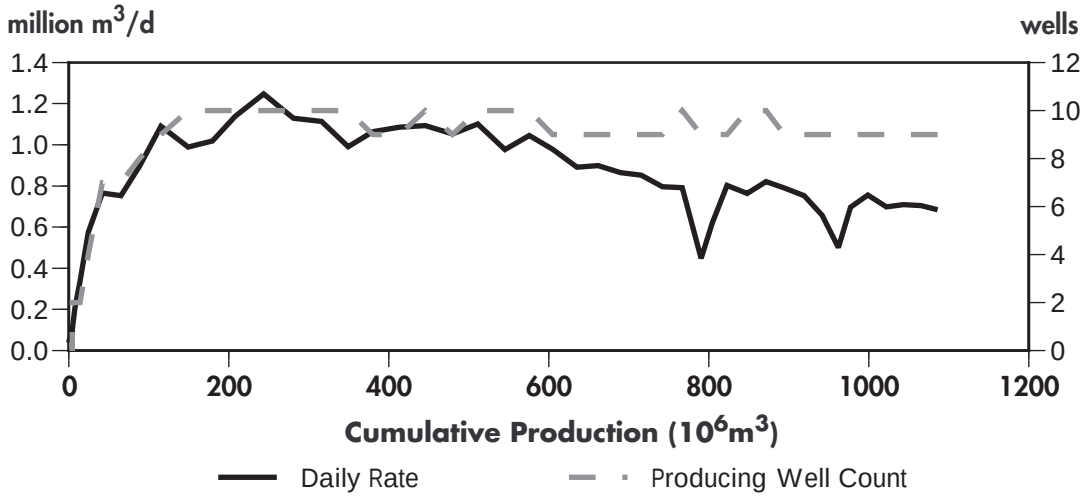
SASKATCHEWAN MARKETABLE GAS PRODUCTION

Grouped by Connection Year

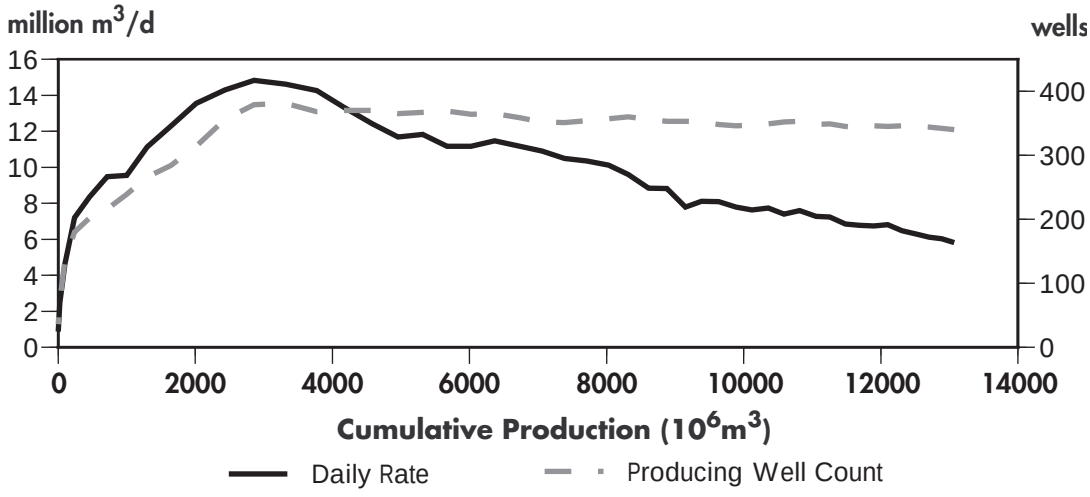


Production Rate versus Cumulative Production by Area for 1996 Connections

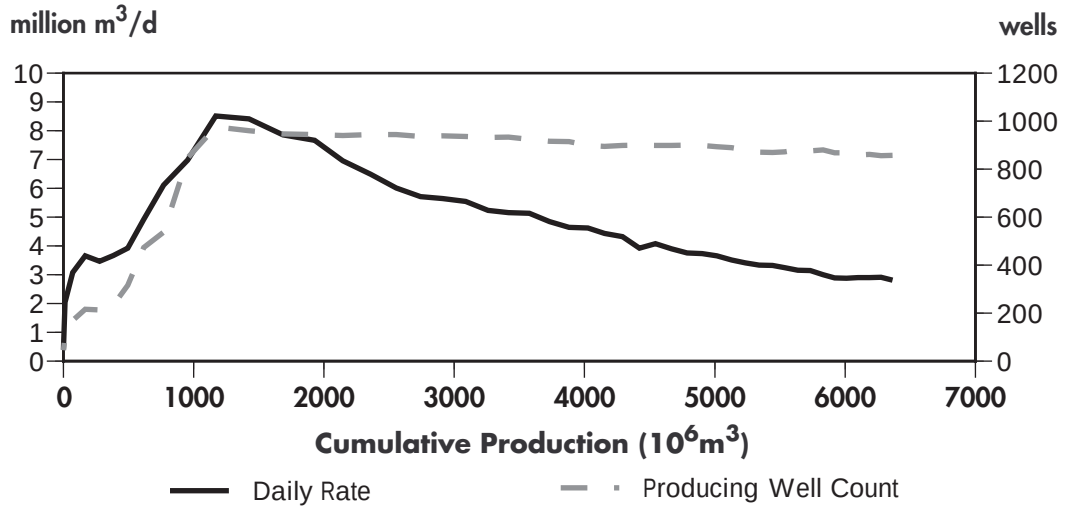
A L B E R T A F O O T H I L L S



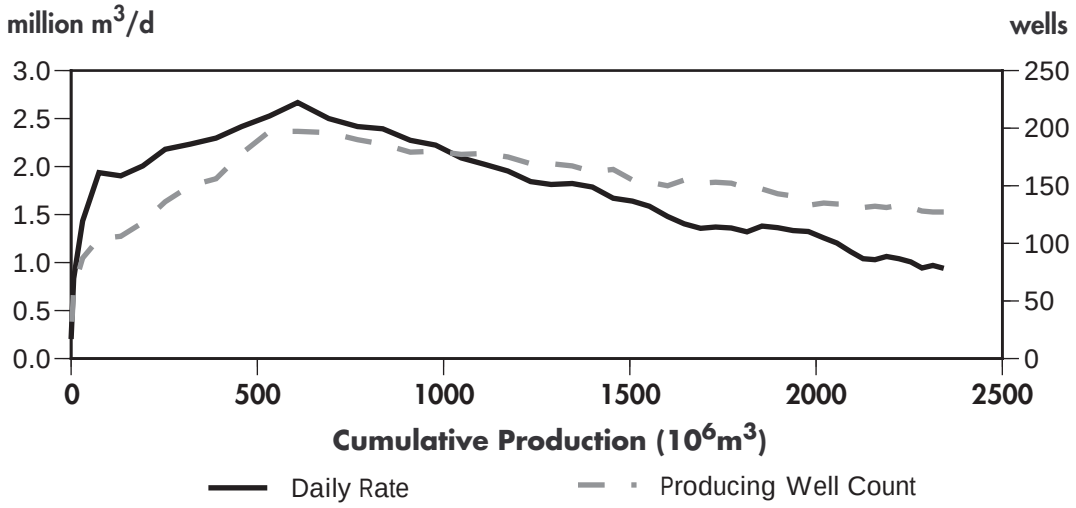
A L B E R T A F O O T H I L L S F R O N T



