Joint Technical Report

National Energy Board
Office national de l'énergie

British Columbia Ministry of Energy and Mines

OGC OIL AND GAS COMMISSION
Oil and Gas Commission of British Columbia

Analysis of Horizontal Gas Well Performance in British Columbia

October 2000

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Abbreviations

10^3	thousand
10^6	million
10^3m^3	thousand cubic metres
10^6m^3	million cubic metres
abd.	abandoned
BCMEM	British Columbia Ministry of Energy and Mines
OGC	Oil & Gas Commission of British Columbia
cum	cumulative
m^3	cubic metres
NEB, the Board	National Energy Board
N	North
PEEP	Petroleum Economic Evaluation Program
susp	suspended
WGR	water-gas ratio
yr	year

FOREWORD

The National Energy Board (the Board or NEB) continually monitors the overall energy situation in Canada by identifying long and short term developments in supply and demand. The Board publishes reports on long term developments in its Supply and Demand Reports, the short term outlook as Energy Market Assessments, and occasionally publishes reports of a more technical nature.

This report, entitled *Analysis of Horizontal Gas Well Performance in British Columbia* , provides an overview of the use of horizontal well technology for gas production in Northeast British Columbia from 1988 to 1998. It is intended for use by a technical audience and seeks to outline, as concisely as possible, the current state of horizontal technology development, the current status of technology application, and the probable impacts of the technology.

This report was prepared by the National Energy Board, the Oil and Gas Commission of British Columbia (OGC) and the British Columbia Ministry of Energy and Mines (BCMEM). The information contained herein should not be construed as a policy position of the NEB, OGC, BCMEM or any other organization.

These agencies welcome any comments on the design or use of the selected methodology, or on the results of this report. Comments should be directed to the Secretary, National Energy Board, 444 - Seventh Avenue SW, Calgary, Alberta, Canada T2P 0X8.

EXECUTIVE SUMMARY

This report reviews the current use of horizontal wells for production of natural gas in British Columbia. The technical objective of horizontal drilling is to provide economic benefits by exposing significantly more reservoir rock to the well-bore surface than can be achieved via drilling a conventional vertical well.

This report suggests that horizontal gas well projects must be carefully analyzed to optimize drilling and completion practices because their costs are higher and the reservoir behaviour is more complex. The report also concludes that the "better" production performances and financial benefits are the result of a number of factors.

First, operators often are able to develop a reservoir with a sufficiently smaller number of wells since each horizontal well will drain a larger rock volume about its bore than a vertical well. As a result, proved reserves per well are higher than they would be for a vertical well. For example, the Midwinter Jean Marie C pool is developed with only 16 horizontal wells. It is estimated that 57 vertical wells would be required to reach the same stage of development.

Second, a horizontal well may produce at rates several times greater than a vertical well due to the increased wellbore surface area that is exposed within the producing interval. A faster producing rate translates to a higher recovery. In the Midwinter Jean Marie A pool, under equal pressure conditions, horizontal completions produce at initial rates three to four times higher than vertical completions. The seven horizontal wells have produced about 83 per cent of the total raw gas production as oppose to the 13 per cent recovered by the six vertical wells. It is also expected that a successful horizontal well will lower the supply costs by at least 10 per cent.

Third, use of a horizontal well may preclude or significantly delay the onset of production problems that are associated with low production rates, low recovery efficiencies, and/or premature well abandonment.

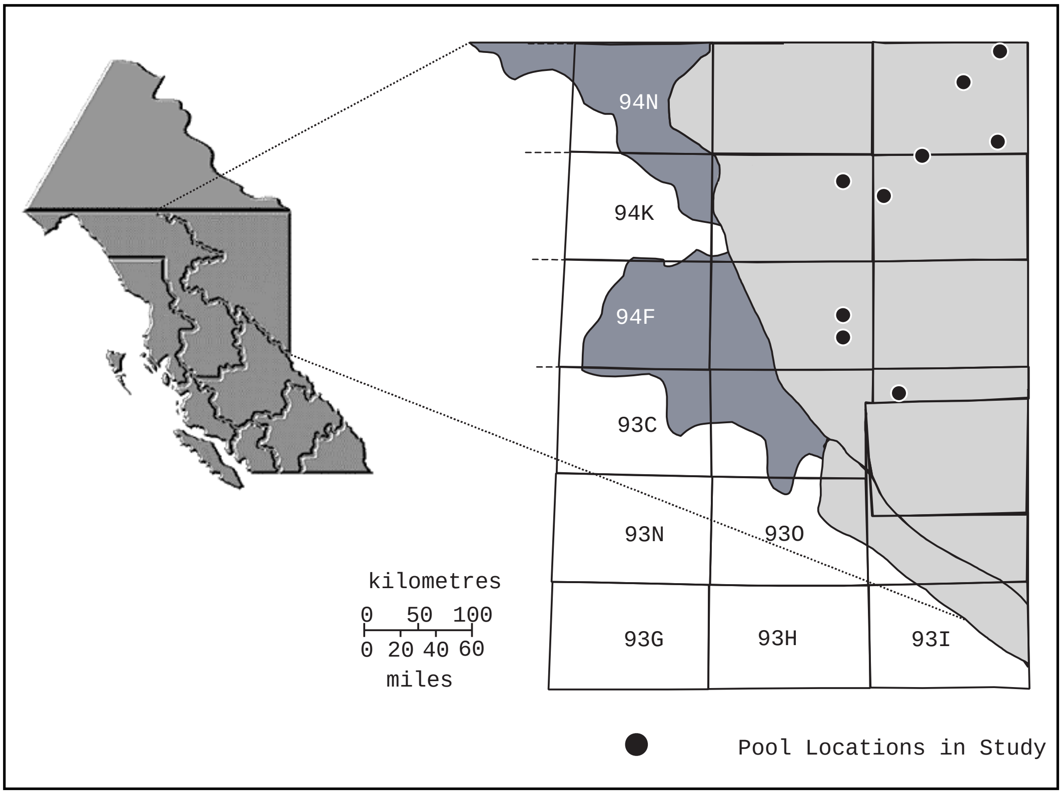
INTRODUCTION

Horizontal wells are not new. The use of horizontal drilling technology in petroleum exploration, development, and production operations has grown rapidly over the past decade. To date, most horizontal wells have targeted crude oil reservoirs. There is no physical reason why they should not also be utilized for natural gas. The success of horizontal drilling, particularly in Saskatchewan, has encouraged testing in many geographical regions and geological situations. Horizontal bore-hole lengths have grown rapidly and horizontal displacements now have been extended to over 2 440 metres (8,000 feet). The newer techniques of well re-entry, short radius horizontal drilling, under-balanced coiled tubing drilling, advanced horizontal completions and multilateral wells are all experiencing huge increases in application. These new techniques lead the way to exploiting reservoirs where gas/oil production can be improved using horizontal related technology. Low cost application and three to ten times improvement in production rates and higher ultimate hydrocarbon recovery make the use of this technology attractive. The advent of smaller diameter directional drilling tools, real-time monitoring systems and coiled-tubing drilling has opened the door to slim hole re-entry horizontal wells.

The application of horizontal drilling technology to the discovery and productive development of gas reserves in B.C. has become a frequent event in the five year period from 1993 to 1998. The total number of gas-related horizontal wells has increased from seven to 268 in the same period of time. Due to its higher cost, horizontal drilling is currently restricted to situations where reservoir characteristics indicate that vertical wells would not be as financially successful.

FIGURE 1

Northeast British Columbia



This paper focuses primarily on the application of horizontal drilling for the production of natural gas in British Columbia. At year-end 1998, 147 of the 268 horizontal gas wells drilled were producing. Total cumulative raw gas production was 10 225 $10^6 m^3$ (Appendix 3). Twenty-eight operators have used this technology in B.C. with Petro-Canada and Ranger Oil making the most use (Appendix 1). The most frequent targets for gas have been the Upper Devonian Jean Marie carbonate complex (81 wells), the Triassic Baldonnel carbonates (25 wells) and the Middle Devonian carbonate reefs including the Slave Point (15 wells) and Pine Point Formations (13 wells)(Appendix 2).

FIGURE 2

Performance of B.C. Horizontal Gas Wells

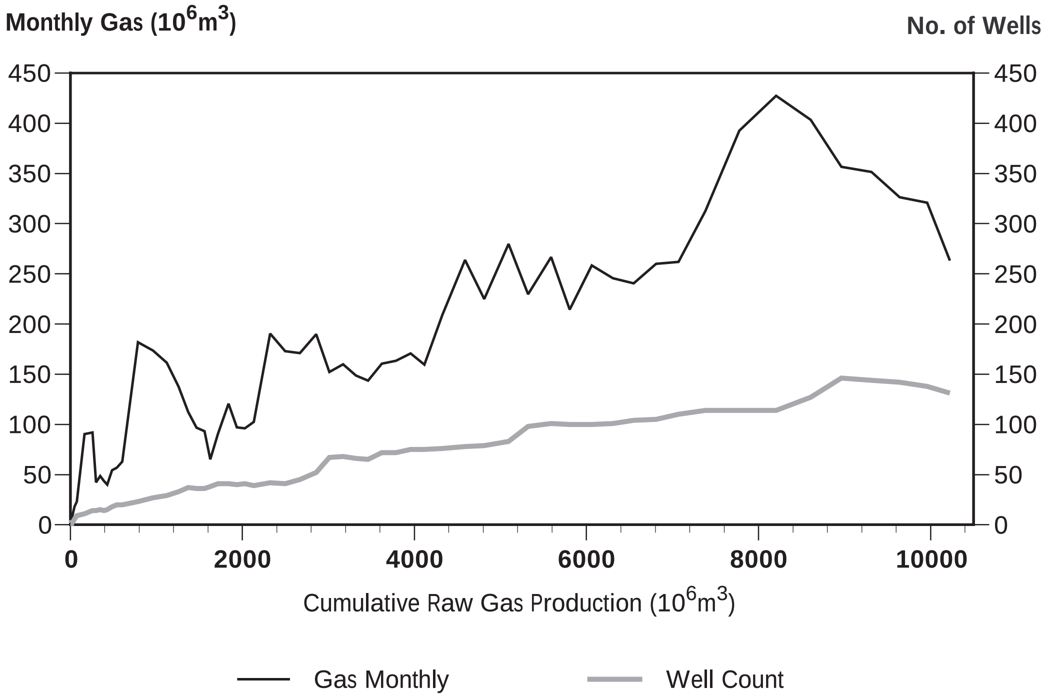
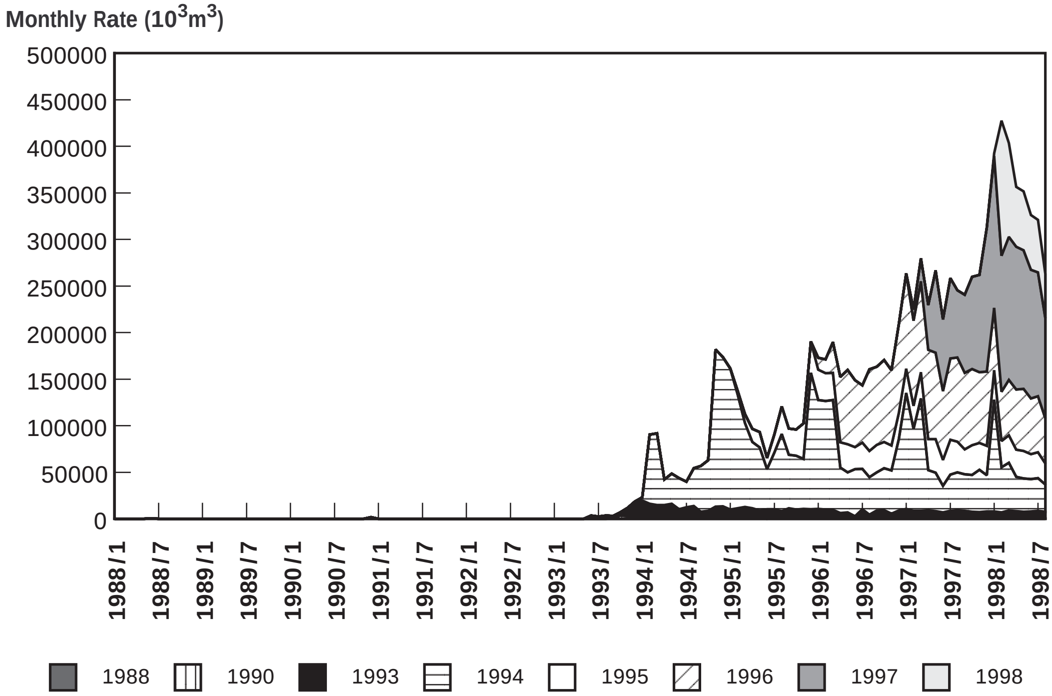


FIGURE 3

Gas Production by On-Production Year



METHODOLOGY

Statistical and graphical analyses of production data can be invaluable for evaluations of well and pool performance. The methodology used for this study is summarized in Table 1.

Table 2 summarizes the production indicators that were reviewed. It was determined that the best indicator of reservoir quality is the "Monthly Gas Rate", because gas production is reported to the British Columbia Ministry of Energy and Mines (BCMEM) on a monthly basis and wells are not always on production. The choice of which rate (an average monthly production for each pool or production of a well which represented the median of the pool sample) to use for each pool evaluated was a more difficult decision. The answer varies depending upon the type of reservoir and what data is available. In most cases, the results are similar within a reasonable range.

A large amount of production data was reviewed for quality assurance. Although a total of 268 horizontal wells were drilled, only 86 of the 147 producing wells provided enough information to be analyzed in this study. These 86 wells are found in only 10 pools. These 10 pools were then selected for detailed analysis. Average production profiles for both horizontal and vertical wells were developed for each pool. Vertical wells that had a first production date similar to that of the horizontal wells were selected in order to compare well production performance at the equivalent state of reservoir depletion.

The monthly production data for each well was retrieved and normalized. This data was analyzed to establish average or typical rates in the selected pool. A decline analysis was then used on the monthly rate-time plot to estimate monthly gas production and cumulative gas production per well over a three to five year period. The production data and decline profiles were then used to calculate monthly rates in order to establish average monthly production profiles for both horizontal and vertical wells. (Appendices 4, 5, 6).

TABLE 1

Production Performance Methodology

1.	Retrieve production data for horizontal and vertical wells
2.	Sum gas production and production hours by months to calculate average rates
3.	Exponential decline analysis of cum-rate plot to estimate recoverable gas per well and calculate decline rate
4.	Use production data and decline rates to produce a production profile for both horizontal and vertical wells
5.	Use information from step 4 to produce probabilistic production and overall recovery profiles for both horizontal and vertical wells

TABLE 2

Production Indicators Calculated For Producing Horizontal Gas Wells

1.	Maximum gas production rate
2.	Maximum water production
3.	Monthly gas rate during best 6-month production period
4.	Monthly water rate during best 6-month production period
5.	Time to maximum gas rate and time to maximum water rate
6.	Time to best 6-month gas production
7.	Gas/water ratio

RESULTS AND DISCUSSION

Gas production from horizontal wells began in 1988; however, most of the production schemes were implemented after 1993. At year-end 1998, there were 179 gas wells, 52 abandoned or suspended wells and 33 potential gas wells. Operators have generally focused on low risk re-entry horizontal and moderate risk development wells in existing pools where hydrocarbons are known to exist. The most frequent targets have been the Upper Devonian Jean Marie carbonate complex, Triassic Baldonnel carbonates and the Middle Devonian carbonate reefs. There were only five high risk exploration wells drilled, two of which were successful. The overall success rate for low and moderate risk development wells was 65 per cent as compared to 40 per cent for high risk exploration wells.