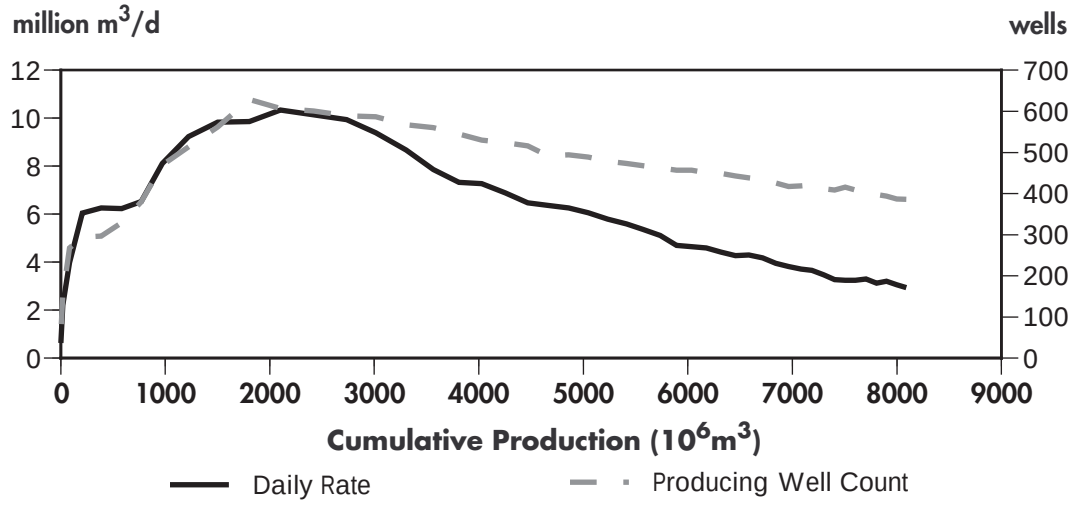
ALBERTA SOUTHEAST



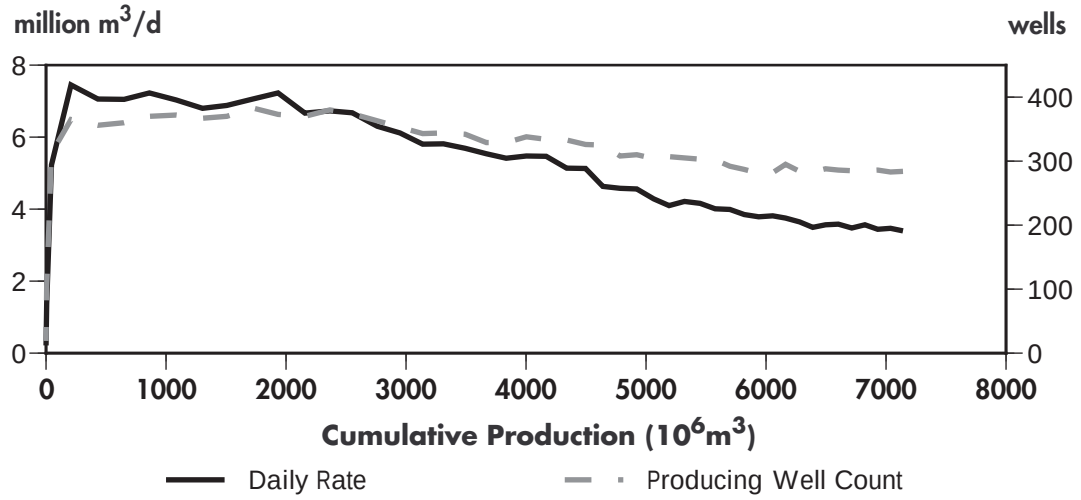
ALBERTA EAST



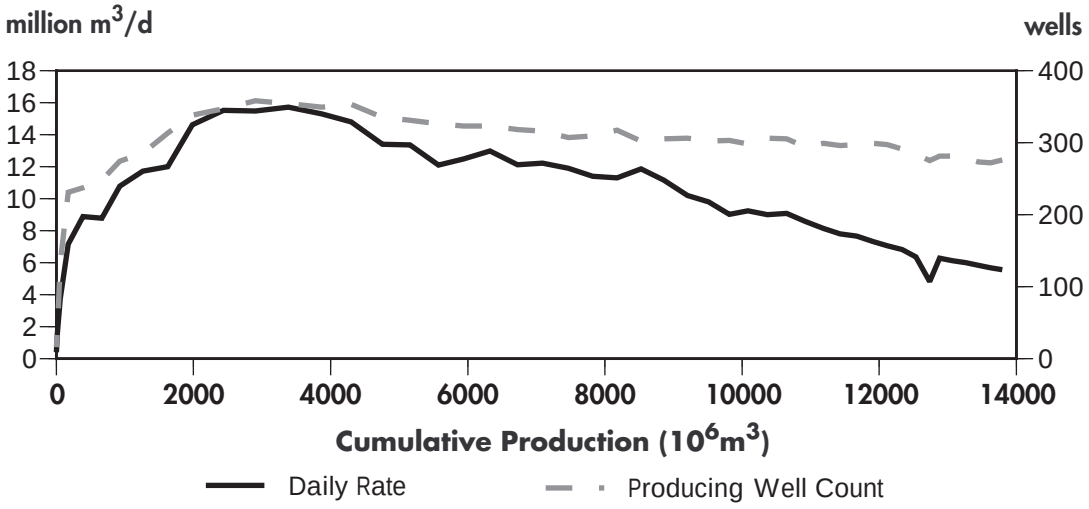
ALBERTA CENTRAL



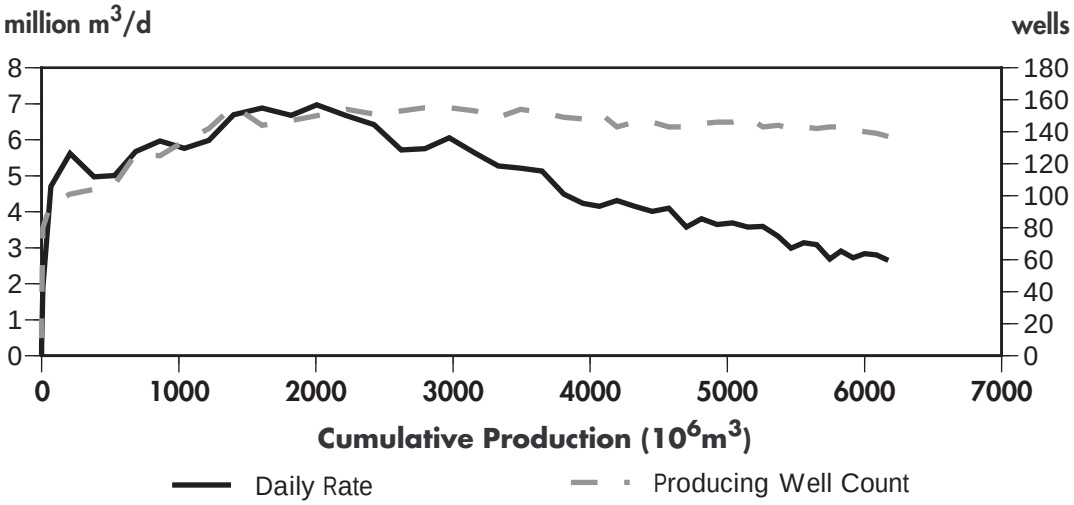
ALBERTA NORTHEAST



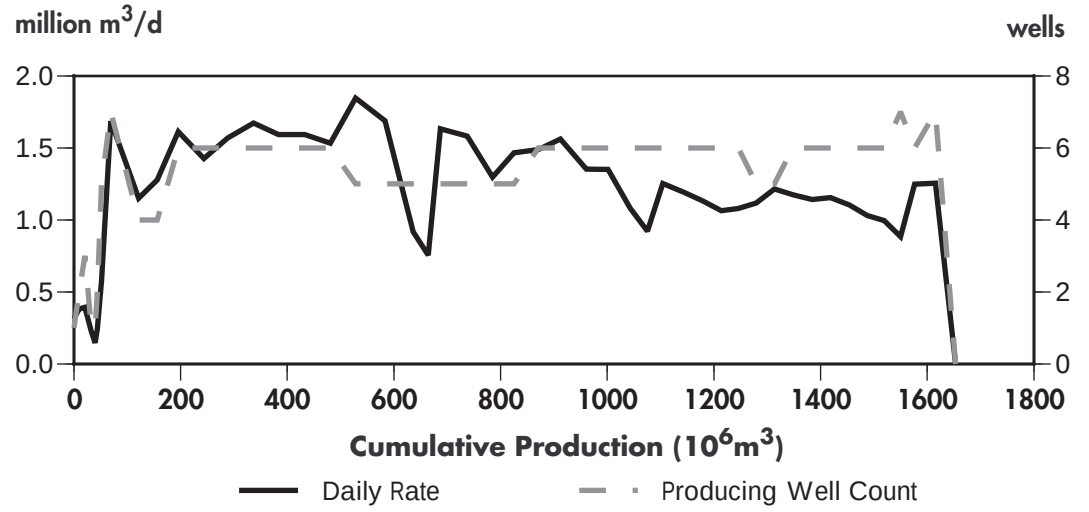
ALBERTA NORTHWEST



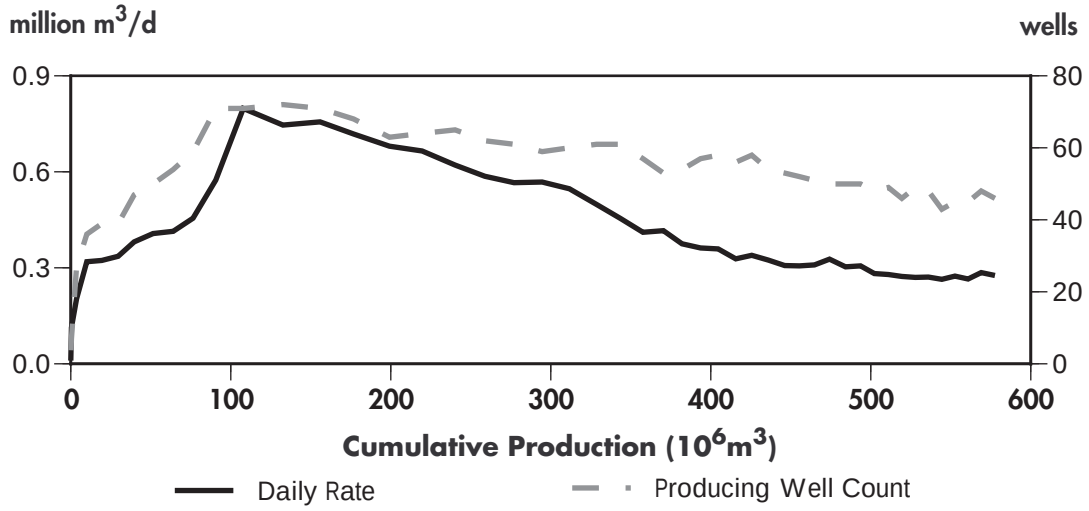
BC PLAINS



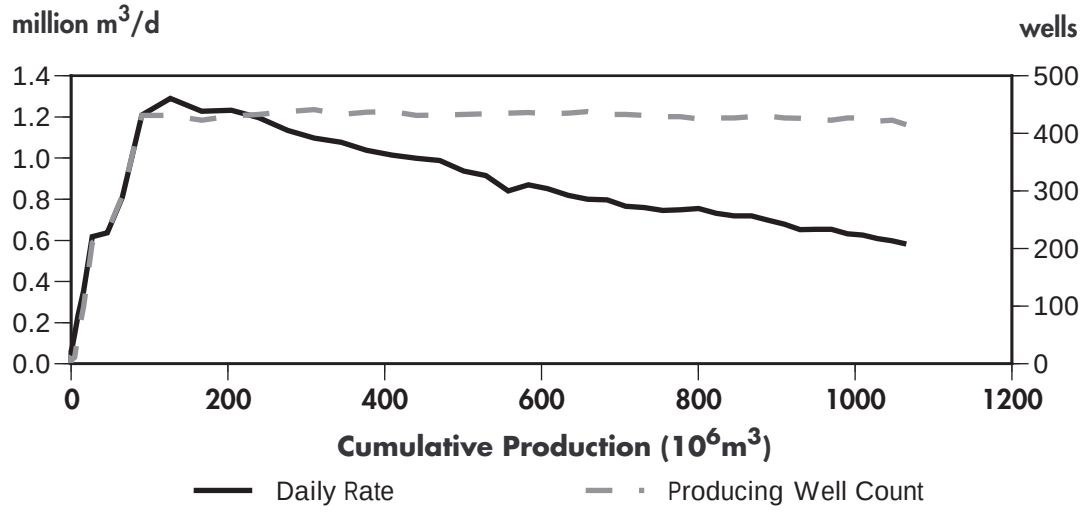
BC FOOTHILLS



SASKATCHEWAN WEST CENTRAL

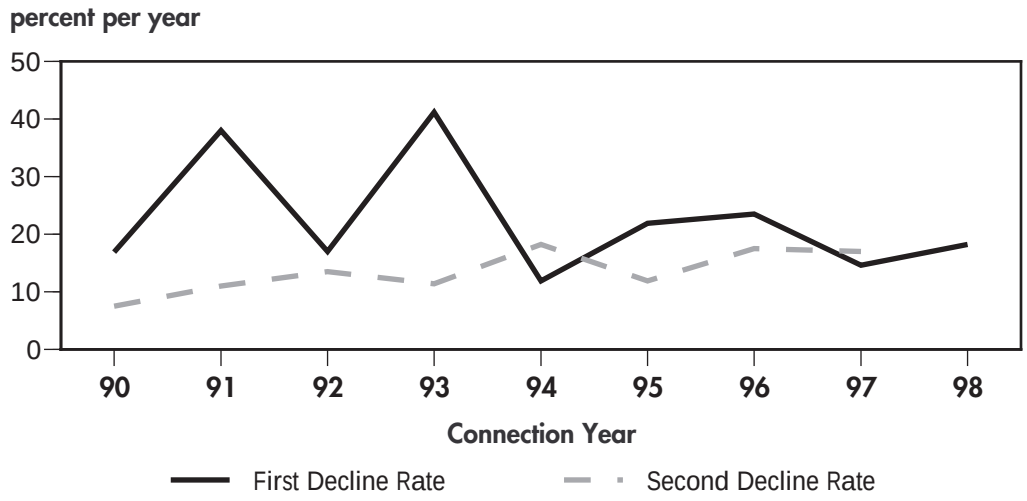


SASKATCHEWAN SOUTHWEST

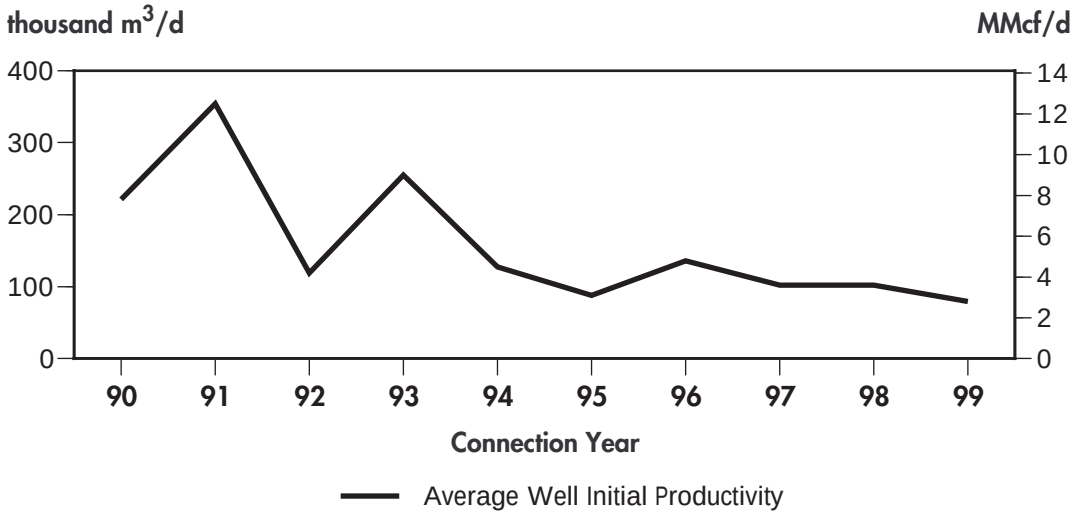


Decline Rates and Initial Productivities

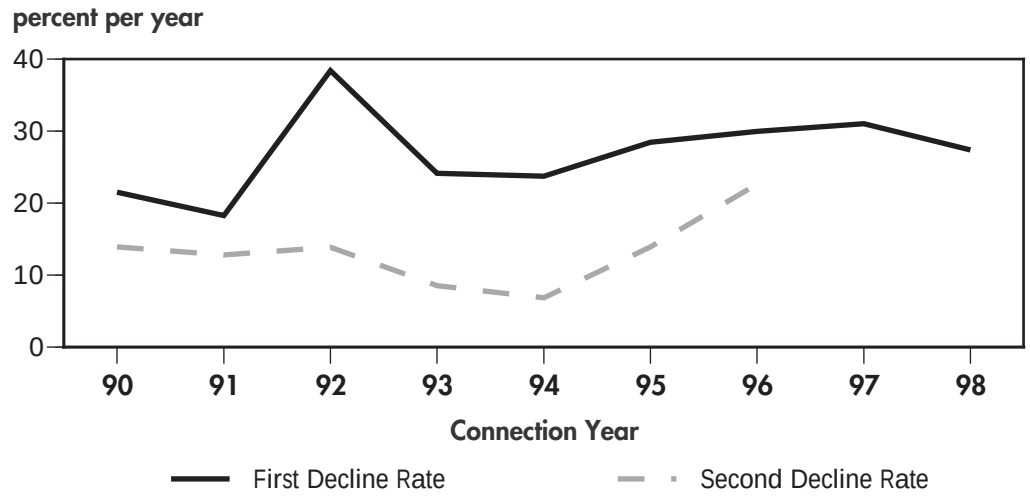
ALBERTA FOOTHILLS — DECLINE RATES



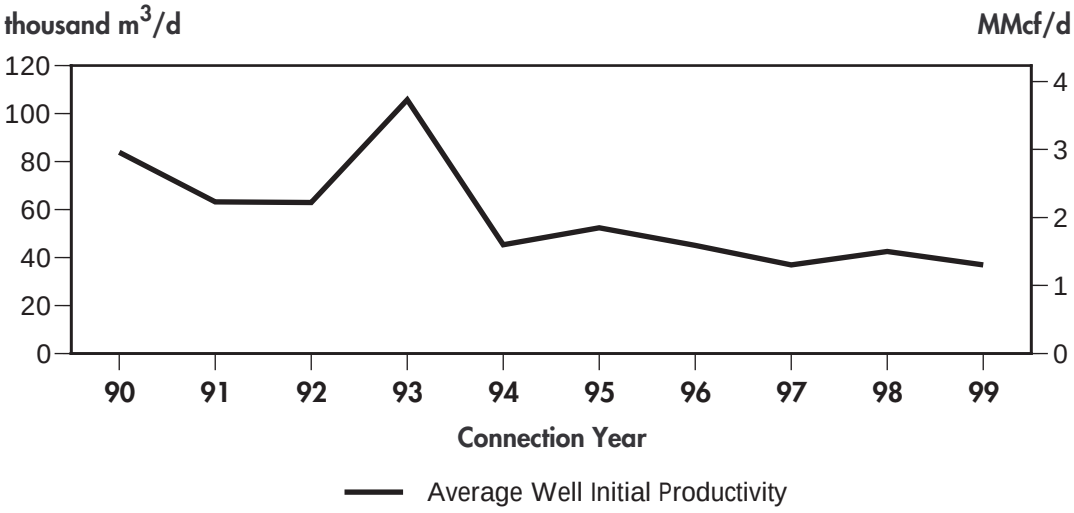
ALBERTA FOOTHILLS — INITIAL PRODUCTIVITIES



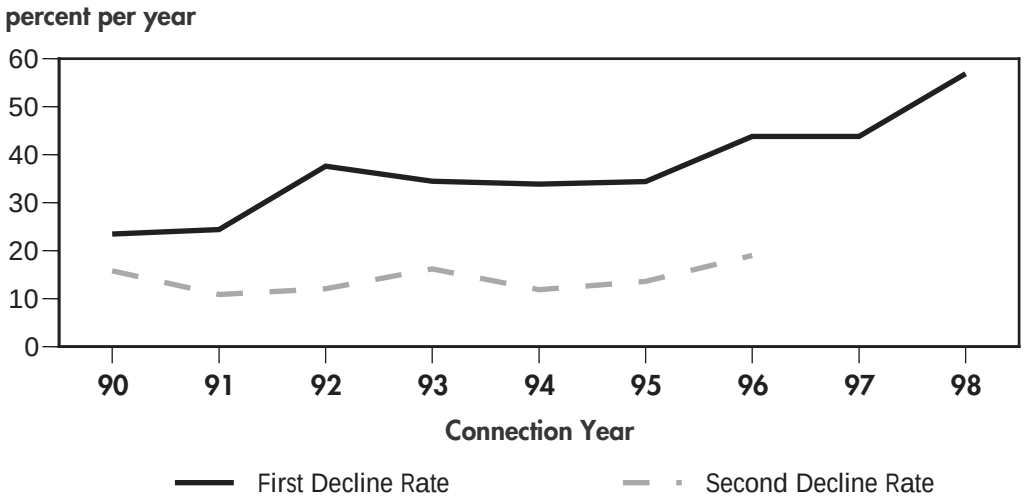
ALBERTA FOOTHILLS FRONT — DECLINE RATES



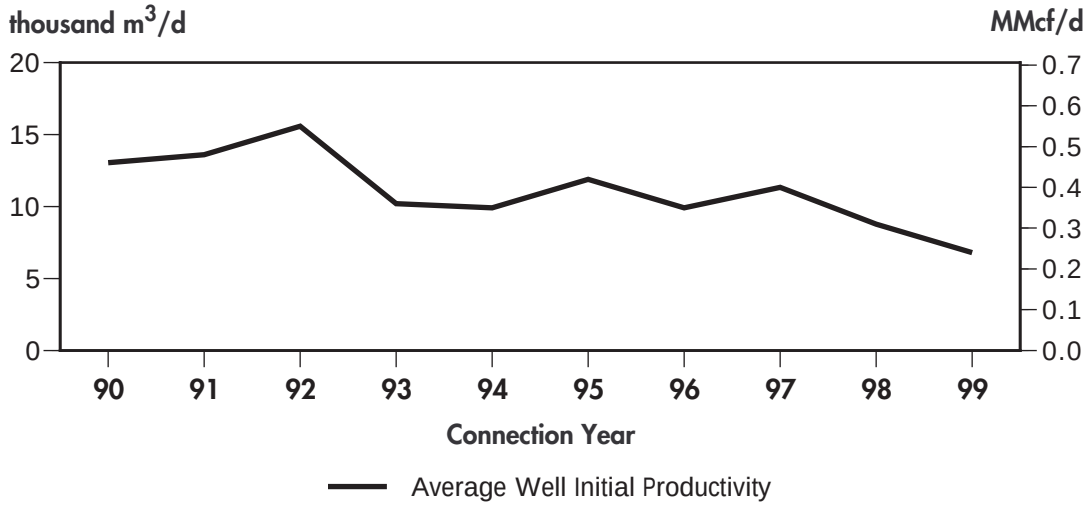
ALBERTA FOOTHILLS FRONT — INITIAL PRODUCTIVITIES



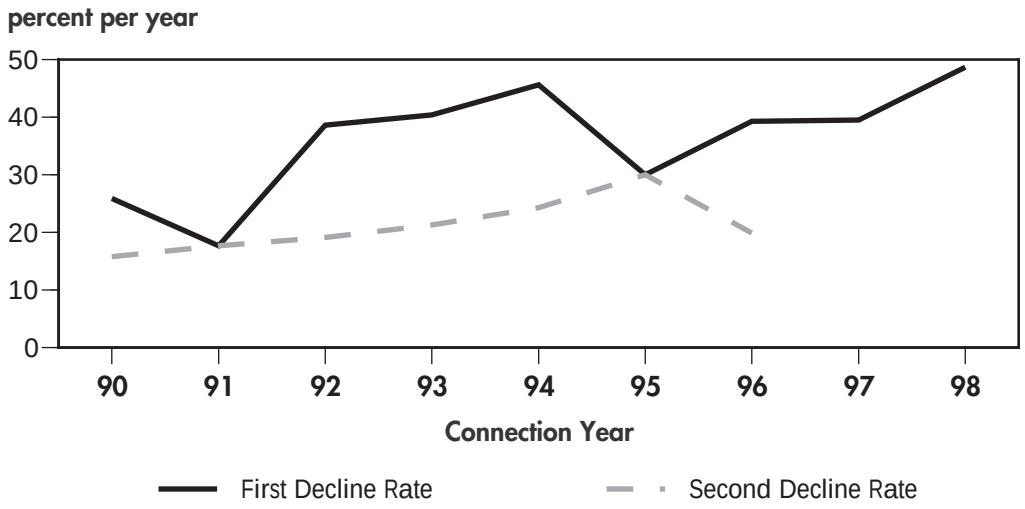
ALBERTA SOUTHEAST — DECLINE RATES



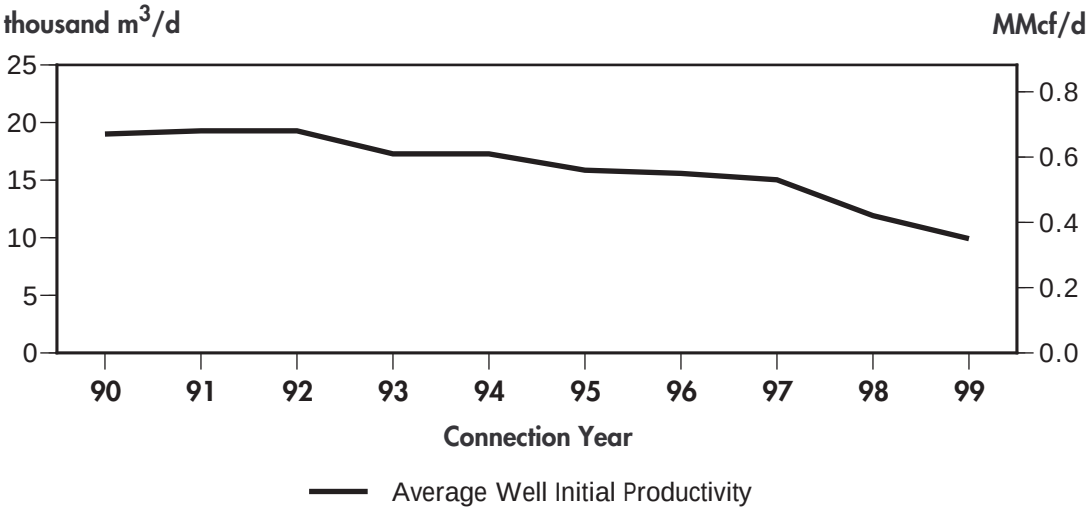
ALBERTA SOUTHEAST — INITIAL PRODUCTIVITIES



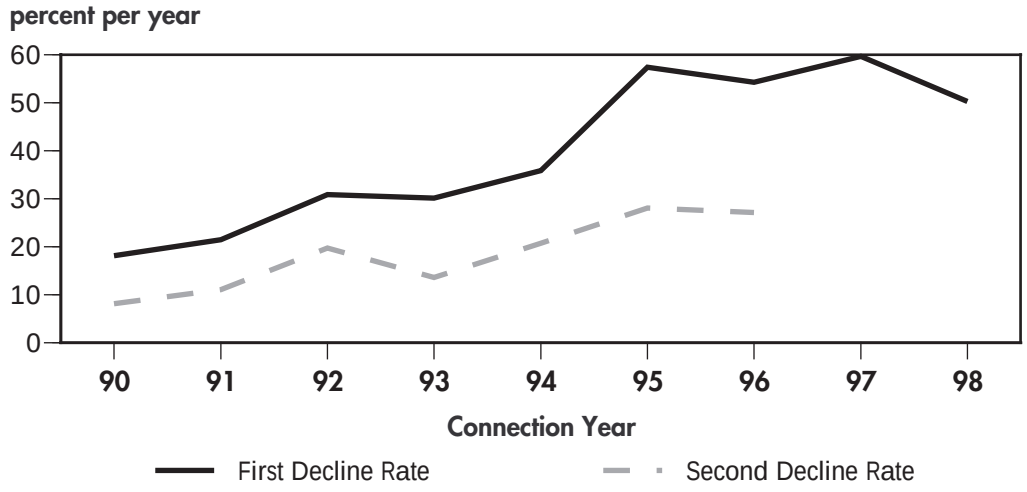
ALBERTA EAST — DECLINE RATES



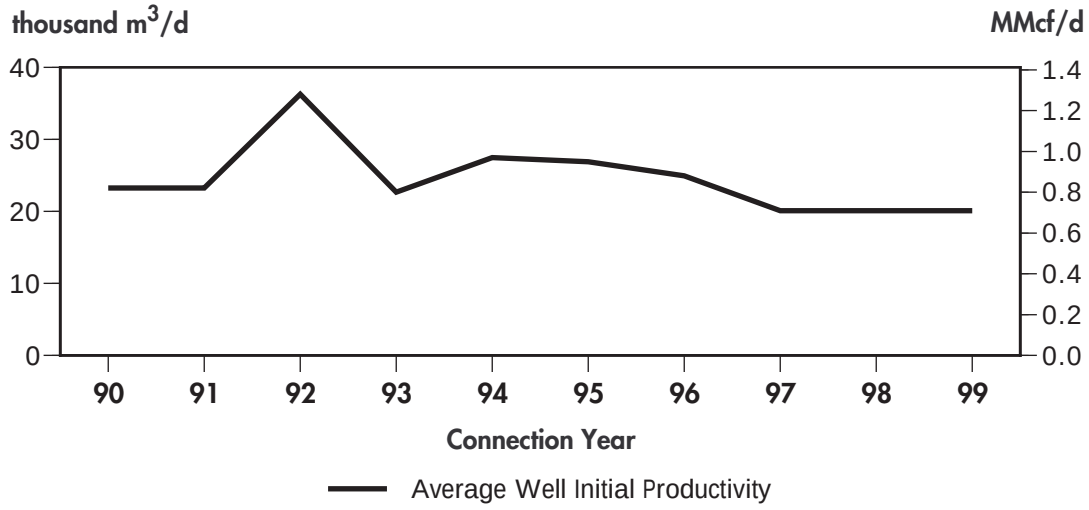
ALBERTA EAST — INITIAL PRODUCTIVITIES



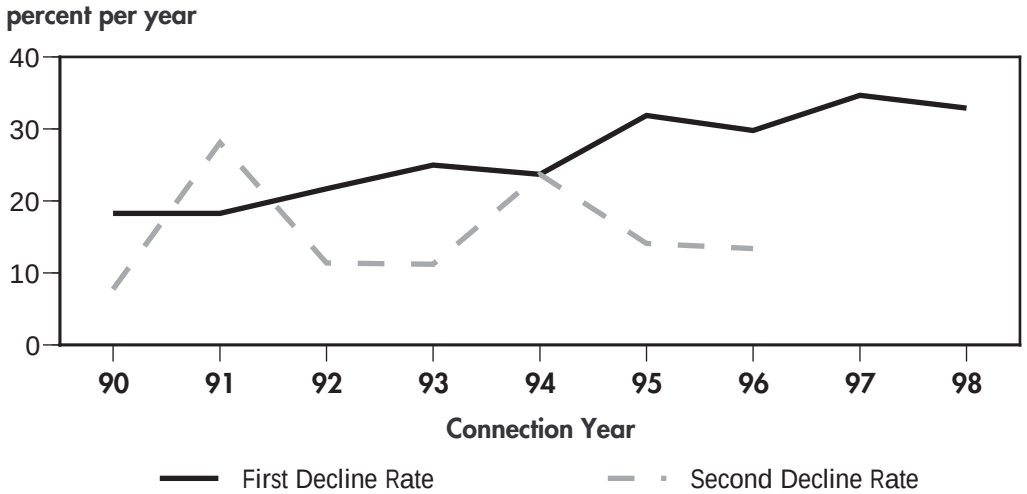
ALBERTA CENTRAL — DECLINE RATES



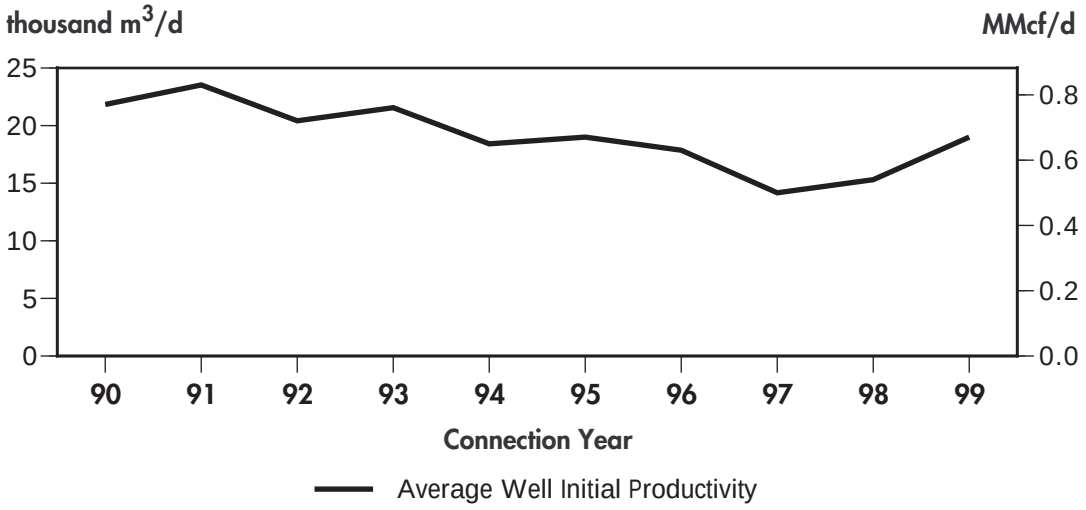
ALBERTA CENTRAL — INITIAL PRODUCTIVITIES