It should be noted that 11 of the 147 producing horizontal gas wells (Appendix 7) were drilled as vertical wells prior to 1986 and were then re-completed as re-entry horizontal gas wells in the 1990s. Re-entry, once thought of as a last resort, has become an option for extending field life and improving hydrocarbon production. The cumulative gas production from these 11 wells was 2 290 $10^6 m^3$, or 22.4 per cent of the total horizontal gas production to date. The 147 producing wells currently account for about 92 per cent of the cumulative horizontal gas production in B.C. (Appendix 8).

By far, the most intensive application of horizontal drilling has been in the Upper Devonian Jean Marie Formation. At year-end 1998, 30 per cent of all horizontal gas wells (or 81 wells) had been drilled into the Jean Marie. The Jean Marie Formation is a massive, gas-bearing carbonate shelf, which in many locations, is extensively fractured. Most of the productive permeability in the formation is fracture permeability, rather than matrix permeability. As a consequence, horizontal wells drilled to intersect several vertical fractures at right angles have typically demonstrated much larger initial production rates than were provided by previously drilled vertical wells. Jean Marie horizontal wells, with the exception of the six horizontal wells drilled in the Helmet North Field, are more productive than the conventional vertical wells and have been responsible for the recent increase of gas production from this formation. A number of the wells tested at flow rates of over 3 000 $10^3 m^3$ per month. The productivity ratios (quantity obtained from the horizontal well relative to the offset vertical well) are in the range of 1.9 to 3.8 after one year of production.

Horizontal gas wells in B.C. generally exhibit an exponential decline. On average, they show two to three times improvement in initial production rates and higher ultimate hydrocarbon recovery than did vertical wells. Also, the production rates declined more rapidly than a conventional vertical well in the same formation. The high decline rate demonstrates that horizontal and multilateral drilling technology offers improved drainage in typical reservoirs and penetrates more of the discrete compartments in complex reservoirs while also helping to reduce water coning problems. In simple terms, with careful planning and implementation, low and moderate risk development horizontal wells allow operators to produce more efficiently than with vertical wells alone in existing pools. Only 20 (9 abandoned and 11 suspended) of the 52 horizontal wells currently classified as abandoned and suspended ever produced. The production data suggests that most of these wells failed because either the initial rates were too low or the monthly rates declined so rapidly that the operation became uneconomic. A small number of the wells failed due to a combination of low flow rates and high water-gas ratios (WGRs), over 500 $m^3/10^6 m^3$.

RESULTS FOR ANALYZED POOLS

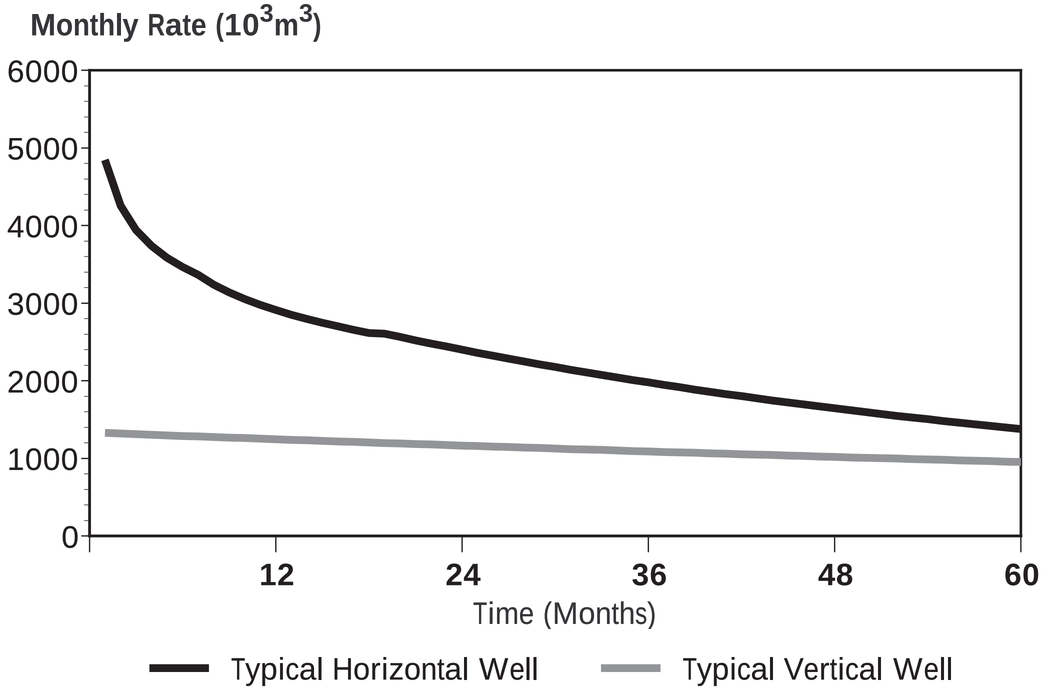
Bubbles North Field - Baldonnel/Upper Charlie Lake A Pool

The Baldonnel and Charlie Lake Formations in the Bubbles North area thicken westward up to 21 metres with average porosities up to eight per cent. The Baldonnel consists mainly of peloidal and bioclastic dolostones, with rare limestones and breccias. The Charlie Lake Formation is composed of a succession of intercalated nearshore sandstone, siltstone, and dolomite deposits.

The Bubbles North Baldonnel/Upper Charlie Lake A pool consists of four active horizontal and ten vertical gas wells. The production performance charts for both horizontal wells and the six vertical wells that were drilled in the same time period suggest that the initial monthly gas rate is about 4 800 10^3m^3/month for a typical horizontal well and 1 300 10^3m^3/month for a typical vertical well (Figure 4). Vertical wells do not perform well once the production rate drops below 1 000 10^3m^3/month due to the high WGRs associated with production. For a typical horizontal well, the cumulative gas production is expected to be in the 110-420 10^6m^3 range, compared to 60-210 10^6m^3 forecasted for a typical vertical well. It is estimated that under the current production scheme, about 45 per cent of the total pool production will come from these horizontal wells.