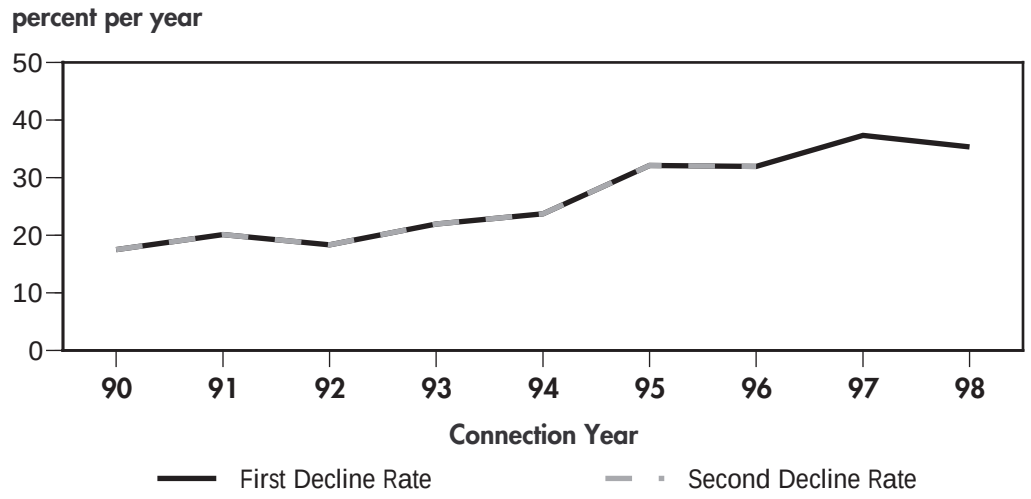
ALBERTA NORTHEAST — DECLINE RATES



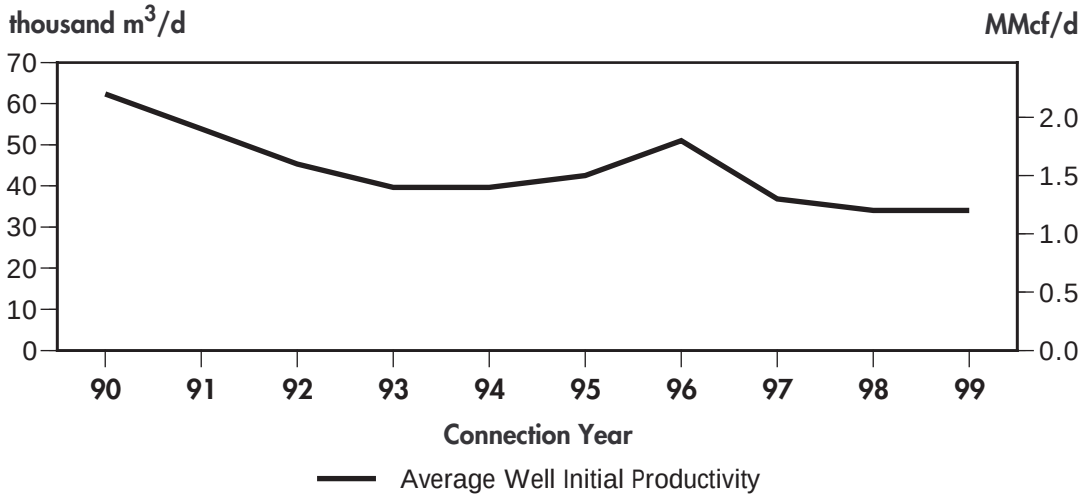
ALBERTA NORTHEAST — INITIAL PRODUCTIVITIES



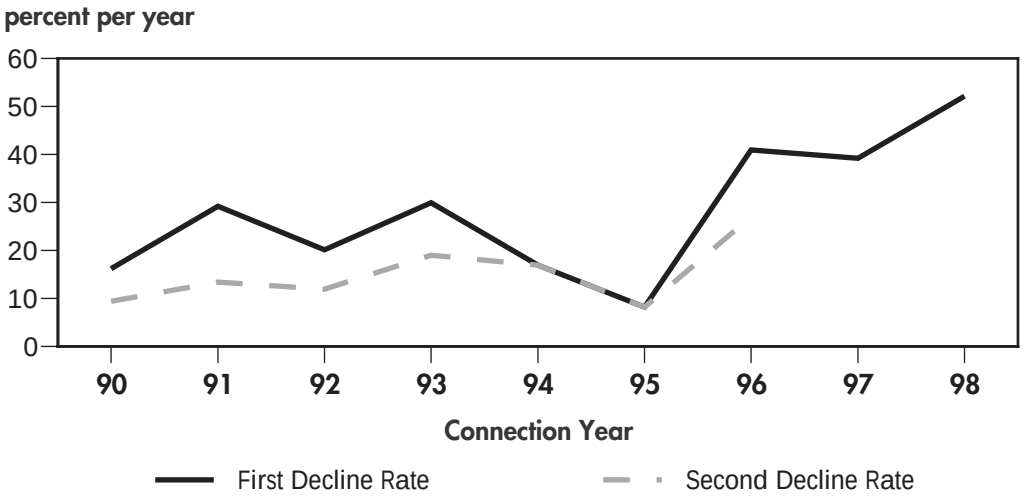
ALBERTA NORTHWEST — DECLINE RATES



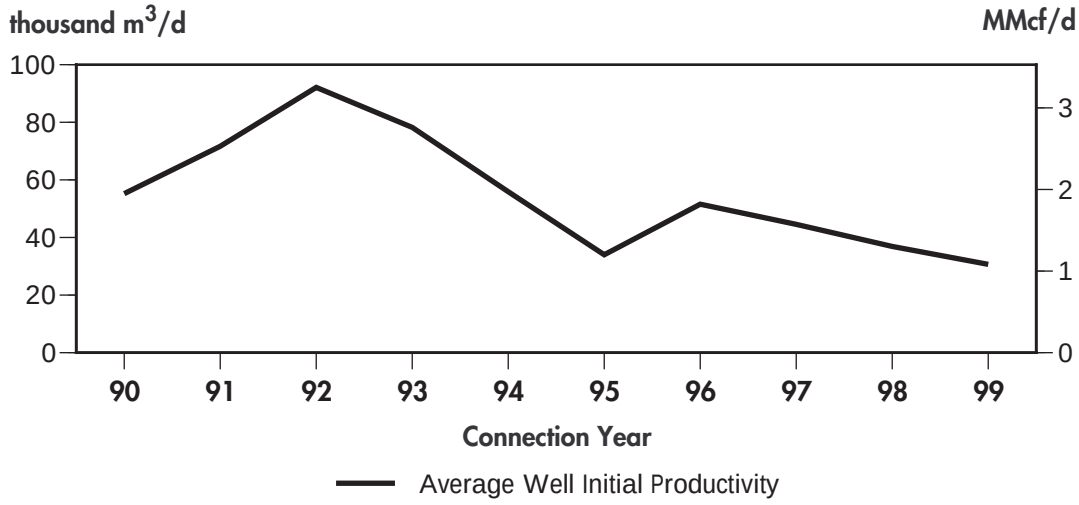
ALBERTA NORTHWEST — INITIAL PRODUCTIVITIES



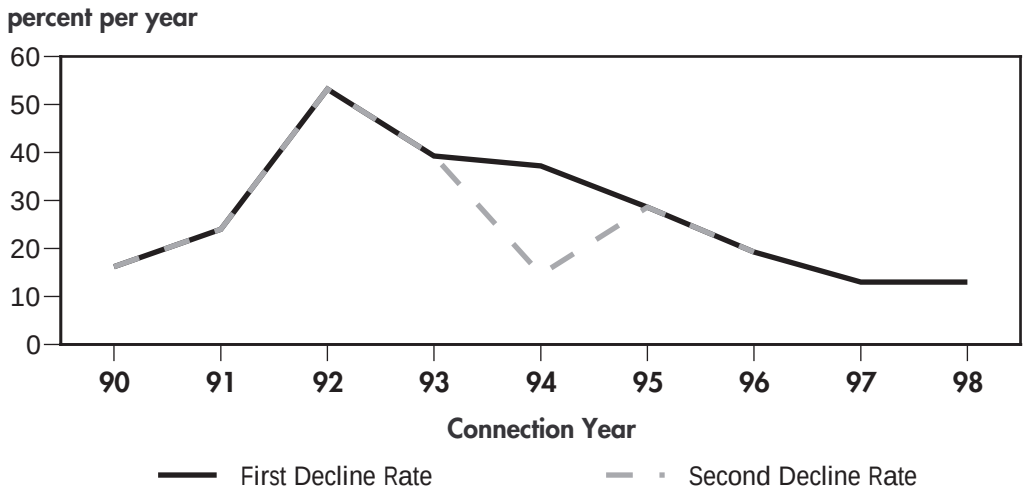
BC PLAINS — DECLINE RATES



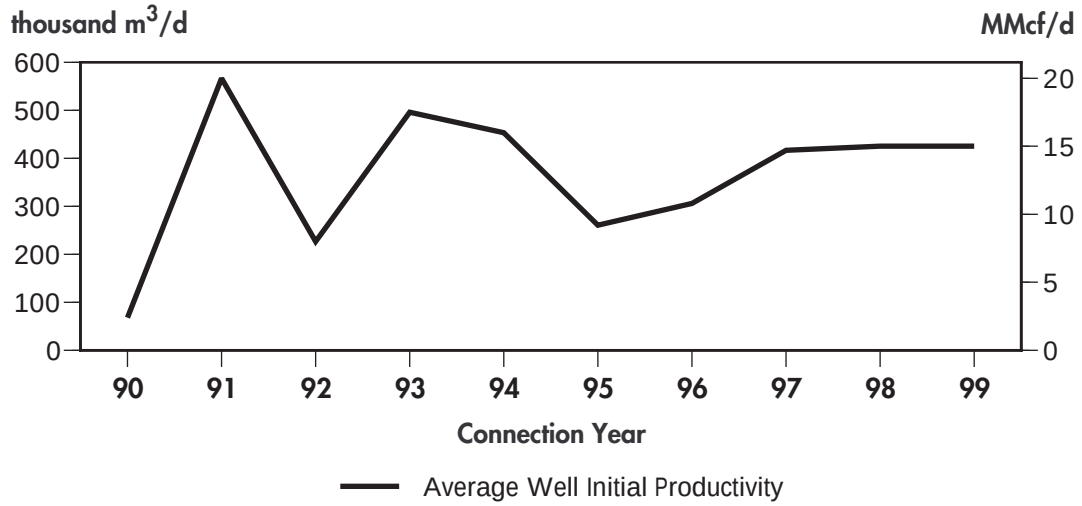
BC PLAINS — INITIAL PRODUCTIVITIES



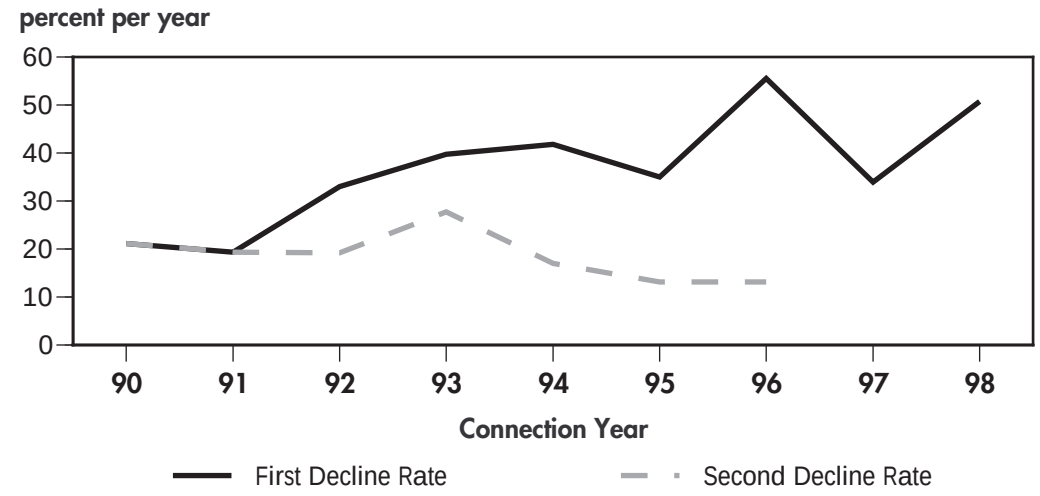
BC FOOTHILLS — DECLINE RATES



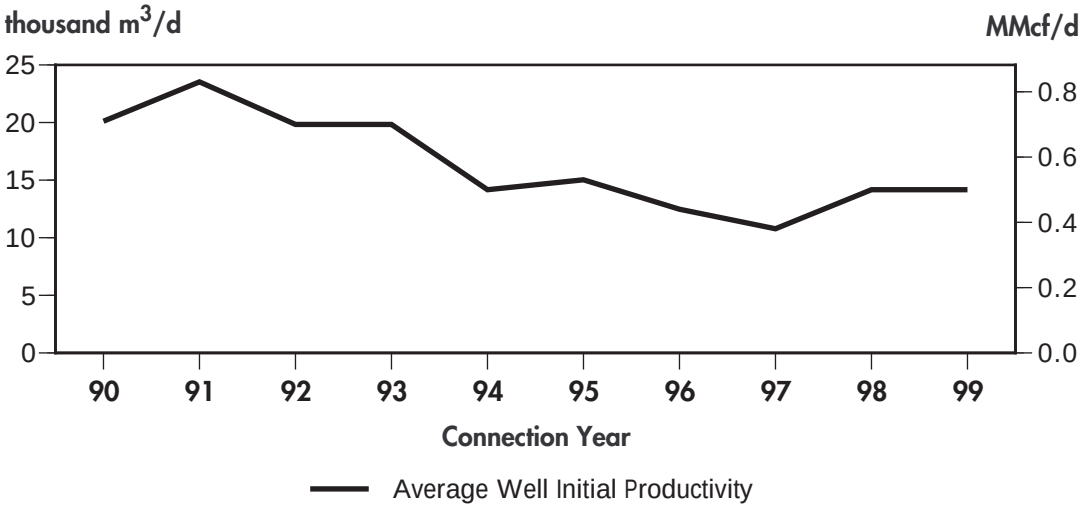
BC FOOTHILLS — INITIAL PRODUCTIVITIES



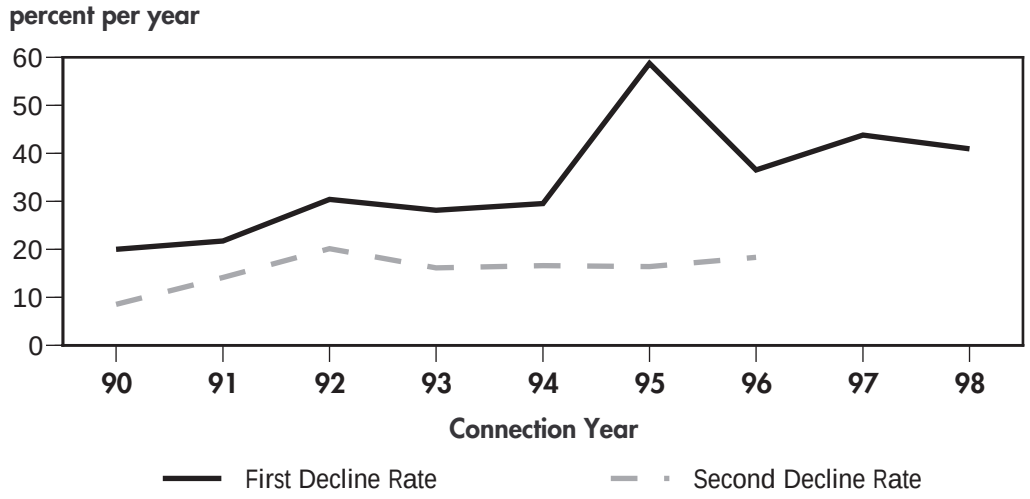
SASKATCHEWAN WEST CENTRAL — DECLINE RATES



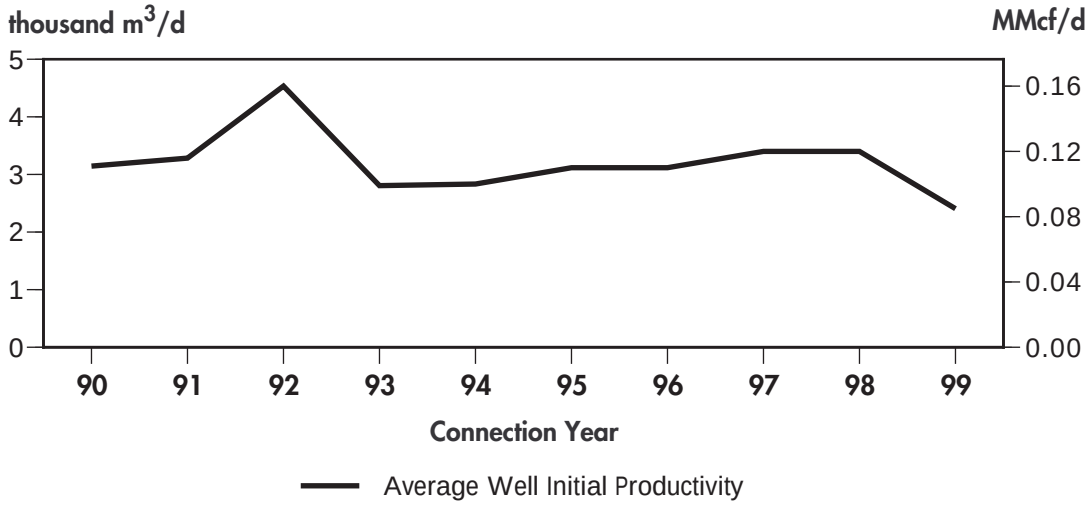
SASKATCHEWAN WEST CENTRAL — INITIAL PRODUCTIVITIES



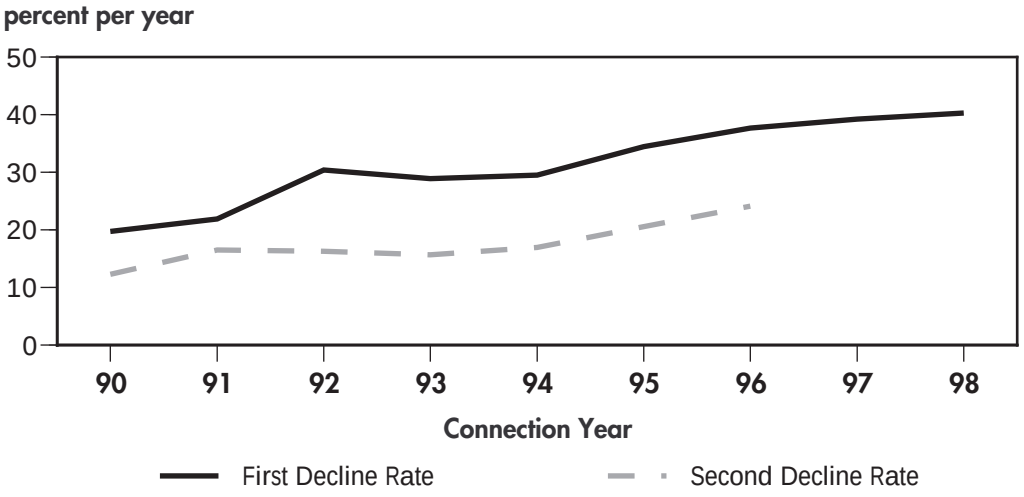
SASKATCHEWAN SOUTHWEST — DECLINE RATES



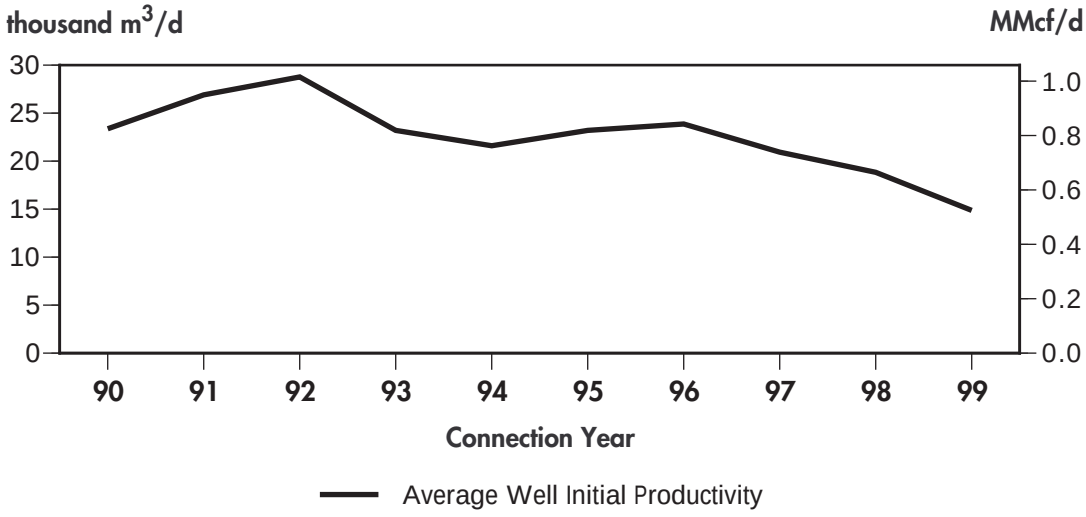
SASKATCHEWAN SOUTHWEST — INITIAL PRODUCTIVITIES



WCSB — DECLINE RATES



WCSB — INITIAL PRODUCTIVITIES

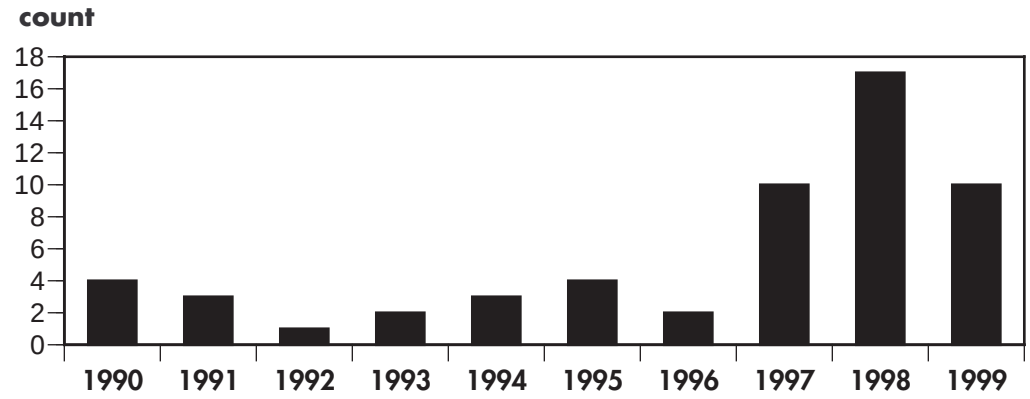


Drilling Statistics by Area

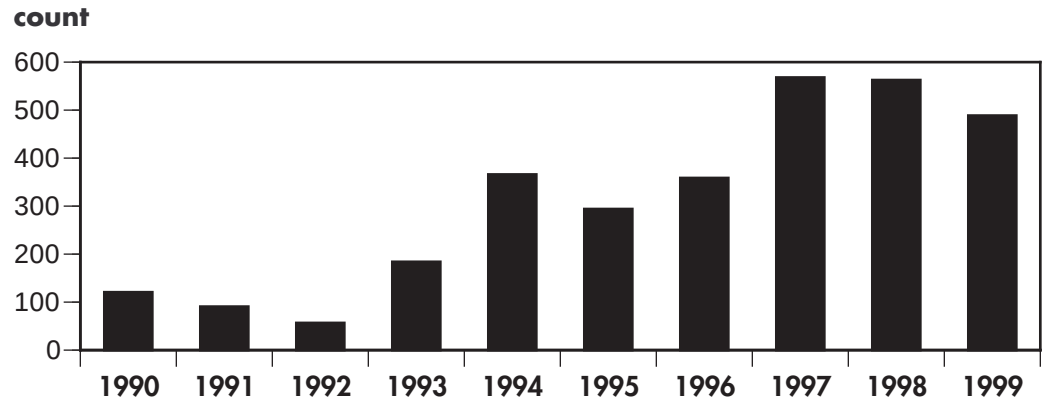
TYPICAL GAS WELL DRILLING COSTS BY AREA

Province	Area	Typical Gas Well Drilling Costs Thousand Dollars
Alberta	Foothills	2500
	Foothills Front	1000
	Southeast	60
	East	225
	Central	350
	Northeast	200
	Northwest	500
BC	Plains	600
	Foothills	5000
Saskatchewan	West Central	225
	Southwest	60

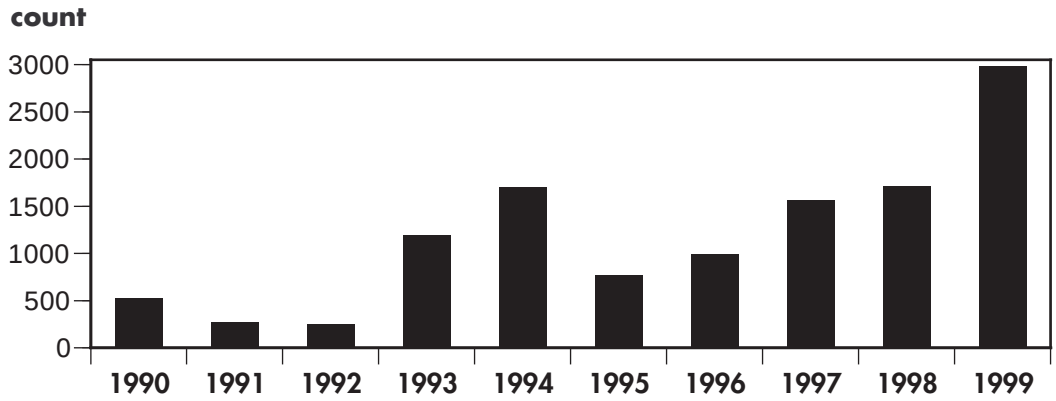
ALBERTA FOOTHILLS — GAS WELL COMPLETIONS



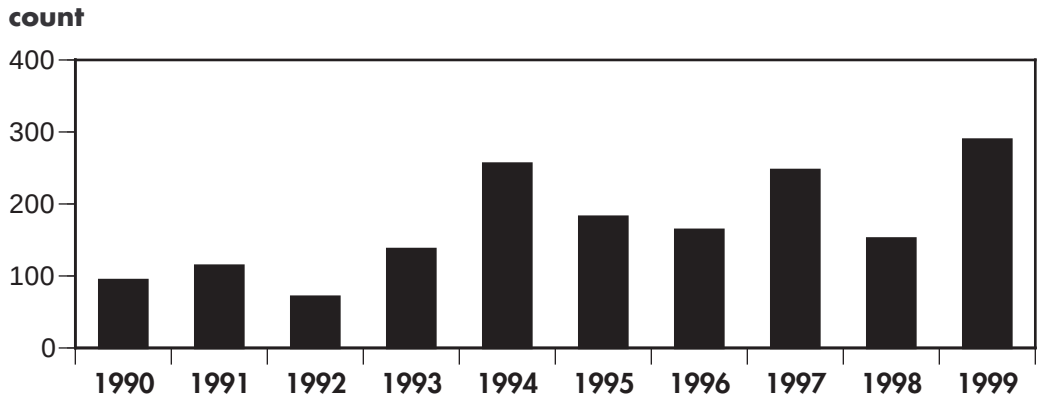
ALBERTA FOOTHILLS FRONT — GAS WELL COMPLETIONS



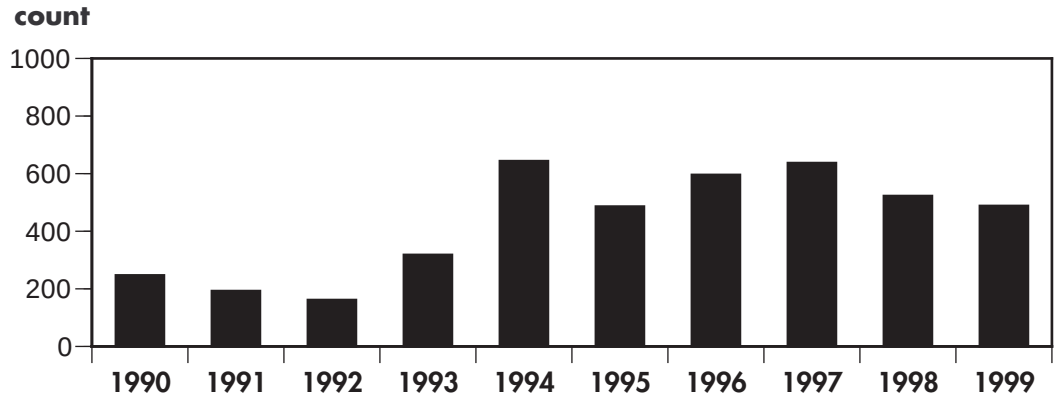
ALBERTA SOUTHEAST — GAS WELL COMPLETIONS



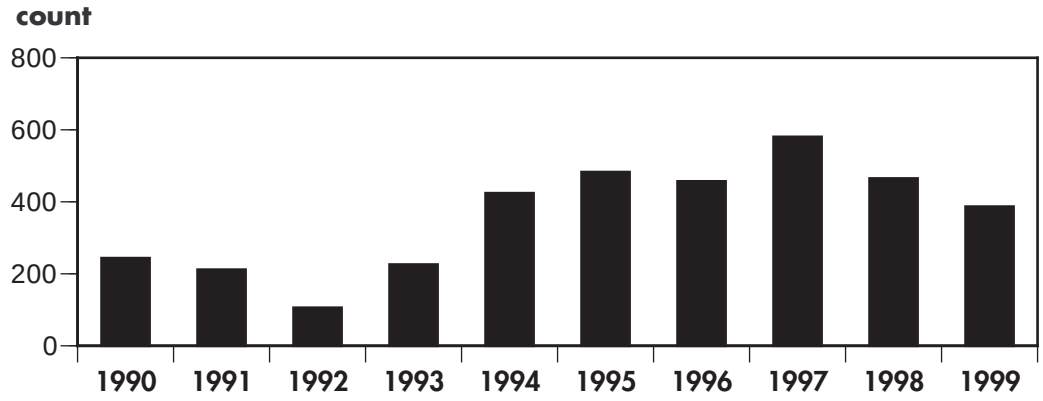
ALBERTA EAST — GAS WELL COMPLETIONS



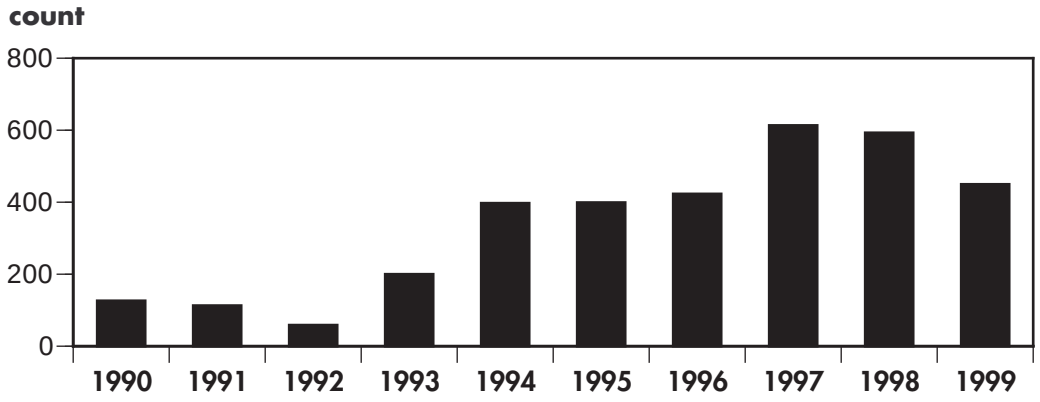
ALBERTA CENTRAL — GAS WELL COMPLETIONS



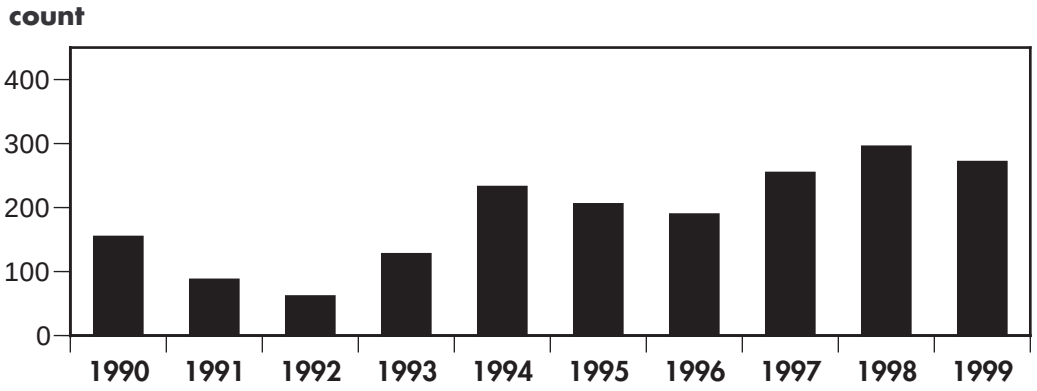
ALBERTA NORTHEAST — GAS WELL COMPLETIONS



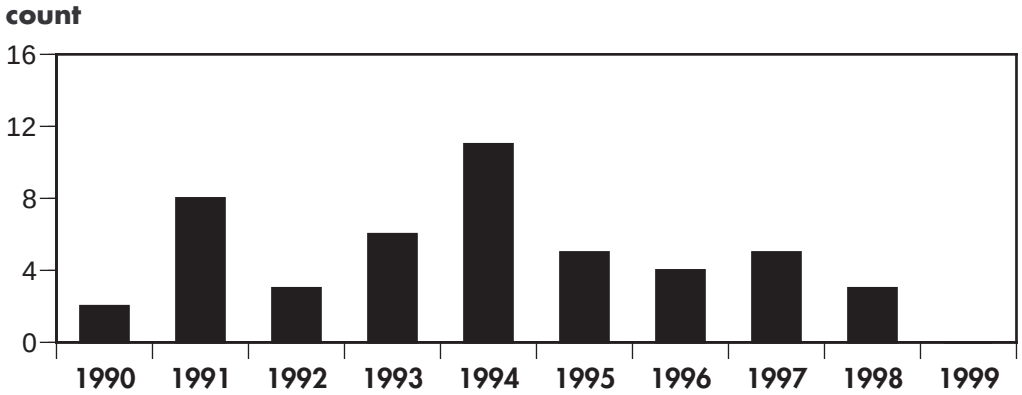
ALBERTA NORTHWEST — GAS WELL COMPLETIONS



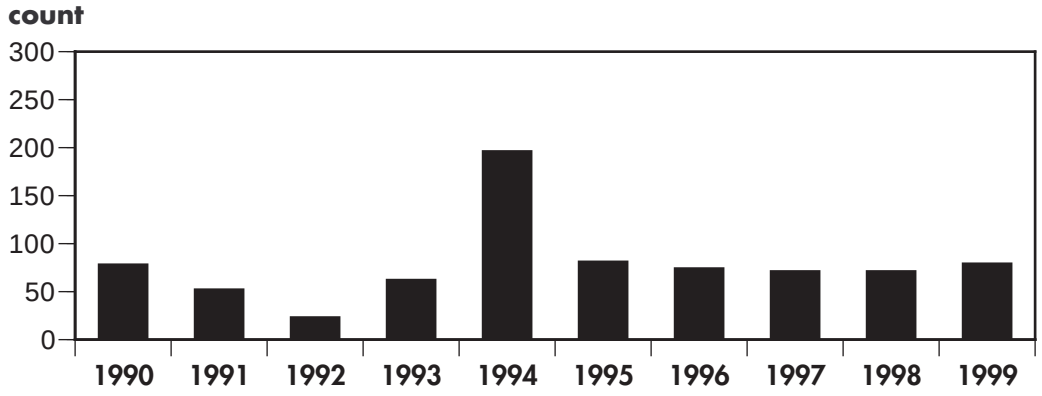
BC PLAINS — GAS WELL COMPLETIONS



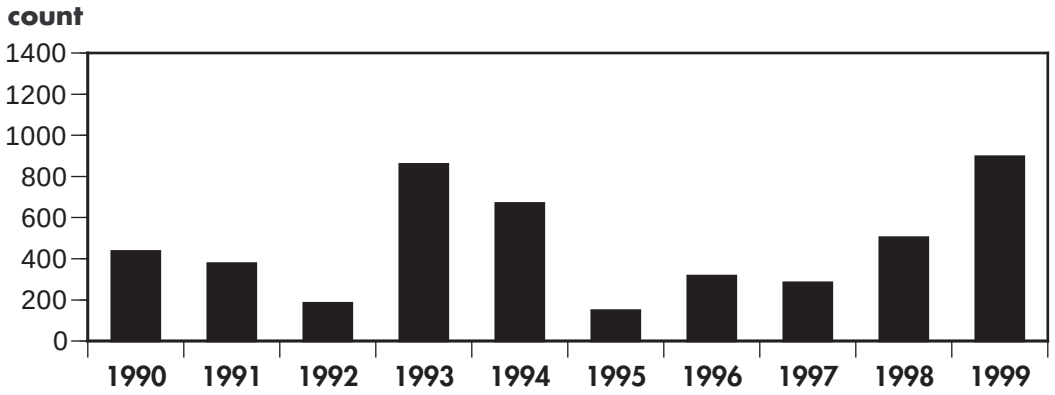
BC FOOTHILLS — GAS WELL COMPLETIONS



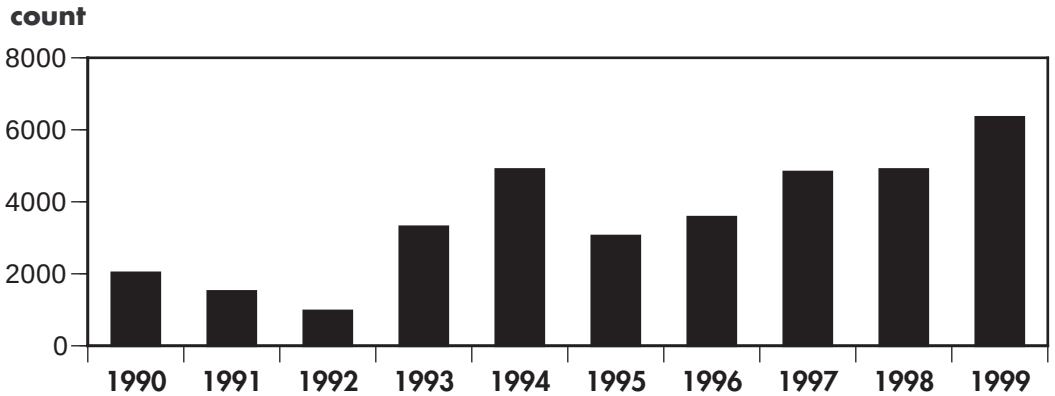
SASKATCHEWAN WEST CENTRAL — GAS WELL COMPLETIONS



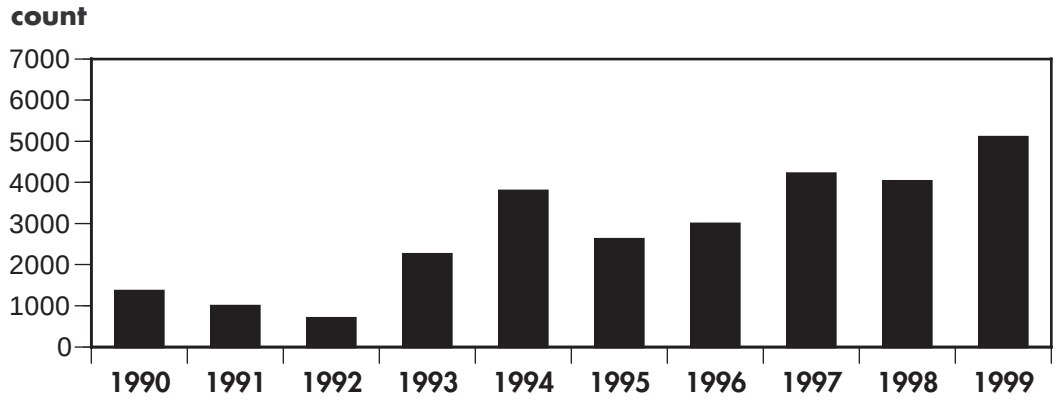
SASKATCHEWAN SOUTHWEST — GAS WELL COMPLETIONS