FIGURE 4

Bubbles North Baldonnel/Upper Charlie Lake A



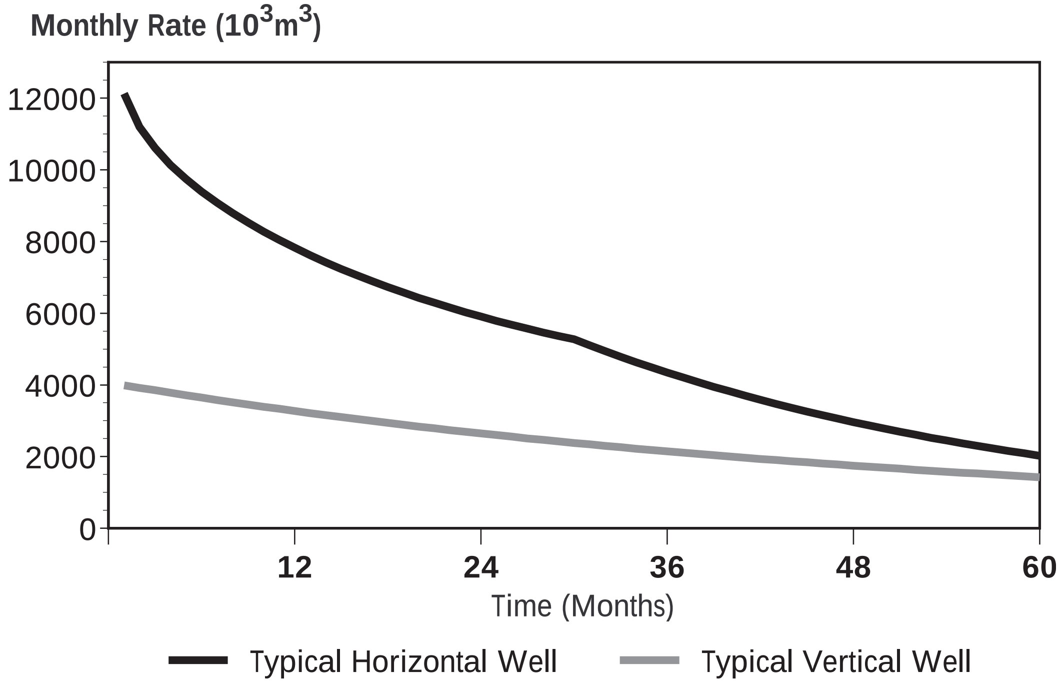
Clarke Lake Field - Slave Point A Pool

Gas production from vertical wells in this pool began in 1961. The production history shows that large volumes of water have always been associated with gas production. Production from horizontal wells began in 1994. Currently, there is a total of 67 wells drilled, 37 of which are producing (8 horizontal and 29 vertical). Nine of the 11 horizontal wells drilled in this pool are new development wells and were placed on production after 1993. During the same period of time, there were ten vertical development wells that were put on production. The production data shows that these horizontal wells have produced 75 per cent (or 1 097 10^6m^3) of the 1 477 10^6m^3 of raw gas produced from this pool since 1994 while WGRs remained under 200 $m^3/10^6m^3$. The WGRs for the producing vertical wells are in the 1 000 to 2 000 $m^3/10^6m^3$ range.

The success of horizontal wells in this pool can be attributed to the fact that these wells offer improved drainage and penetrate more of the discrete compartments in this complex reservoir. They also help to reduce water production problems. The analysis indicates that the initial monthly rate for a typical horizontal well is approximately 12 000 10^3m^3/month or about three times that of a typical vertical well in this pool (Figure 5). The cumulative gas production is expected to be in the 250-960 10^6m^3 range compared to the 50-360 10^6m^3 range predicted for a typical vertical well.

FIGURE 5

Clarke Lake Slave Point A



Fireweed Field - Baldonnel E Pool

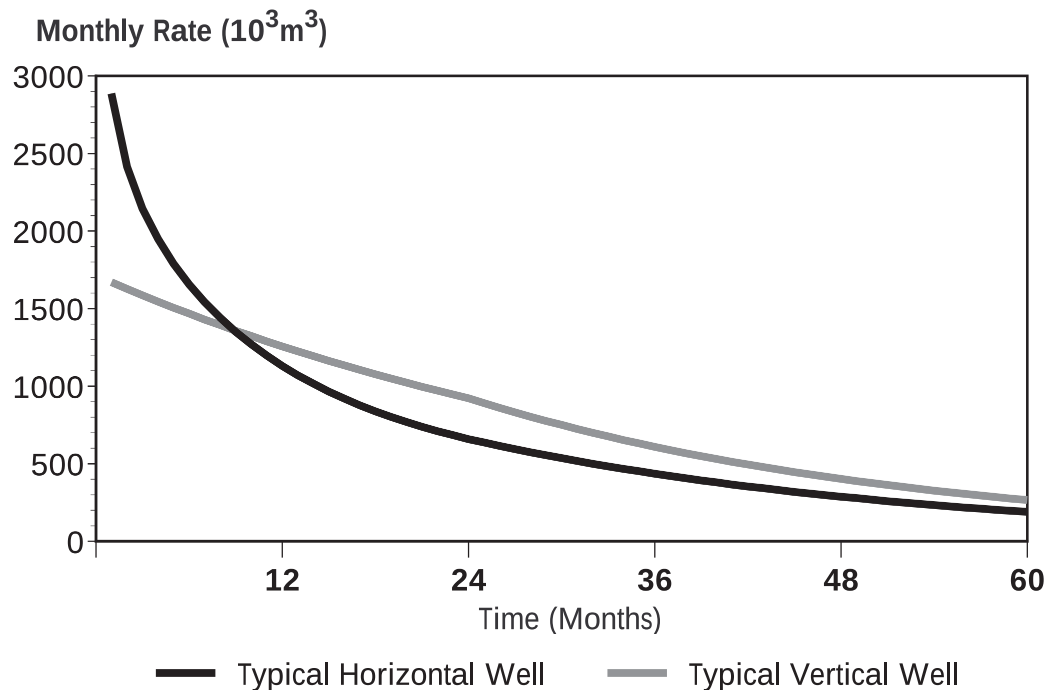
Gas production from this pool began in 1986 and a total of 46.5 10^6m^3 of raw gas was produced from the Fireweed b-006-A/094-A-13/0 well before the first horizontal gas well (re-completed in an abandoned dry hole) was put on production in November, 1993. There are now six wells; four horizontal and two vertical wells in this pool. A total of 153 10^6m^3 of raw gas, or 52 per cent of the 292 10^6m^3 cumulative production has been produced from the horizontal wells. Since 1994, all development wells, both vertical and horizontal, have been drilled along a northeast trend where drainage is believed to be better.

Note that the producing vertical well, Fireweed c-35-A/094-A-13, has produced more raw gas than any of the four horizontal wells. The difference between this well and the horizontal wells can be attributed to the number of pay zones, the thickness of each pay zone and good matrix permeability in all directions. Production from the horizontal well, Fireweed d-005-A/094-A-1, lasted for about a year, while production from a nearby offsetting vertical well, Fireweed b-006-A/094-A-13, which has similar geology, lasted well over eight years and produced more gas.

The analysis suggests that the initial monthly rate for a typical horizontal well is about 2 900 10^3m^3, about 70 per cent higher than for a typical vertical well. The cumulative production after one year is still about 20 per cent higher than that of a typical vertical well but is 10 per cent lower after three years of production (Figure 6). It also suggests that due to the high water saturations (over 30 per cent) in this pool, gas production is affected by the well location and production practices. This is one case where the performance of horizontal wells is similar to a typical vertical well. However, in this pool, vertical wells have penetrated more than one reservoir zone, while horizontal wells have only penetrated one zone. The overall cumulative gas production for a typical horizontal well is expected to be in the 40-150 10^6m^3 range compared to the 30-110 10^6m^3 range predicted for a typical vertical well.