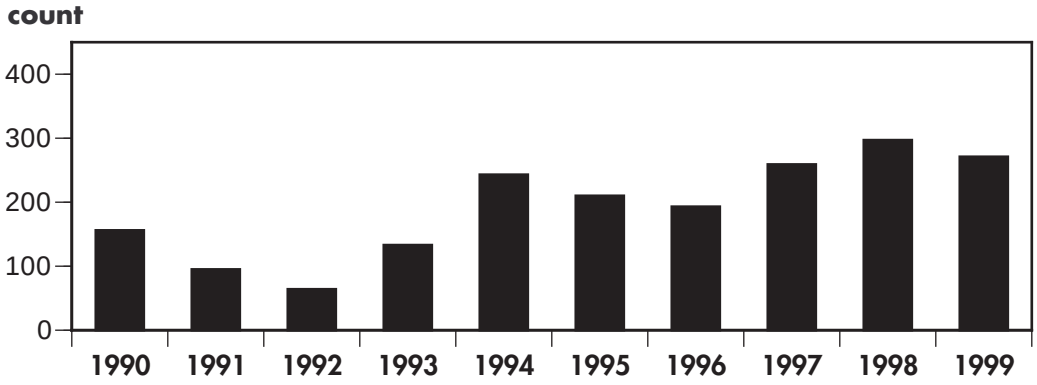
WCSB — GAS WELL COMPLETIONS



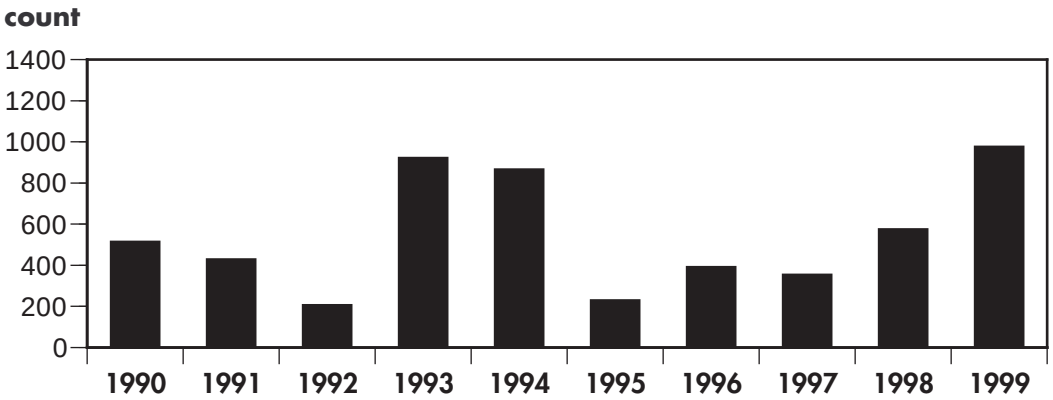
ALBERTA — GAS WELL COMPLETIONS



BC — GAS WELL COMPLETIONS

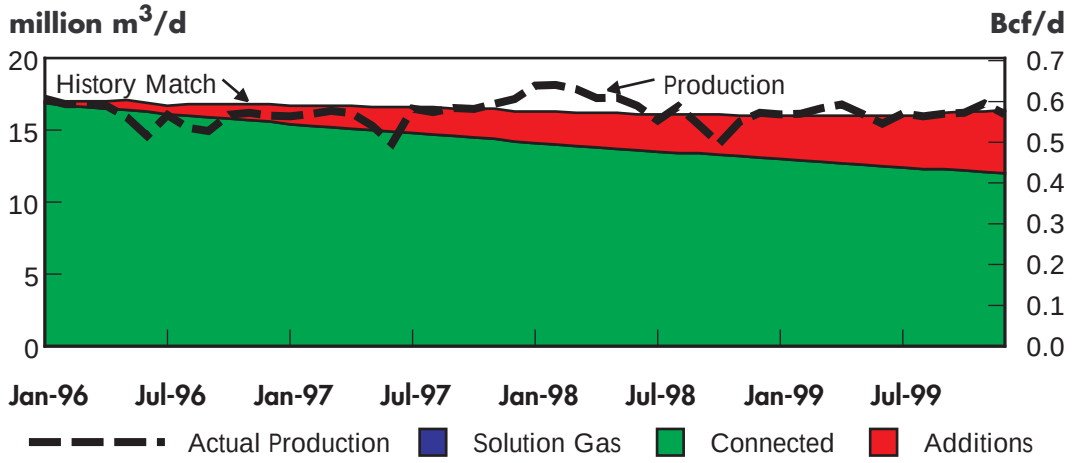


SASKATCHEWAN — GAS WELL COMPLETIONS

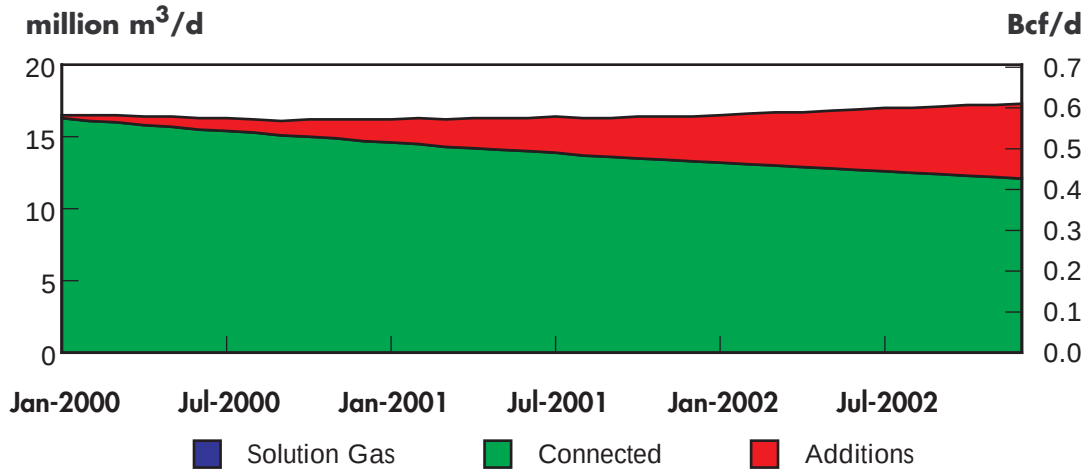


History Matches and Base Case Deliverability Forecasts

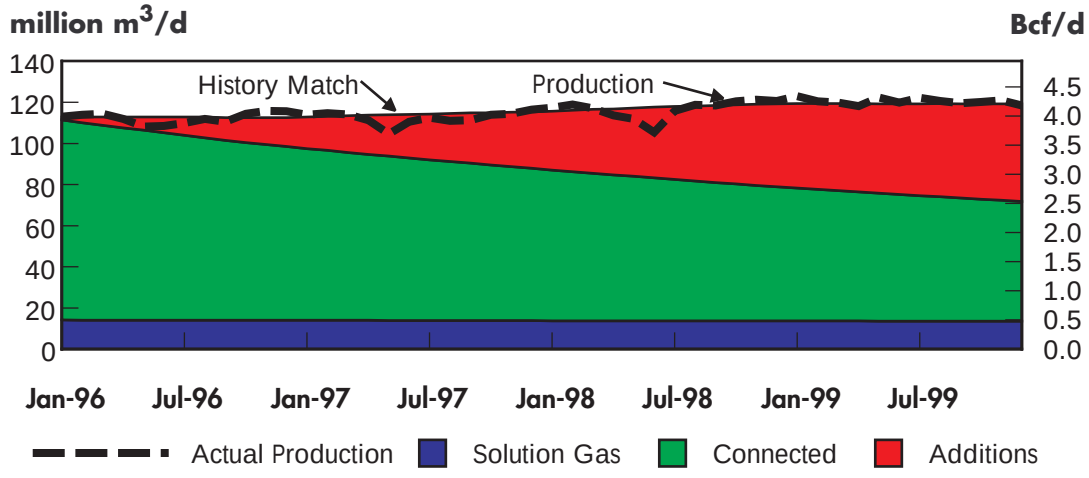
ALBERTA FOOTHILLS — HISTORY MATCH



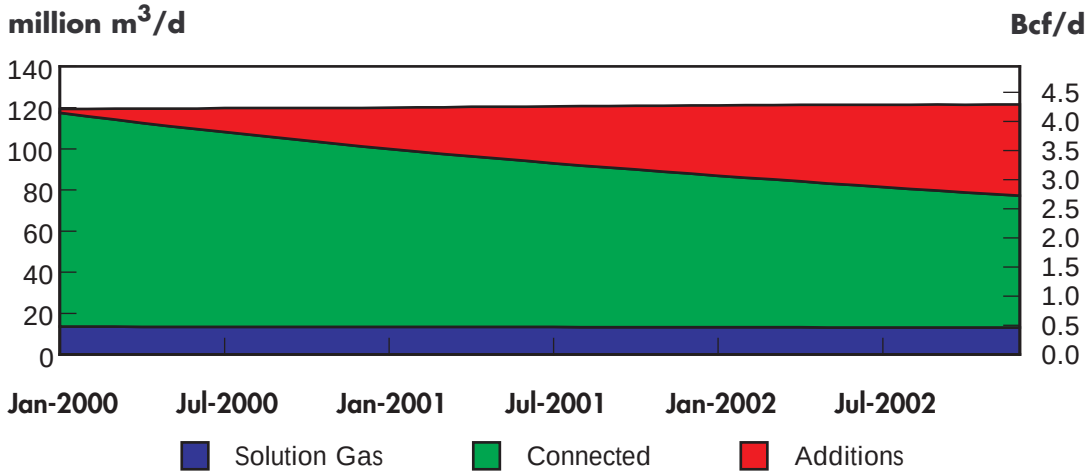
ALBERTA FOOTHILLS — BASE FORECAST



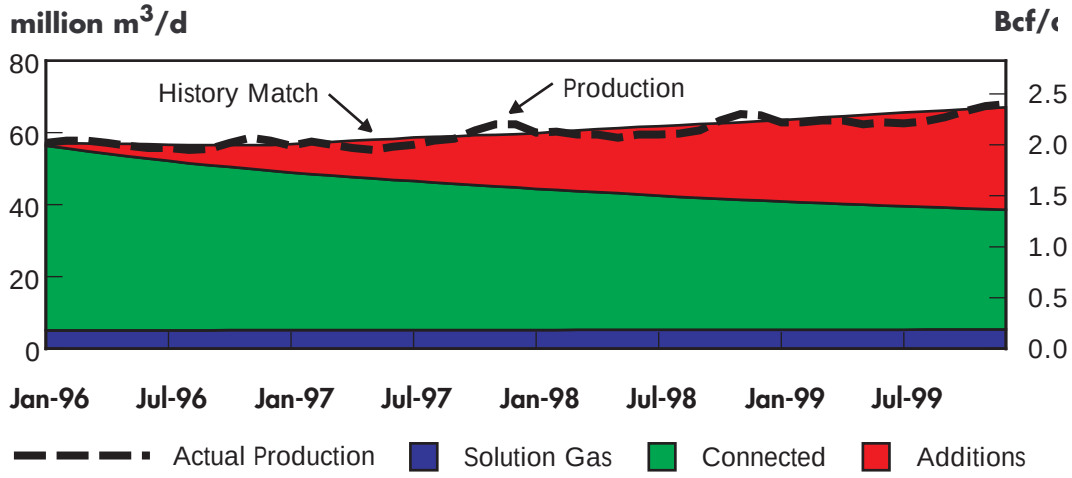
ALBERTA FOOTHILLS FRONT — HISTORY MATCH



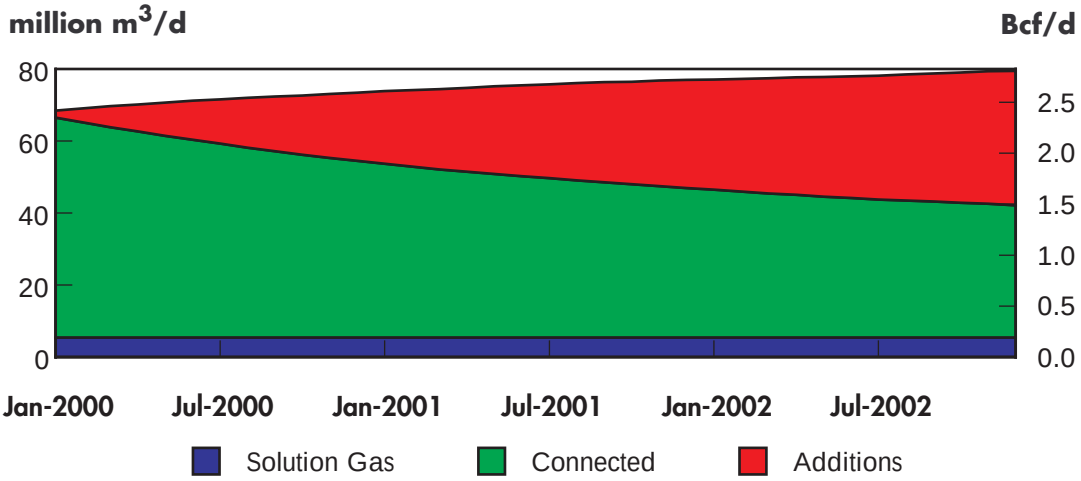
ALBERTA FOOTHILLS FRONT — BASE FORECAST



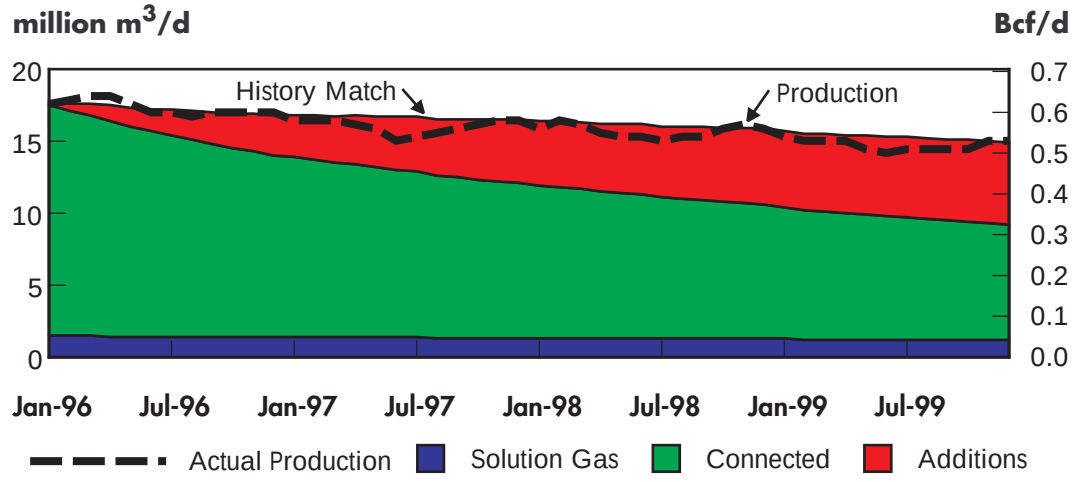
ALBERTA SOUTHEAST — HISTORY MATCH



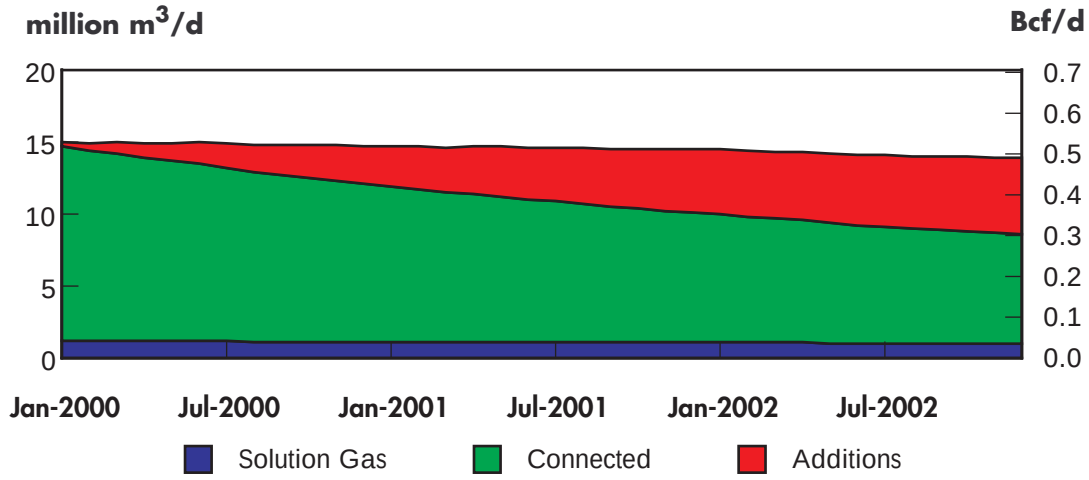
ALBERTA SOUTHEAST — BASE FORECAST



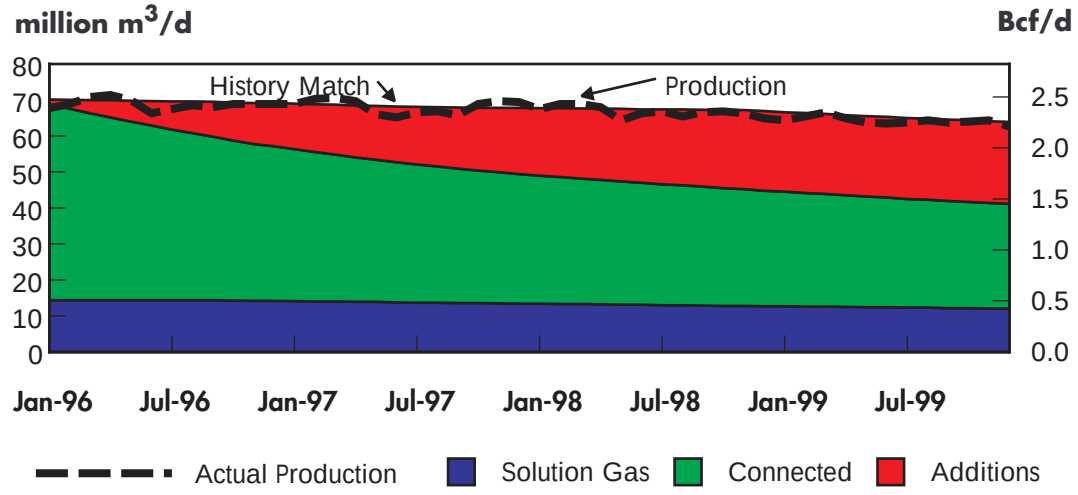
ALBERTA EAST — HISTORY MATCH



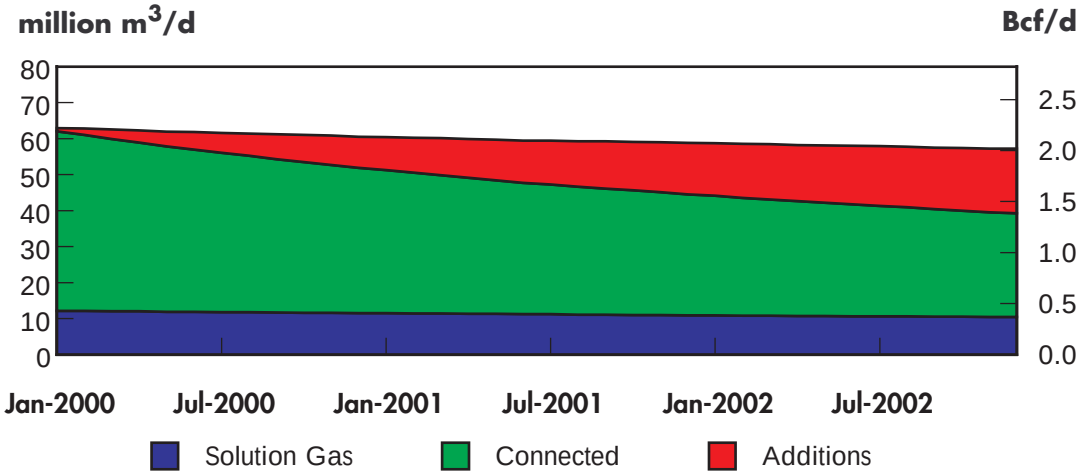