FIGURE 6

Fireweed Baldonnel E



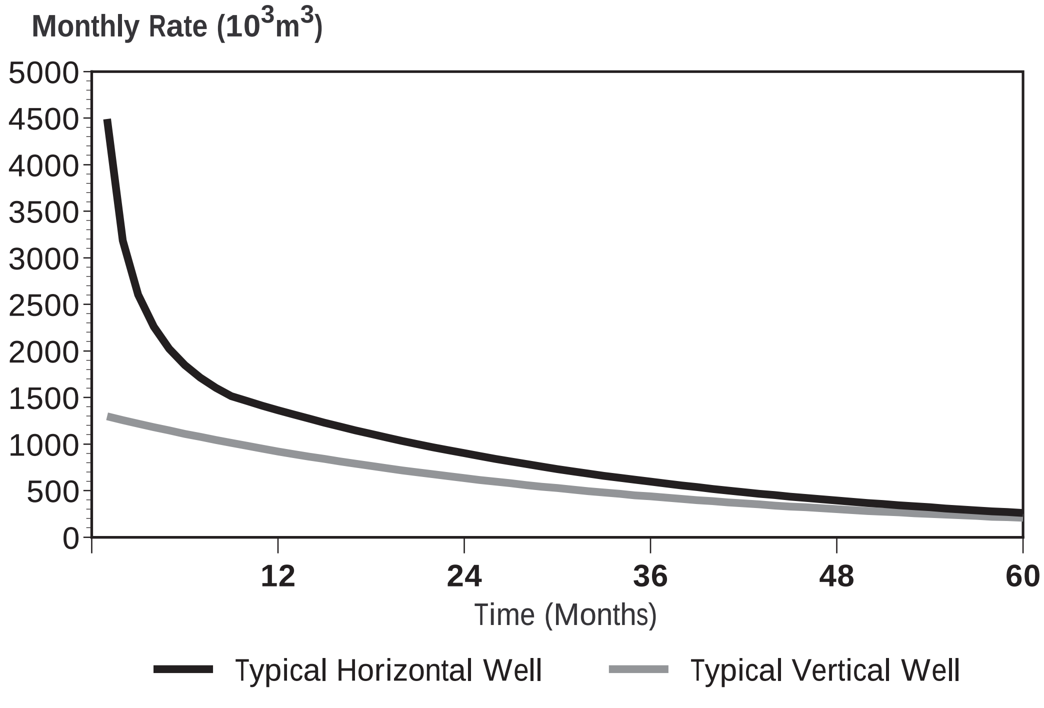
Gunnel Field - Jean Marie A Pool

The first well in this pool, Gunnel b-083-C/094-I-13, was drilled in 1959, but was not completed until 1979. Full scale development of this pool did not commence until 1994/1995. A total of 16 (9 horizontal and 7 vertical) gas wells have been drilled, 12 of which are currently producing. The seven producing horizontal wells were placed on production in 1997 or 1998, while the production from vertical wells began in 1994. The horizontal wells have contributed 112 $10^6 m^3$, or 45 per cent of the total production. One particular vertical well, Gunnel a-073-F/094-I-13, has produced about 22 per cent of the total cumulative production due to its exceptionally thick net pay of 16.5 metres, almost twice that of the pool's average pay. Its initial flow rate of 144 $10^3 m^3$/operating day is similar to the 120-130 $10^3 m^3$/operating day range for a typical horizontal well in this pool.

The analysis indicates that the initial monthly gas rate for a typical horizontal well is about 4 500 $10^3 m^3$/month, or about 3.5 times the 1 300 $10^3 m^3$/month of a typical vertical well (Figure 7). However, the production rate declines rapidly. Based on this information, the cumulative production for a horizontal well is expected to be in the 60-240 $10^6 m^3$ range compared to 15-70 $10^6 m^3$ range for a typical vertical well.

FIGURE 7

Gunnel Jean Marie A



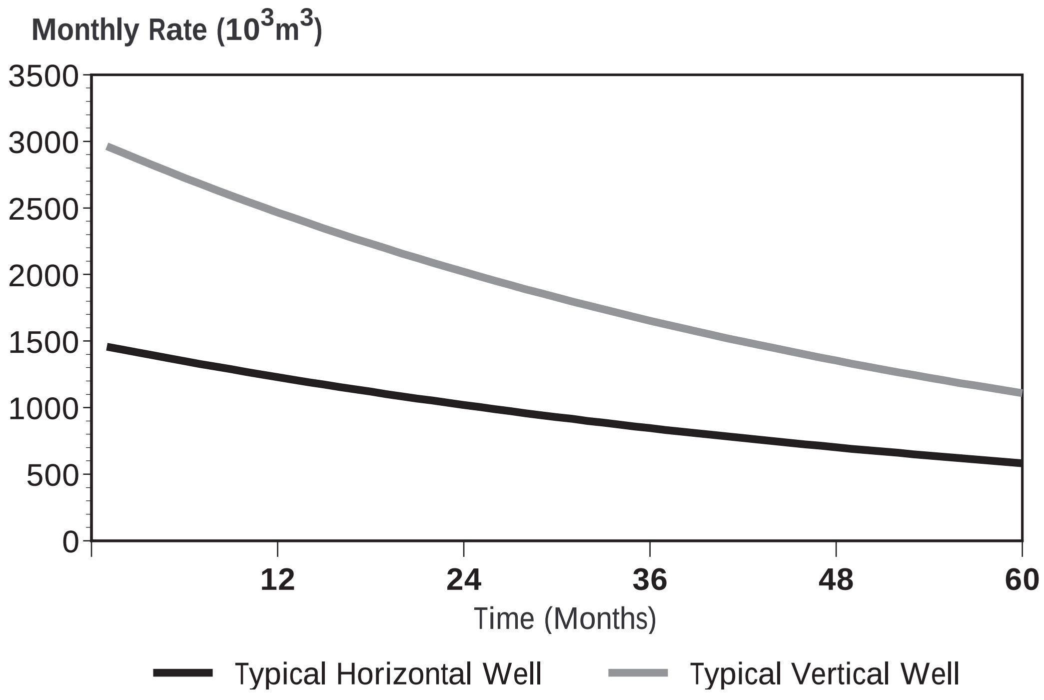
Helmet North Field - Jean Marie A Pool

Gas production in this pool began in 1978. There are now 38 vertical wells and seven horizontal wells drilled. Horizontal technology was first tried in 1988 but resulted in an abandoned well. The technology was subsequently applied successfully with six development wells drilled between 1993 and 1994. No vertical wells have been drilled or completed since 1993. Altogether, the six horizontal wells have produced 215 $10^6 m^3$ of raw gas or about 10 per cent of the raw gas produced from this pool since January 1994, when the first horizontal well was placed on production. Furthermore, production performance suggests that these horizontal wells have increased the overall cumulative recovery by about four per cent.

Analysis indicates that the initial monthly rate for a typical horizontal well was about half the initial rate of 3 000 $10^3 m^3$/month for a typical vertical well (Figure 8). The overall recovery from a typical horizontal well in this pool would be about 44 per cent of a vertical well recovery. However, it should be noted that these wells were usually drilled around the pool boundaries where vertical wells were not attempted due to the high water saturation of the reservoir. The pay thickness, on average, is less than half of the value in the vertical wells. Therefore, the comparison of the performances of the horizontal wells to that of vertical wells may not be conclusive. For example, horizontal well N Helmet b-071-G/094-P-10 and vertical well N Helmet a-071-G/094-P-10 showed the same values of net pay and porosity. However, the horizontal well has produced 45.2 $10^6 m^3$ of raw gas, or 2.5 times the vertical well production. Also, horizontal wells N Helmet c-A057-A/094-P-15 and N Helmet a-057-B/094-P-15, and vertical well N Helmet b-068-D/094-P-16 are located near each other and yet cumulative production from a-057-B is about five times that of the vertical well. The overall cumulative gas production is expected to be in the 33-67 $10^6 m^3$ range compared to the 80-270 $10^6 m^3$ range predicted for a typical vertical well. It is noted that a horizontal well with similar geological and production characteristics as a vertical well should achieve an overall production in the range of 100-470 $10^6 m^3$. Therefore, a vertical well may be less productive in this pool than a horizontal well.

FIGURE 8

Helmet North Jean Marie A



Jedney Field - Baldonnel/Upper Charlie Lake A Pool

Gas production from vertical wells in this pool began in 1959. Prior to the first horizontal well, Jedney a-039-F/094-G-08, being placed on production in January 1994, a total of 6 721 10^6m^3 of raw gas had been produced. No vertical wells have been placed on production since 1994. A total of 12 producing horizontal wells (three in the Petro-Canada Project and nine in the Norcen Energy Project) have been drilled in the northeast portion of the pool.

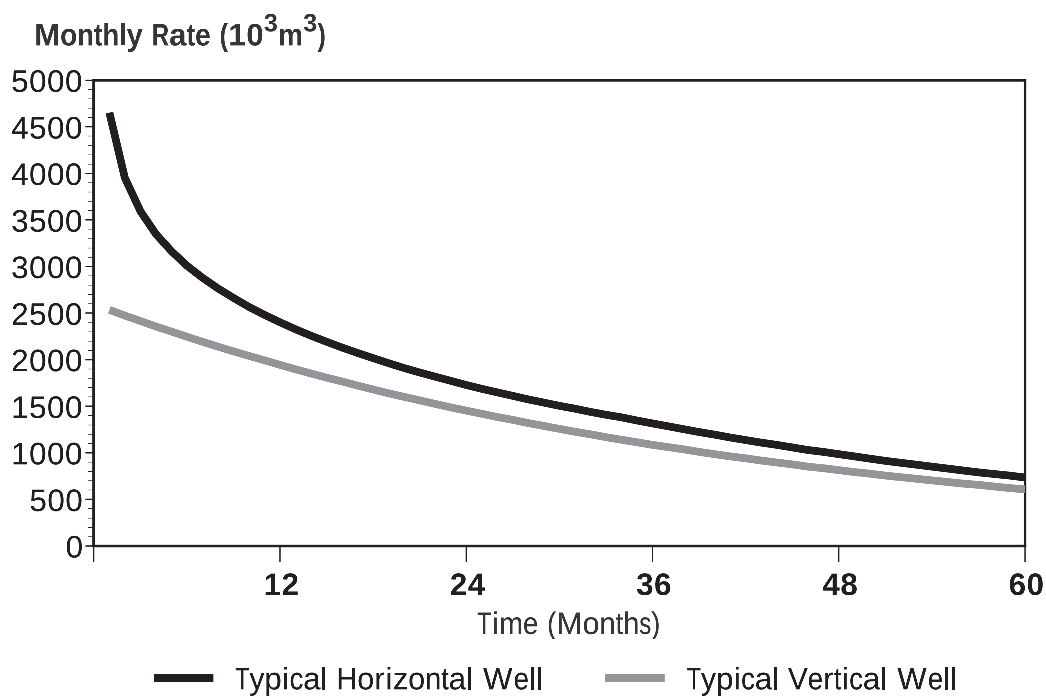
The nine horizontal wells in the Norcen Energy Project have produced 209 10^6m^3 of the 952 10^6m^3 total gas produced. Note that vertical well Jedney b-062-E/094-G-08 alone, has produced more than 520 10^6m^3 of raw gas due to its thicker net pay and higher porosity. Also, horizontal well N Bubbles a-099-F/094-G-08 has produced more than 113 10^6m^3 of raw gas or about 50 per cent more than a nearby vertical well N Bubbles d-A099-F/094-G-08.

The three horizontal wells in the Petro-Canada Project have produced 277 10^6m^3 of the 7 279 10^6m^3 total gas production from this project. Twenty of the 22 vertical wells have been on production since the mid-1960s. It is noted that Jedney d-009-F/094-G-08 produced more raw gas in a shorter time period than a nearby vertical well Jedney c-008-F/094-G-08.

The analysis suggests that the initial monthly rate for a typical horizontal well is about 4 600 10^3m^3/month or 80 per cent higher than the 2 500 10^3m^3/month for a typical vertical well (Figure 9). A typical horizontal well is expected to produce 80-310 10^6m^3 of raw gas versus the expected recovery of 35-170 10^6m^3 of raw gas for a typical vertical well.

FIGURE 9

Jedney Baldonnel/Upper Charlie Lake A



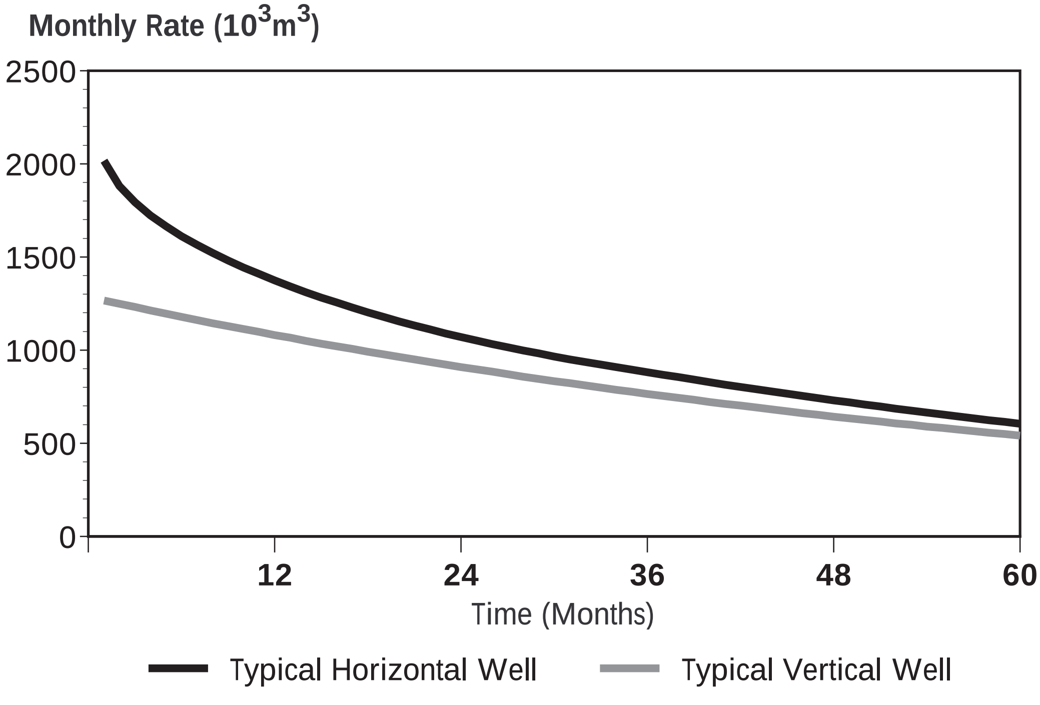
Midwinter Field - Jean Marie A Pool

Gas production from this pool began in 1994 when both vertical wells and horizontal wells were placed on production. There are seven producing horizontal and six producing vertical wells in this pool. Four of the vertical wells were drilled in the 1980s and all seven horizontal wells were drilled after 1993. The horizontal wells have produced more than 83 per cent of the total raw gas from this pool. Horizontal well Midwinter a-041-D/094-P-15 and vertical well Midwinter d-059-C/094-P-15 came on production in early 1994 and have similar reservoir characteristics. However, the horizontal well produced about 57.3 $10^6 m^3$ of raw gas compared to 24.7 $10^6 m^3$ produced by the vertical well.

The results of our analysis suggests that with similar reservoir characteristics, a horizontal well will outperform a vertical well in this pool (Figure 10). The initial monthly production rate for a typical horizontal well is about 2 000 $10^3 m^3$/month compared to 460 $10^3 m^3$/month for a typical vertical well and cumulative production would be in the range of 50-170 $10^6 m^3$ for a typical horizontal well versus 35-135 $10^6 m^3$ for a typical vertical well.