ALBERTA EAST — BASE FORECAST



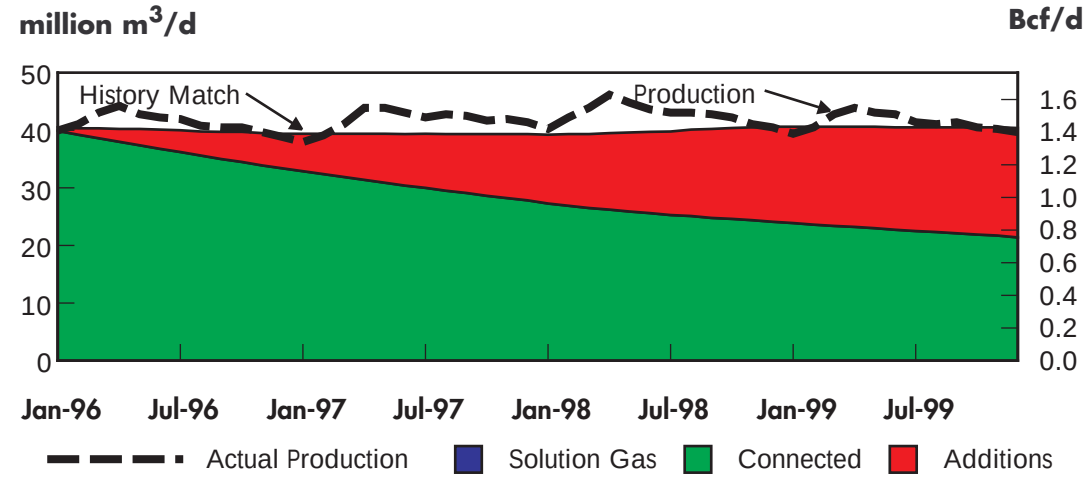
ALBERTA CENTRAL — HISTORY MATCH



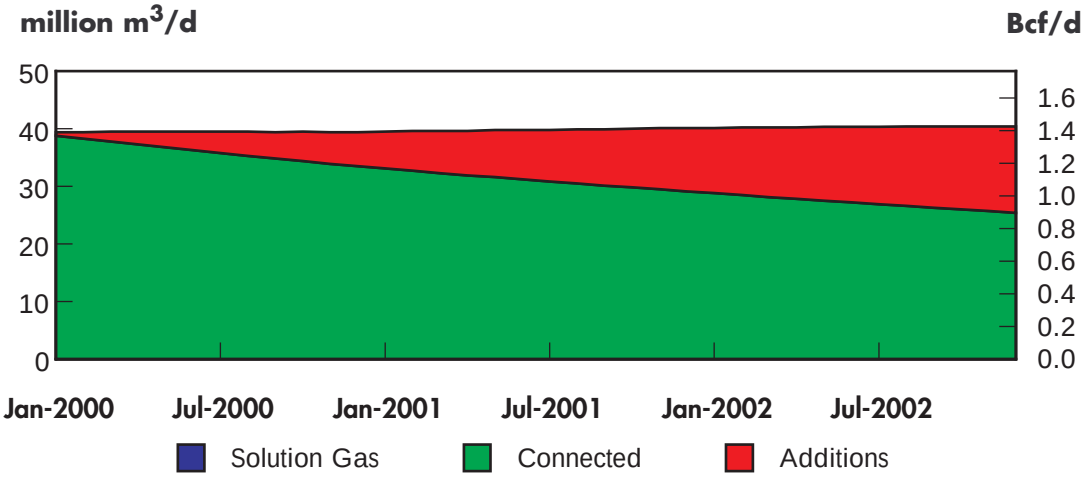
ALBERTA CENTRAL — BASE FORECAST



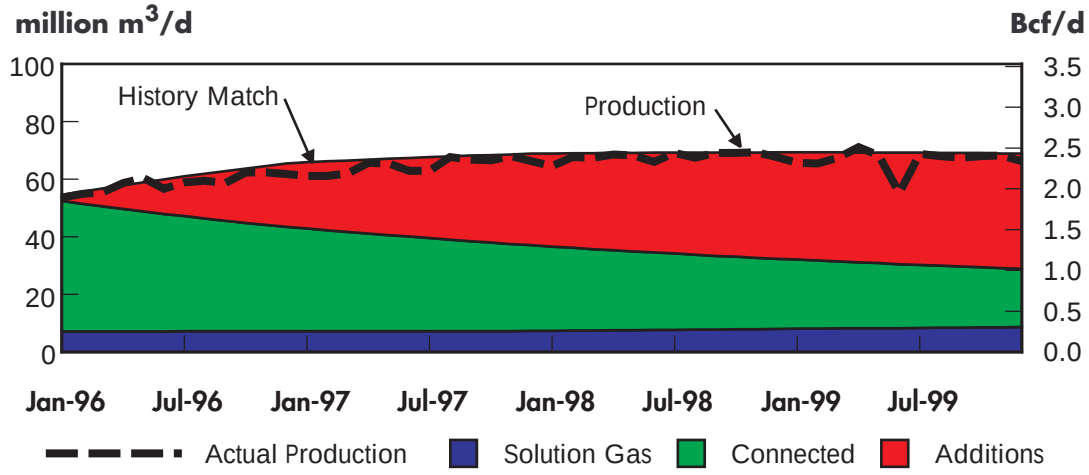
ALBERTA NORTHEAST — HISTORY MATCH



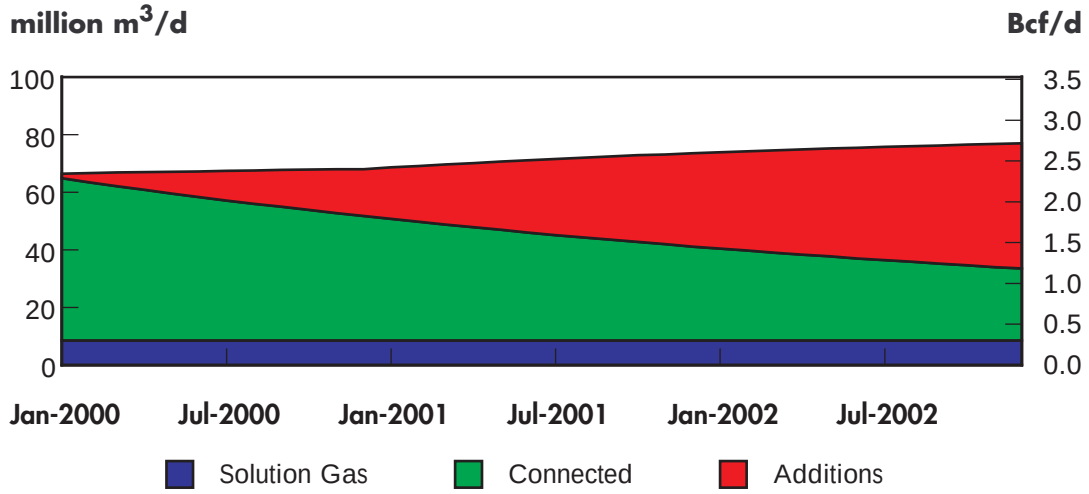
ALBERTA NORTHEAST — BASE FORECAST



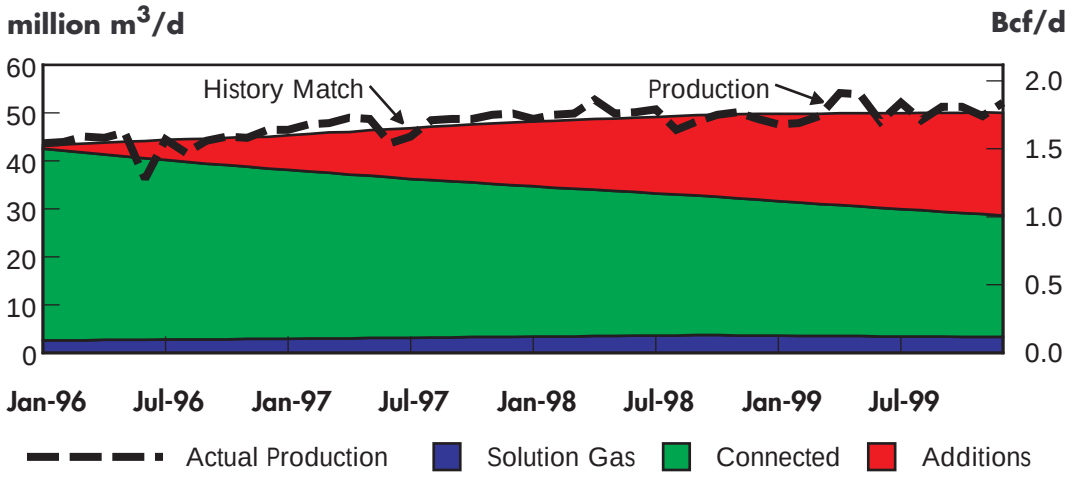
ALBERTA NORTHWEST — HISTORY MATCH



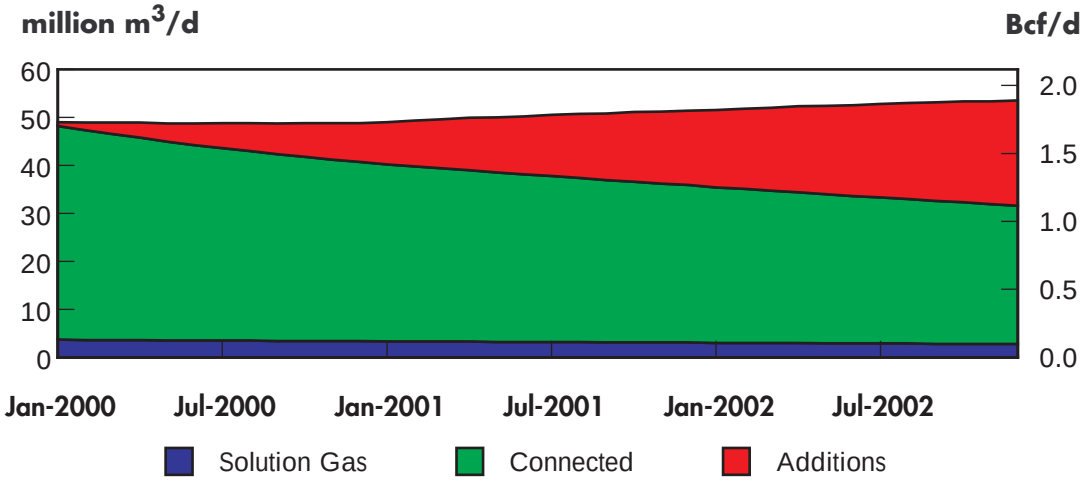
ALBERTA NORTHWEST — BASE FORECAST



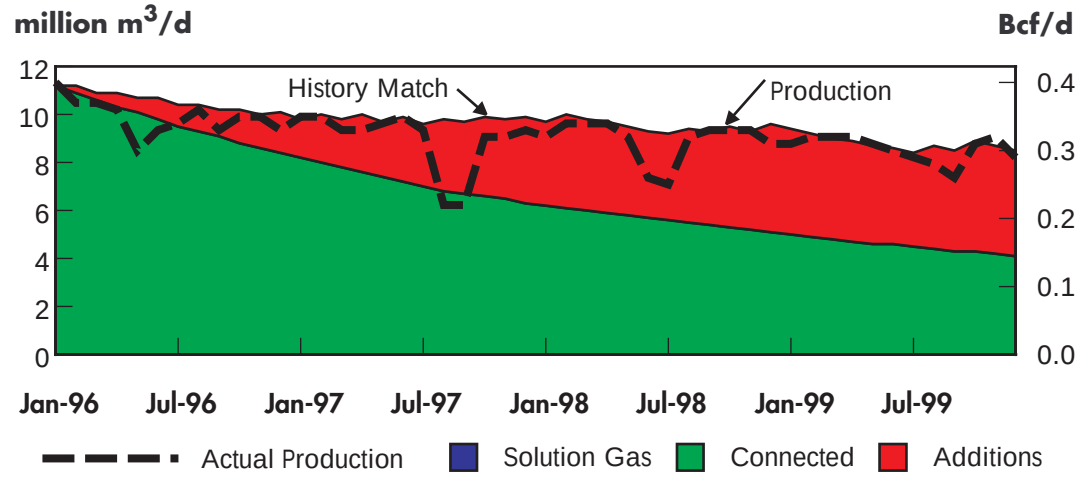
BC PLAINS — HISTORY MATCH



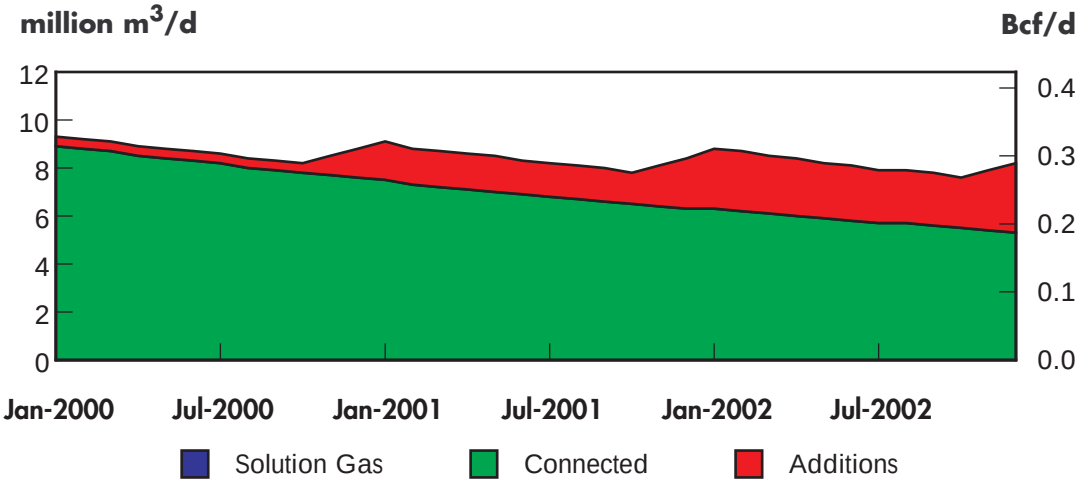
BC PLAINS — BASE FORECAST



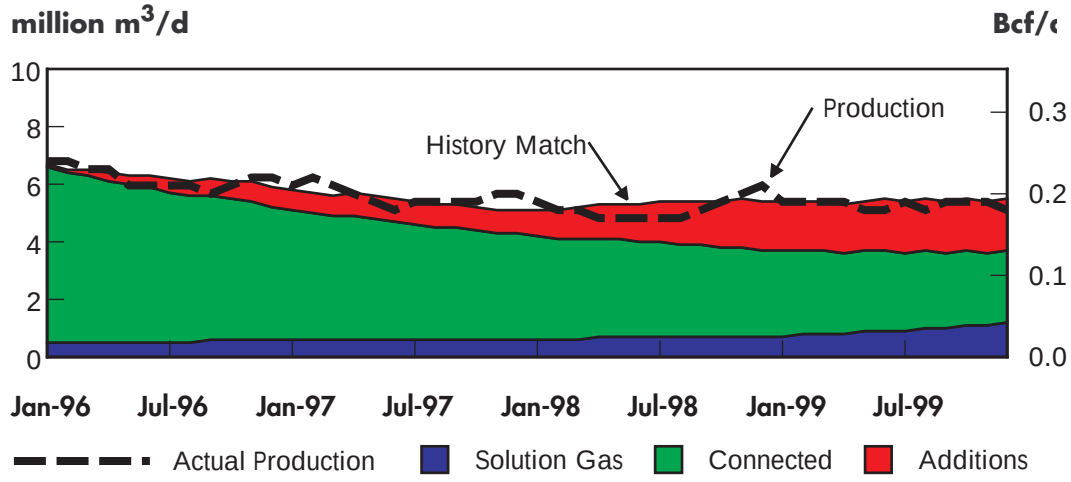
BC FOOTHILLS — HISTORY MATCH



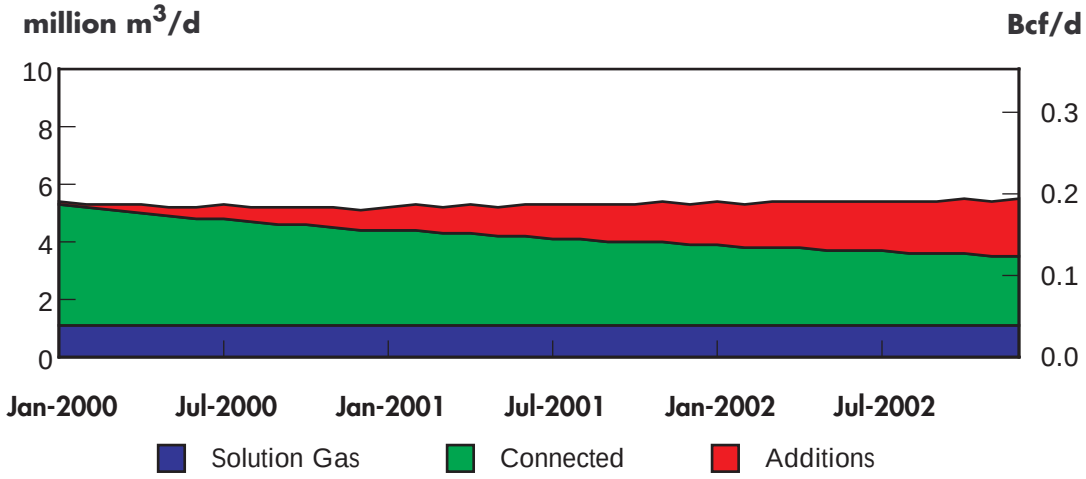
BC FOOTHILLS — BASE FORECAST



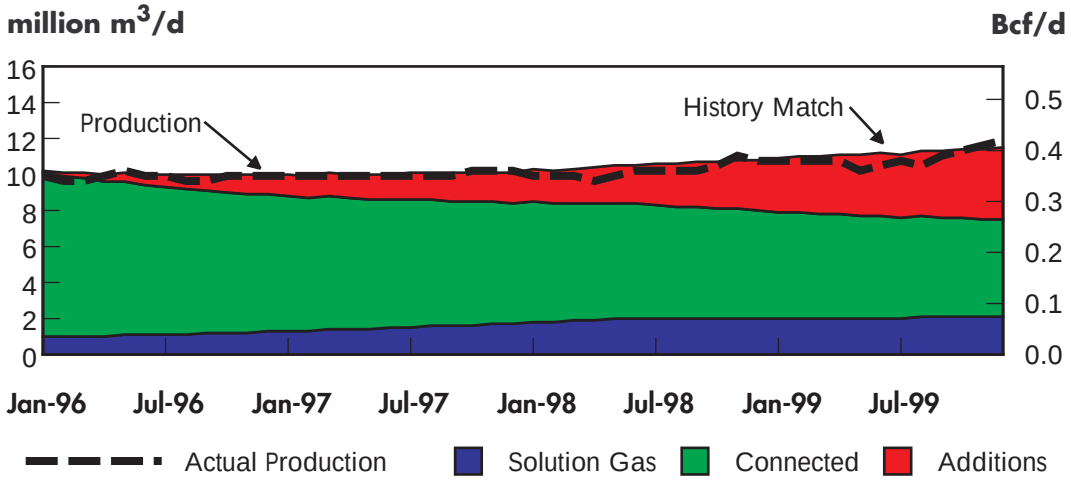
SASKATCHEWAN WEST CENTRAL — HISTORY MATCH



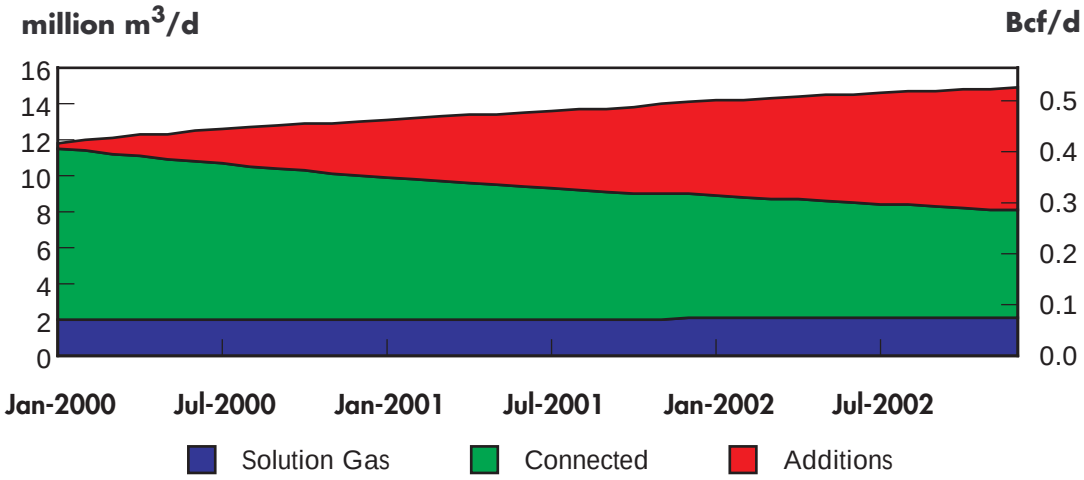
SASKATCHEWAN WEST CENTRAL — BASE FORECAST