FIGURE 10

Midwinter Jean Marie A



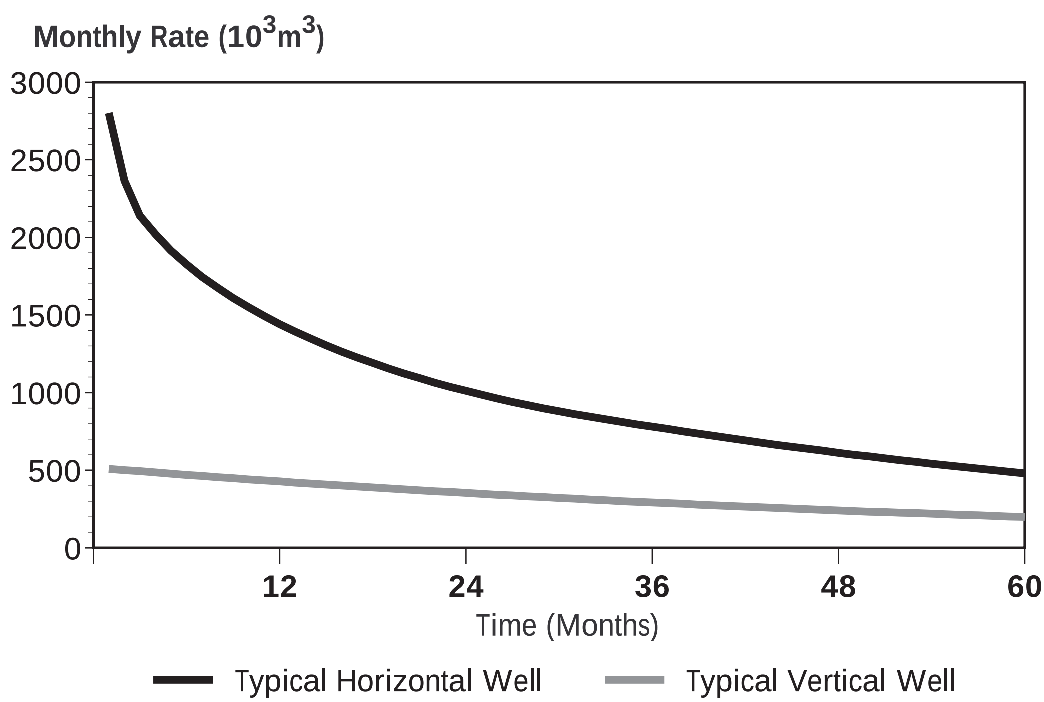
Midwinter Field - Jean Marie C Pool

This pool was discovered in 1979 but development did not begin until 1994. Both the Midwinter Jean Marie A and C pools have high average water saturations (above 40 per cent). The Jean Marie C pool is currently producing from three vertical and 16 horizontal wells. Note that all three vertical wells were drilled in 1995. The cumulative production as well as the average production from these three wells is well below the average for the horizontal wells. Five additional horizontal wells have been drilled and produced. Production from these five wells exceeds 117.5 10^6m^3, more than three times of the 34.3 10^6m^3 of gas produced by the three vertical wells.

The analysis suggests that the initial monthly gas rate for a typical horizontal well is approximately 2 800 10^3m^3/month, which declines by half to 1 400 10^3m^3/month after one year and to about 770 10^3m^3/month after three years of production (Figure 11). The initial monthly gas rate for a typical vertical well would be about 500 10^3m^3/month, which declines to about 400 10^3m^3/month after one year and to 290 10^3m^3/month after three years. The cumulative recovery for a typical horizontal well would be in the range of 40-200 10^6m^3, compared to 5-45 10^6m^3 for a typical vertical well.

FIGURE 11

Midwinter Jean Marie C



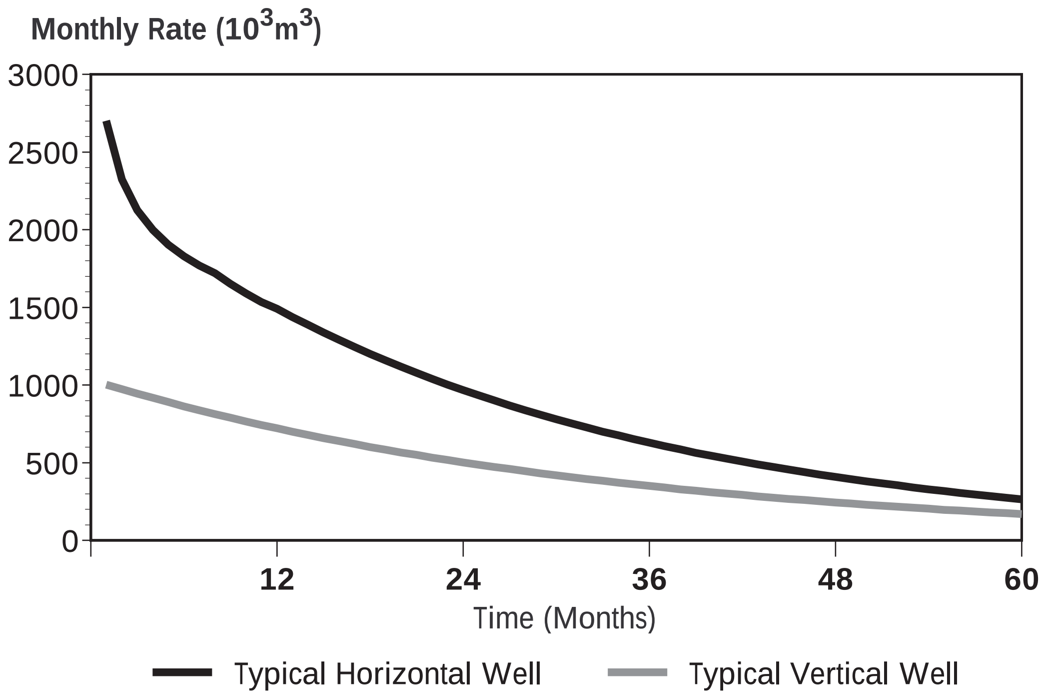
Peggo Field - Jean Marie A Pool

There are 23 horizontal and 26 vertical wells in this pool. Twenty of the 44 producing wells are horizontal. A total of 351 $10^6 m^3$ of gas was produced from 14 vertical wells between 1989 and 1994 before horizontal wells came on stream. From 1994 to August 1998, an additional 570 $10^6 m^3$ of gas was produced from the vertical wells. Thirty-six per cent of this additional gas was produced by twelve new vertical wells. During the same time, 1 073 $10^6 m^3$ of gas was produced from the 23 horizontal wells. It is observed that horizontal wells were drilled where net pay values are generally lower than those of the vertical wells.

The initial monthly gas rate for a typical horizontal well is approximately 2 700 $10^3 m^3$/month, which declines to about 1 500 $10^3 m^3$/month after one year and to about 900 $10^3 m^3$/month after three years (Figure 12). The initial monthly gas rate for a typical vertical well is about 1 000 $10^3 m^3$/month which declines to about 700 $10^3 m^3$/month after one year and to about 340 $10^3 m^3$/month after three years. The overall recovery for a horizontal well is anticipated in the 40-130 $10^6 m^3$ range. This range of values is similar to the values for the Midwinter Jean Marie pools and twice the anticipated 15-65 $10^6 m^3$ recovery for a typical vertical well.