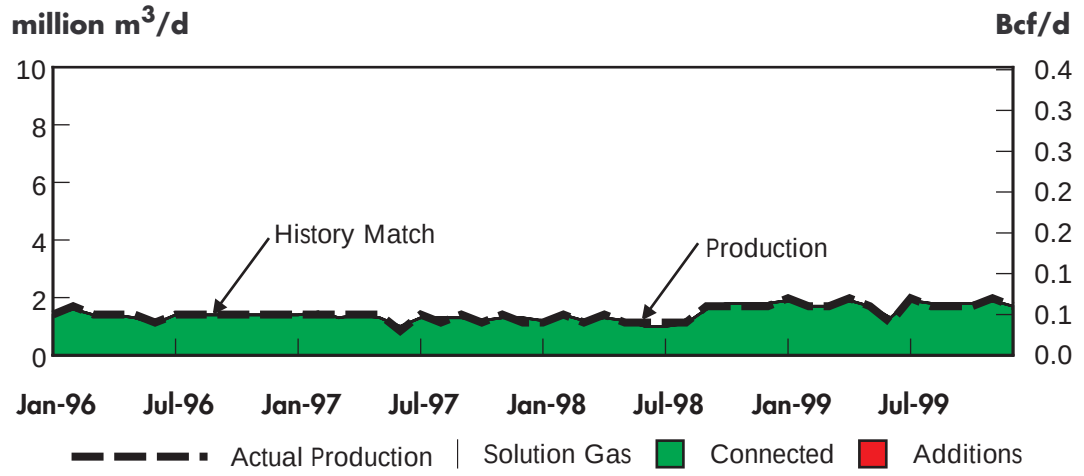
SASKATCHEWAN SOUTHWEST — HISTORY MATCH



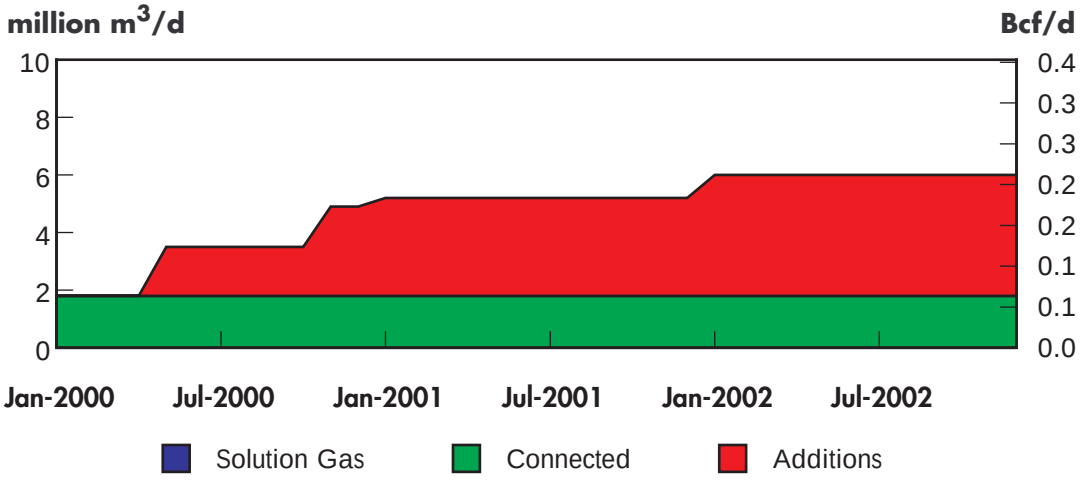
SASKATCHEWAN SOUTHWEST — BASE FORECAST



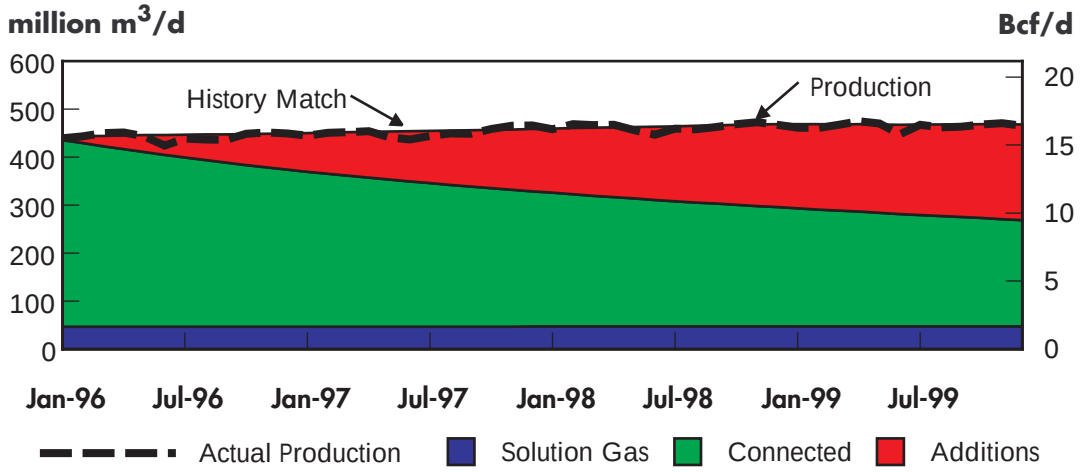
SOUTHERN TERRITORIES — HISTORY MATCH



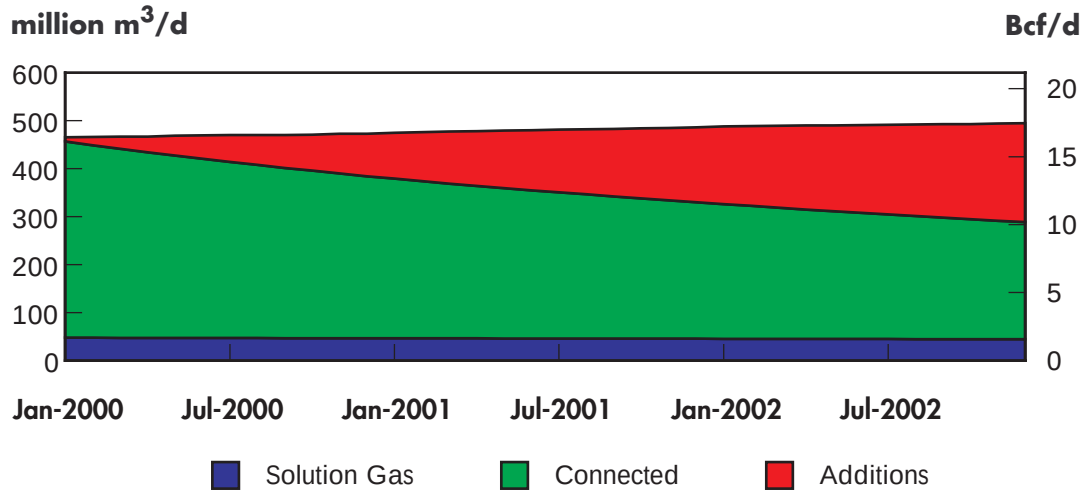
SOUTHERN TERRITORIES — BASE FORECAST



WCSB — HISTORY MATCH

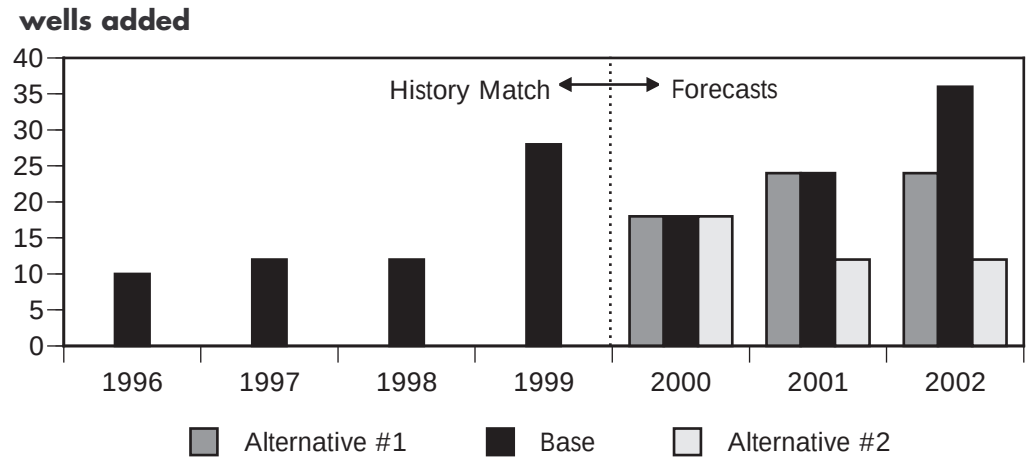


WCSB — BASE FORECAST

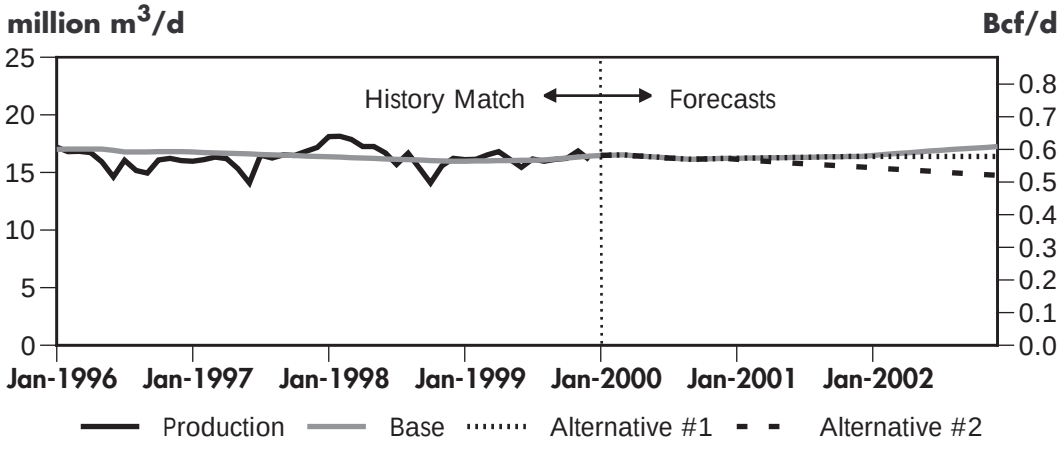


Projected Well Connection Levels and Deliverability Forecast Comparisons

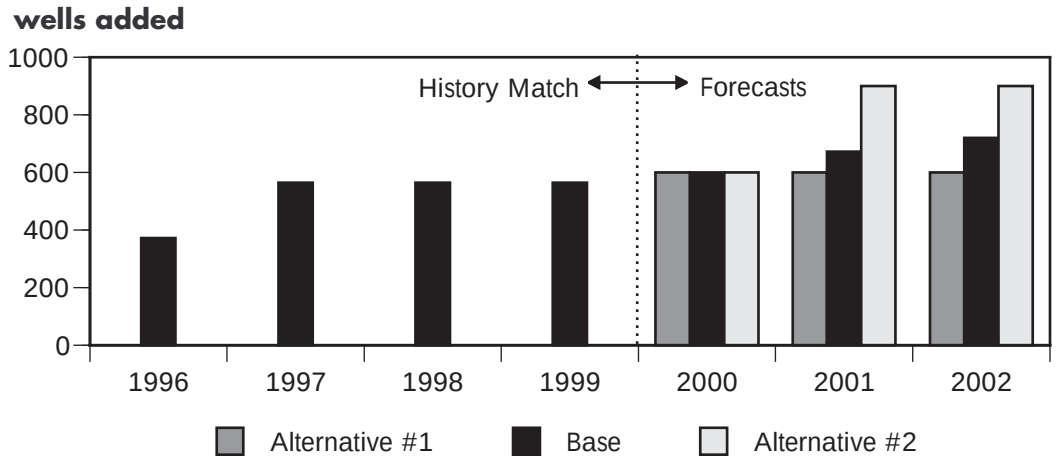
ALBERTA FOOTHILLS — GAS WELL COMPLETIONS



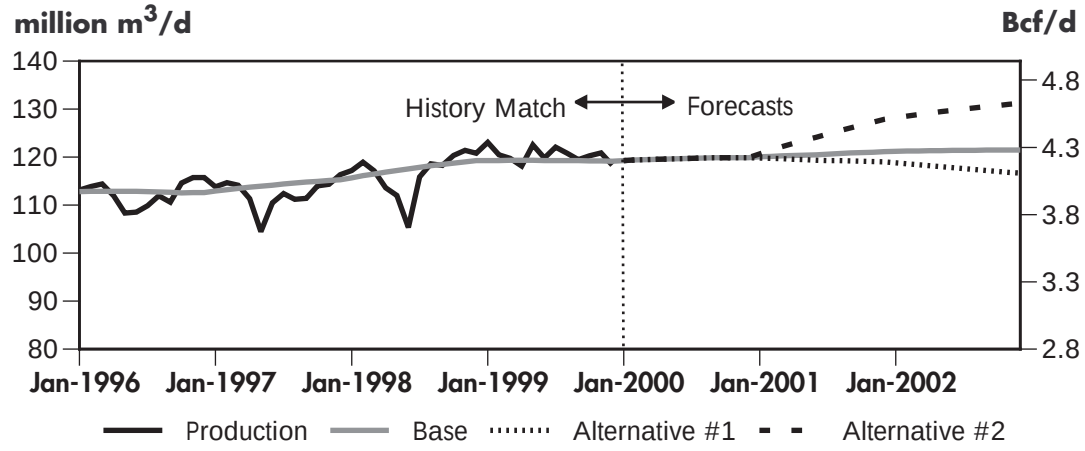
ALBERTA FOOTHILLS — DELIVERABILITY FORECASTS



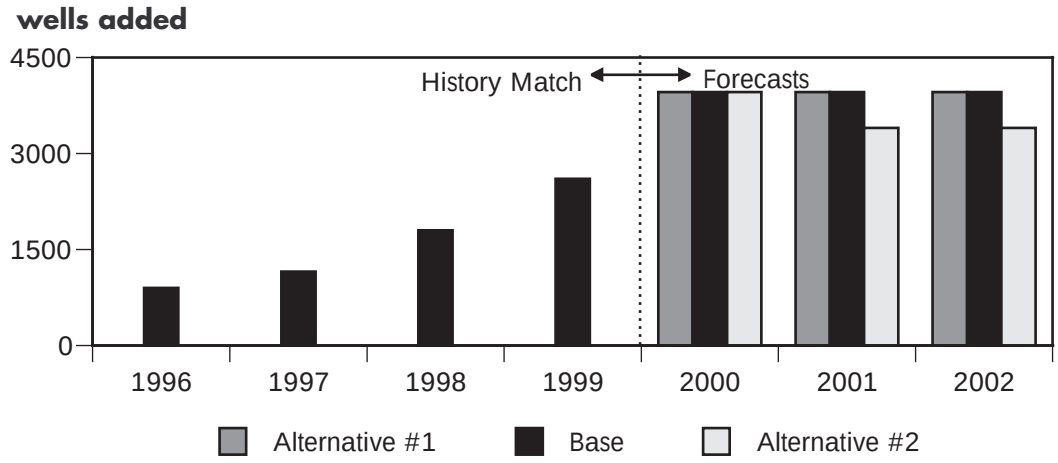
ALBERTA FOOTHILLS FRONT — GAS WELL COMPLETIONS



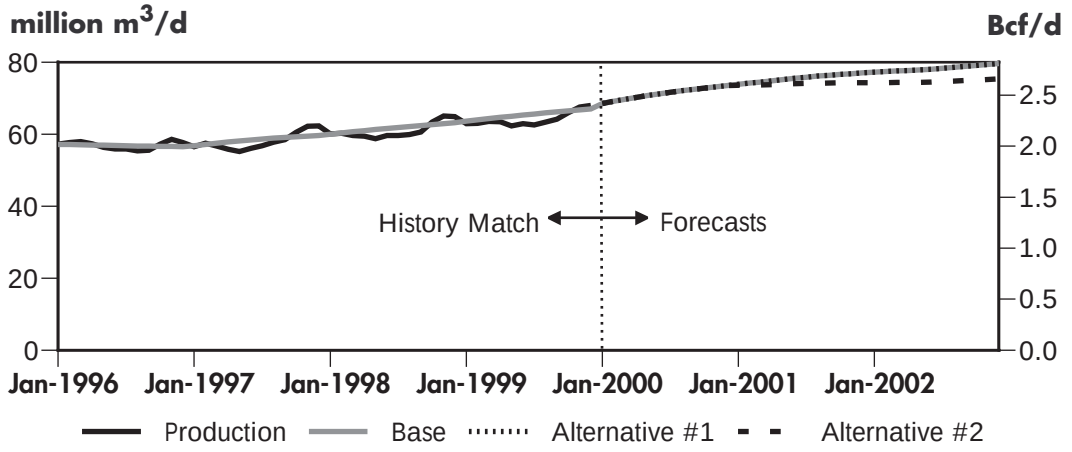
ALBERTA FOOTHILLS FRONT — DELIVERABILITY FORECASTS



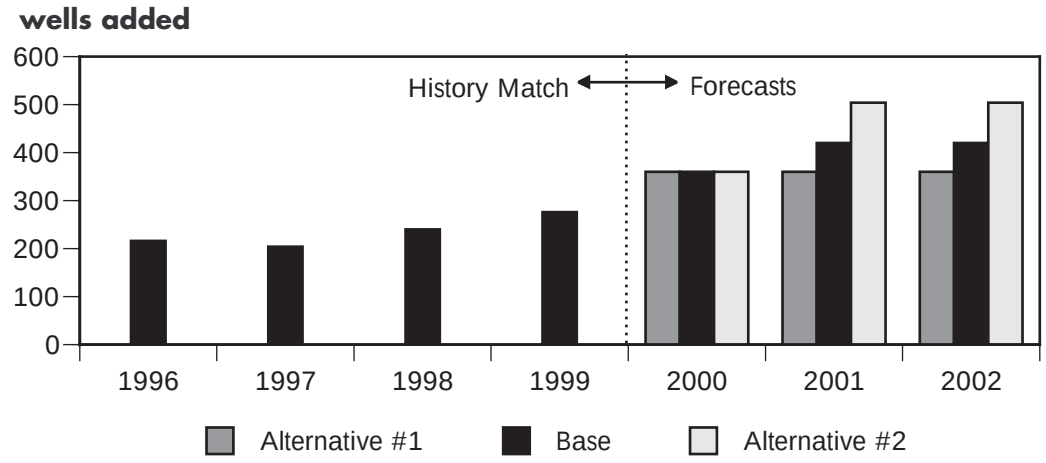
ALBERTA SOUTHEAST — GAS WELL COMPLETIONS



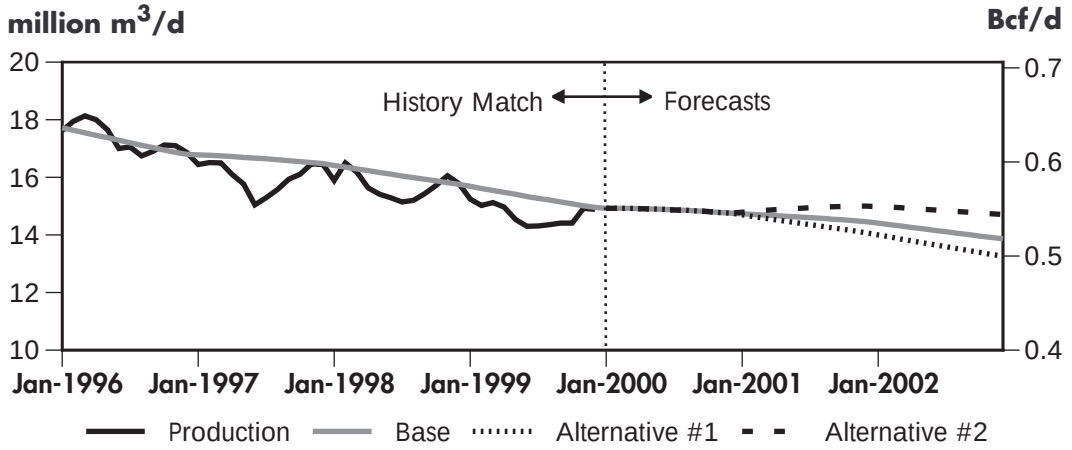
ALBERTA SOUTHEAST — DELIVERABILITY FORECASTS



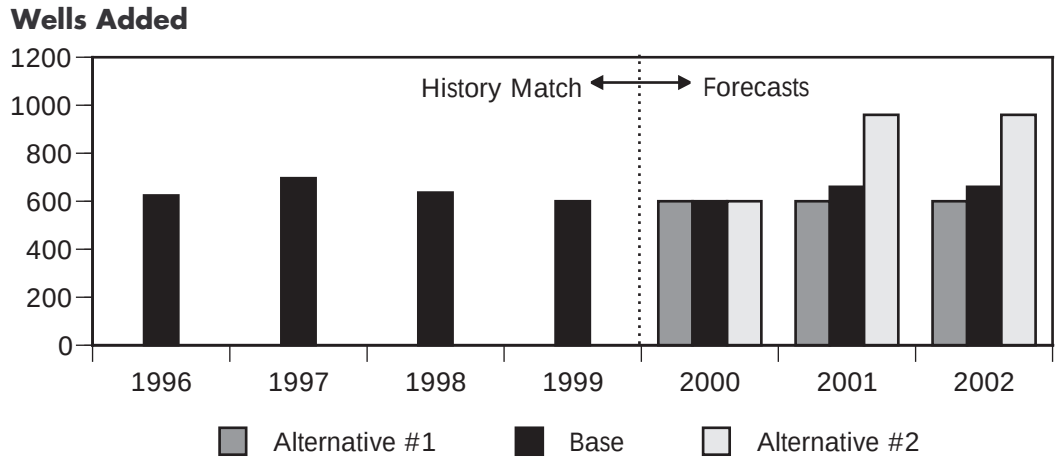
ALBERTA EAST — GAS WELL COMPLETIONS



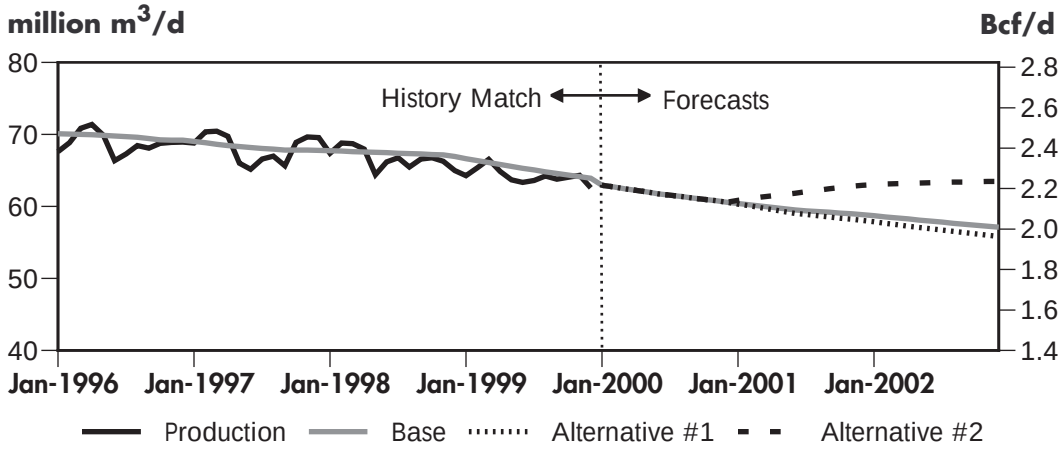
ALBERTA EAST — DELIVERABILITY FORECASTS



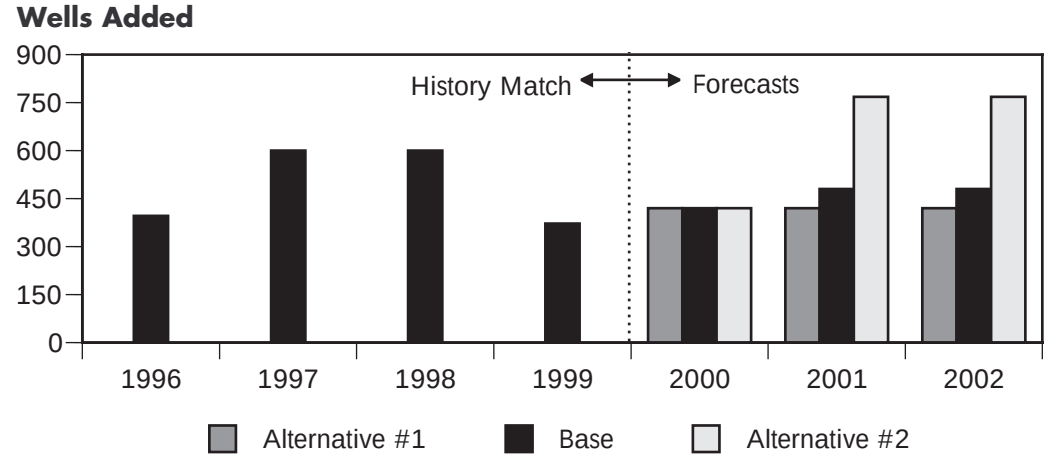
ALBERTA CENTRAL — GAS WELL COMPLETIONS



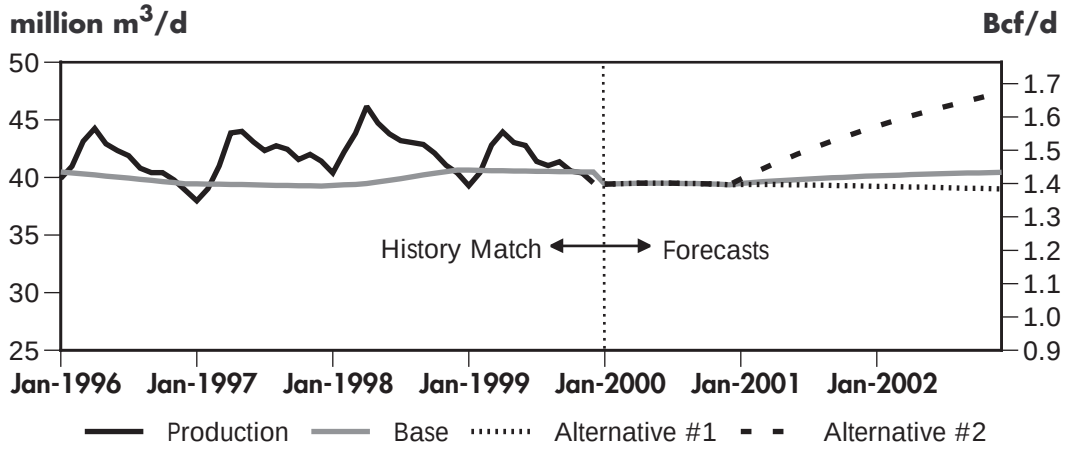
ALBERTA CENTRAL — DELIVERABILITY FORECASTS



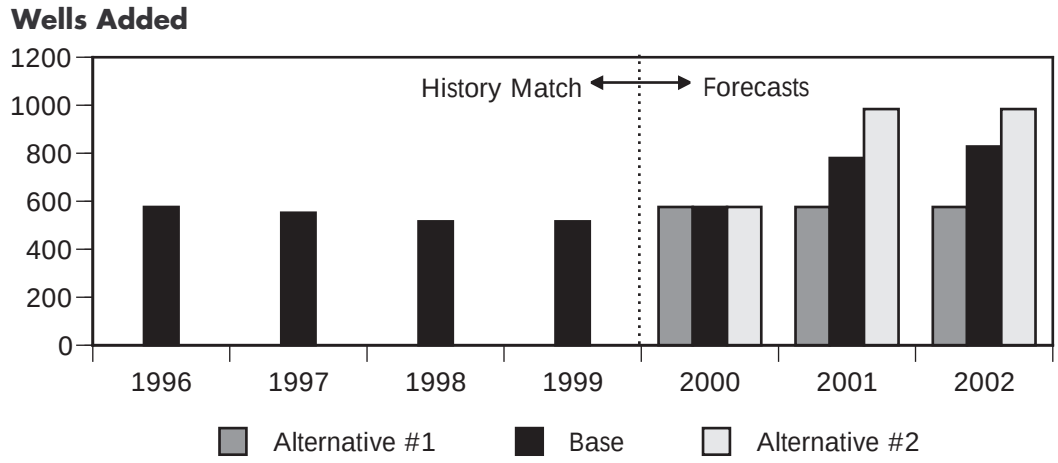
ALBERTA NORTHEAST — GAS WELL COMPLETIONS



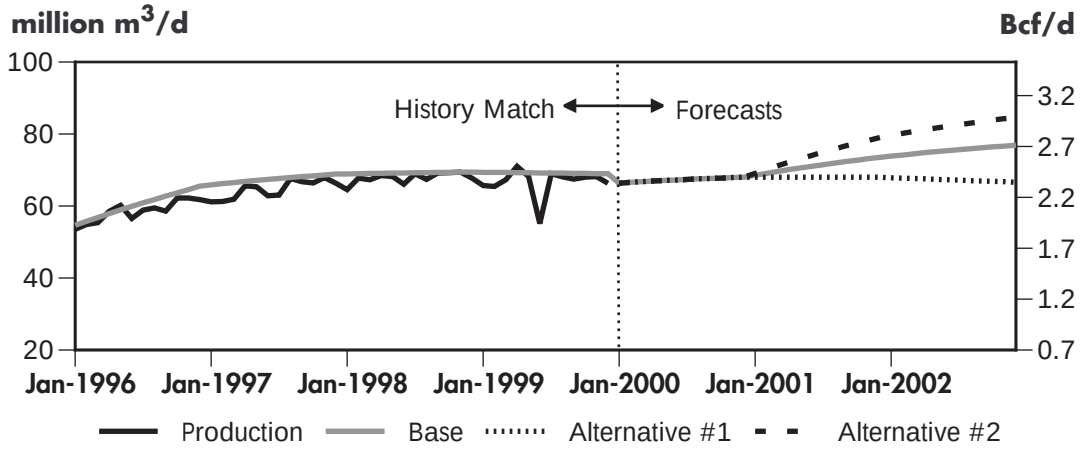
ALBERTA NORTHEAST — DELIVERABILITY FORECASTS



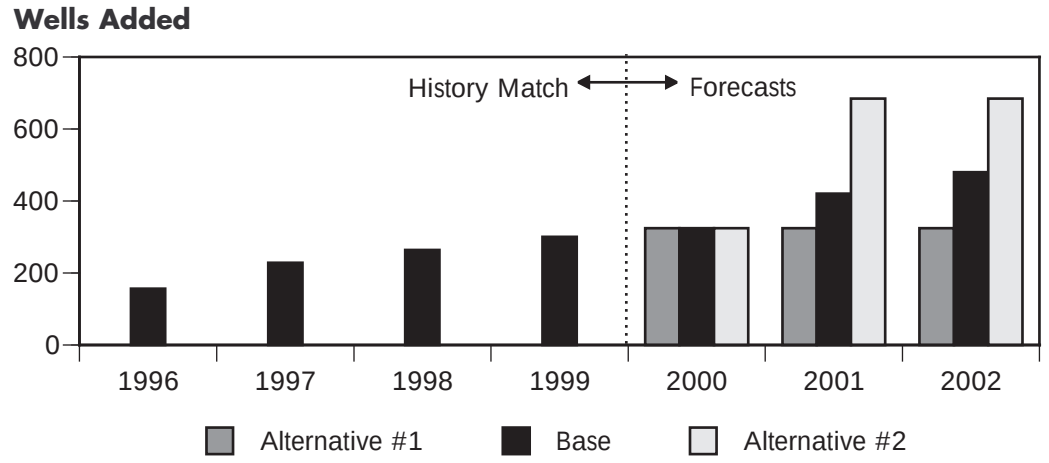
ALBERTA NORTHWEST — GAS WELL COMPLETIONS



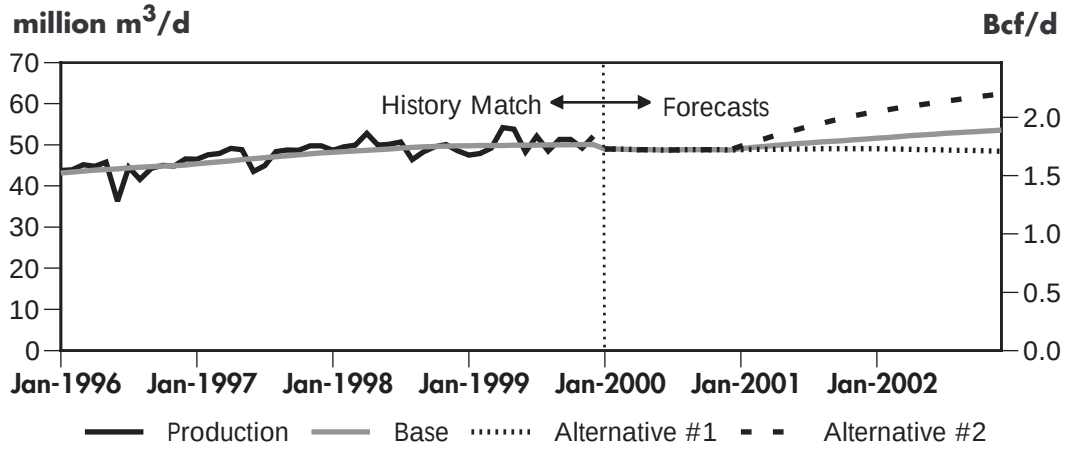
ALBERTA NORTHWEST — DELIVERABILITY FORECASTS



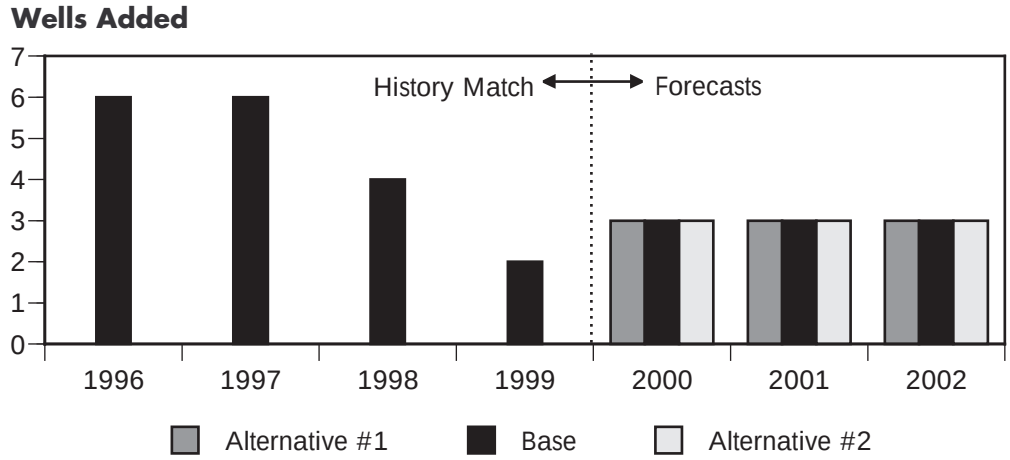
BC PLAINS — GAS WELL COMPLETIONS



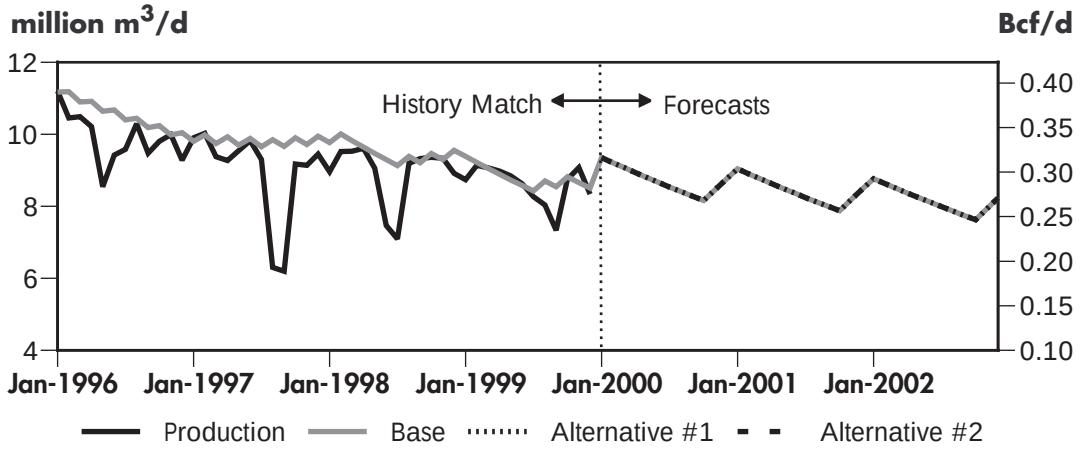
BC PLAINS — DELIVERABILITY FORECASTS



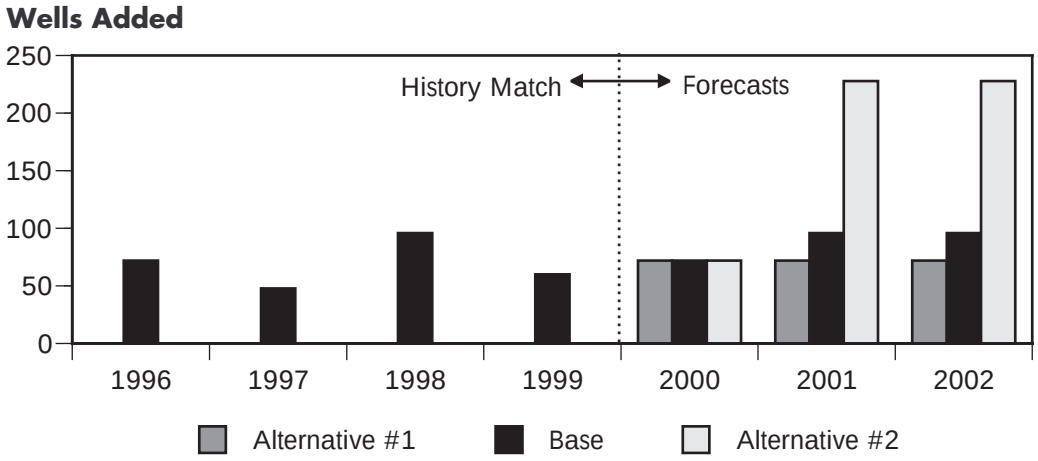
BC FOOTHILLS — GAS WELL COMPLETIONS



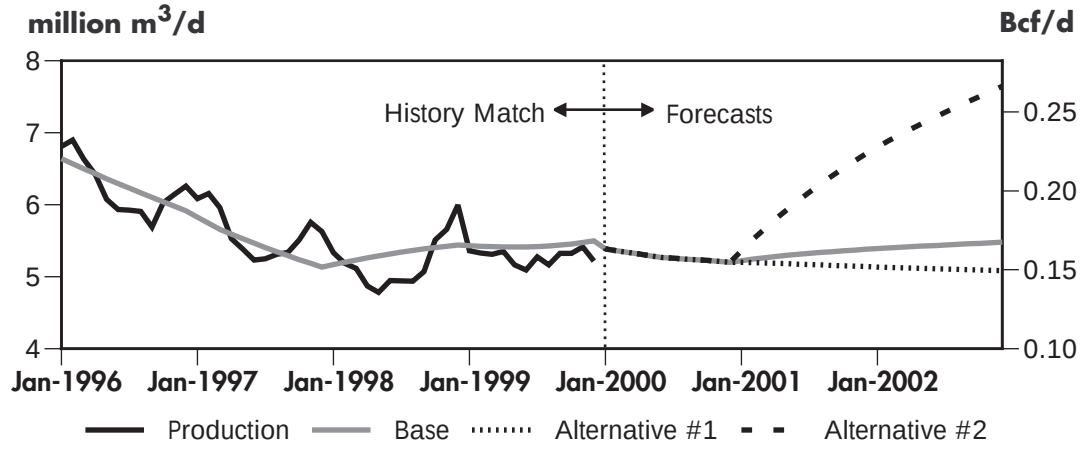
BC FOOTHILLS — DELIVERABILITY FORECASTS



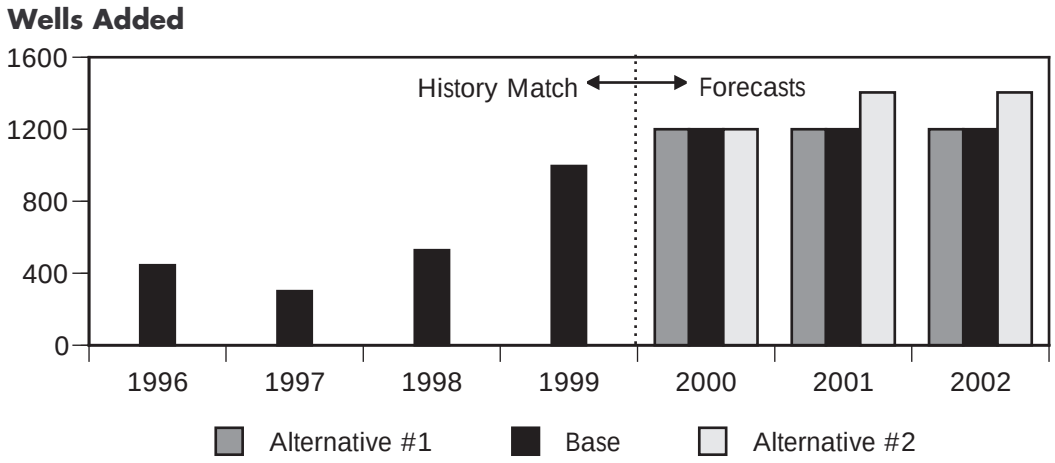
SASKATCHEWAN WEST CENTRAL — GAS WELL COMPLETIONS



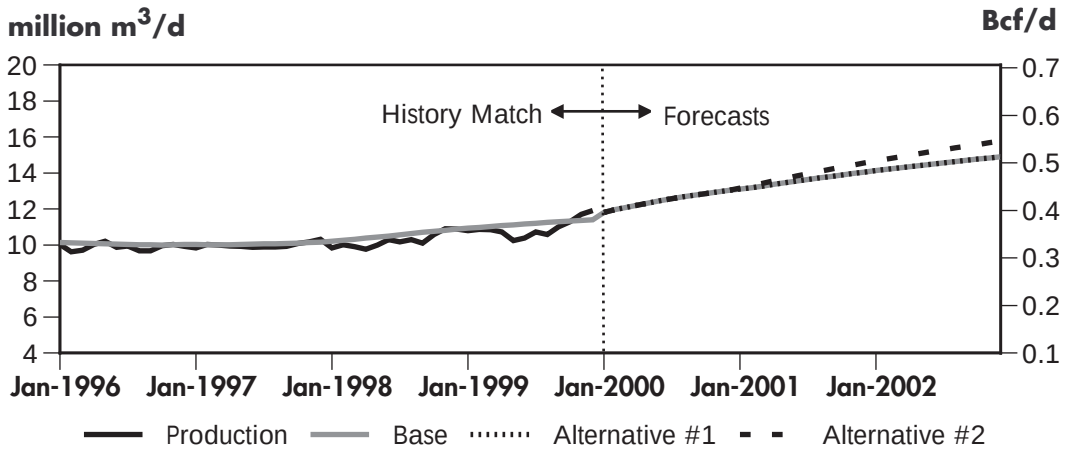
SASKATCHEWAN WEST CENTRAL — DELIVERABILITY FORECASTS



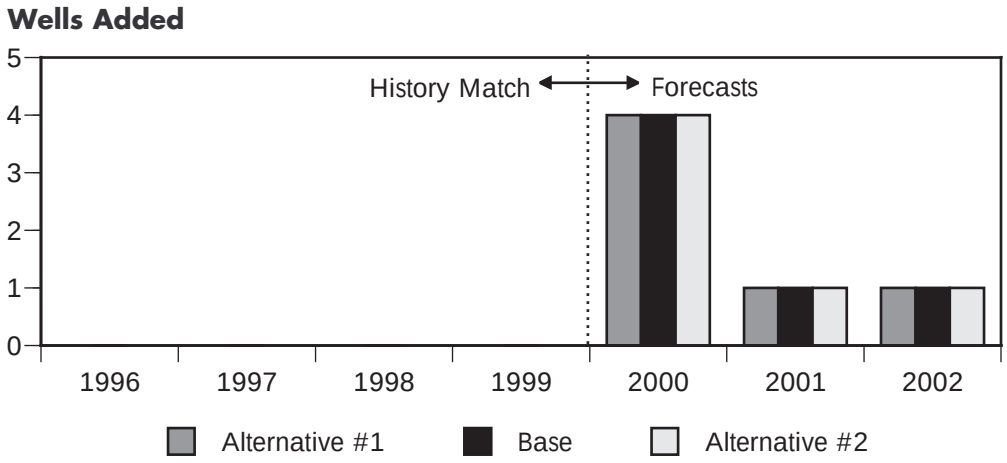
SASKATCHEWAN SOUTHWEST — GAS WELL COMPLETIONS



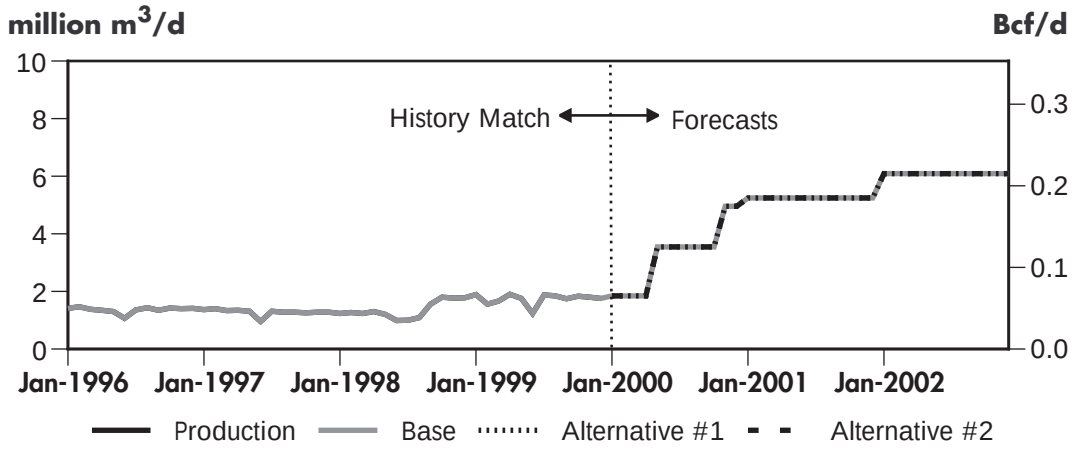
SASKATCHEWAN SOUTHWEST — DELIVERABILITY FORECASTS



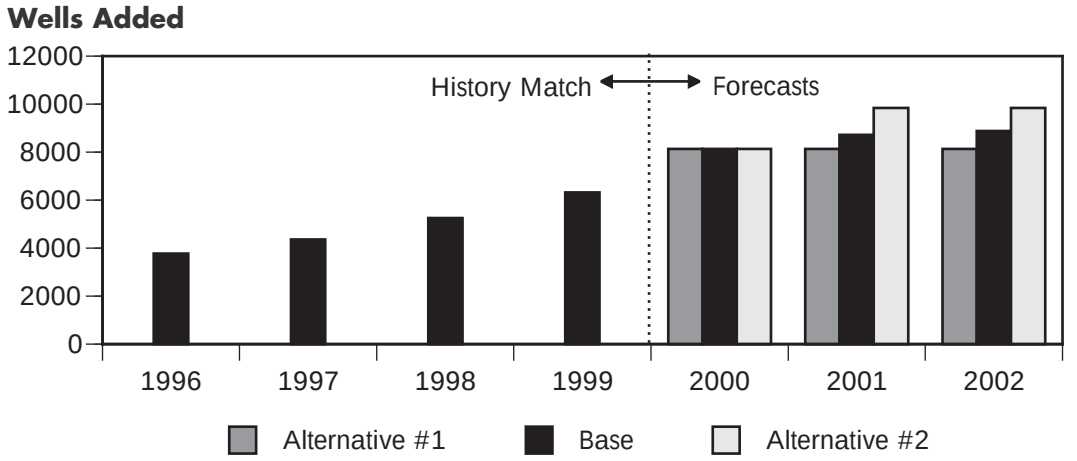
SOUTHERN TERRITORIES — GAS WELL COMPLETIONS



SOUTHERN TERRITORIES — DELIVERABILITY FORECASTS



WCSB — GAS WELL COMPLETIONS



WCSB — DELIVERABILITY FORECASTS