FIGURE 12

Peggo Jean Marie A



Yoyo Field - Pine Point A Pool

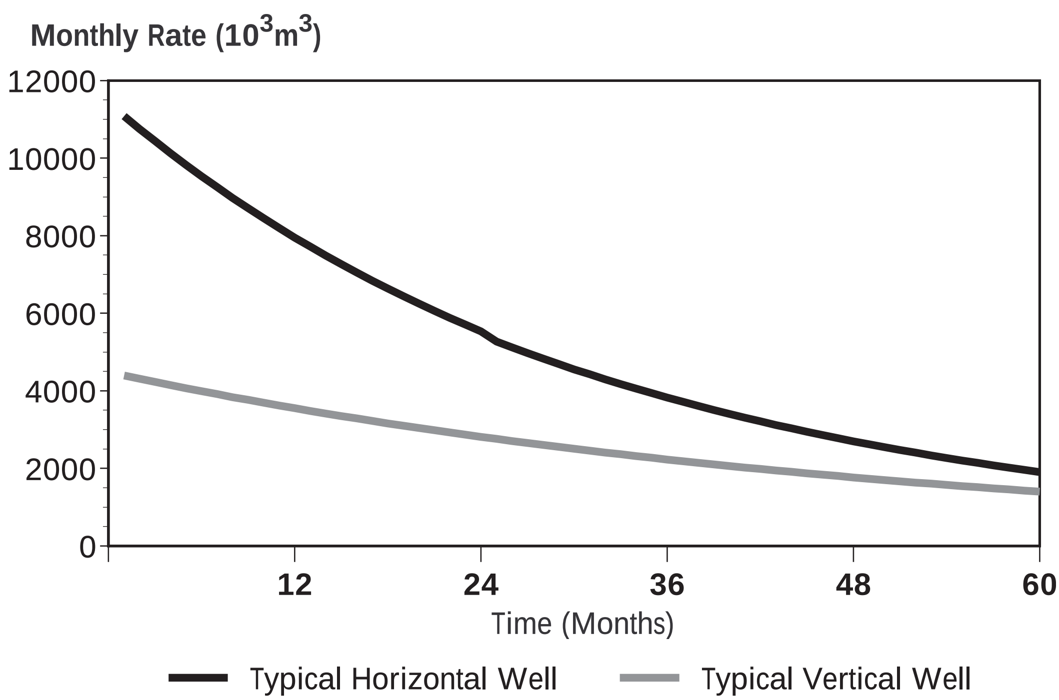
Gas production from this pool started in 1968. There are still 17 (6 horizontal and 11 vertical) wells on production. More than 90 per cent of the cumulative production to date (40 589 10^6m^3) was produced from the 27 vertical wells before horizontal wells were placed on production in 1994. Since 1994, a total of 3 869 10^6m^3 of raw gas has been produced. This gas production came from six horizontal wells (1 703 10^6m^3), three new vertical wells (116 10^6m^3) and eight old vertical wells (2 050 10^6m^3). A total of 16 vertical wells have been abandoned due to a combination of low monthly rates and high WGRs. Most of these wells were abandoned after the wells could not sustain consistent production rates above 1 000 10^3m^3/month.

All six horizontal wells were re-entry wells. Each was completed in a wellbore after a producing vertical well was suspended. Horizontal well, Yoyo c-032-I/094-I-13 was re-completed in 1995 after the vertical well was abandoned in 1993. It has produced about 346 10^6m^3 of raw gas in less than three years, an amount that the vertical wells, at their historical production rates, would have produced in five years. Yoyo a-002-L/094-I-14 was re-completed in 1994 and has produced a total of 270 10^6m^3 of raw gas in four years. The vertical wellbore had produced 3 272 10^6m^3in 23 years. In four years, Yoyo d-007-L/094-I-14 and c-020-L/094-I-14 have produced 491 10^6m^3 and 277 10^6m^3 of raw gas, respectively. Yoyo c-018-L/094-I-14 produced 115 10^6m^3 in two years and Yoyo c-A018-L/094-I-14 produced 128 10^6m^3 in three years.

Based on well performances, the analysis suggests that the initial monthly gas rate for a typical horizontal well is approximately 11 000 10^3m^3/month, which declines to about 7 700 10^3m^3/month after one year and to about 3 700 10^3m^3/month after three years (Figure 13). The initial monthly gas rate for a typical vertical well is about 4 400 10^3m^3/month, which declines to 3 500 10^3m^3/month after one year and to 2 200 10^3m^3/month after three years. The recovery for a horizontal well is anticipated to be 180-680 10^6m^3. This estimate is twice the anticipated 100-210 10^6m^3 for a typical vertical well.

F I G U R E 1 3

Yoho Pine Point A



ECONOMICS

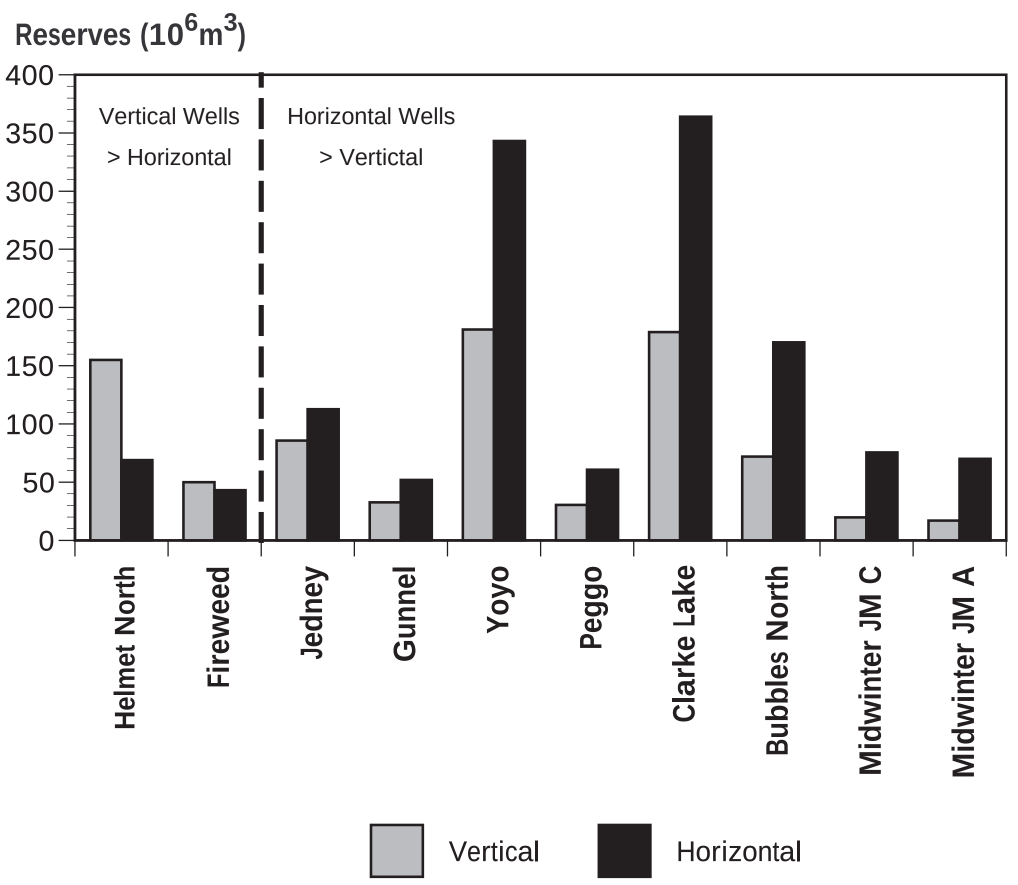
The economic viability of a typical vertical and horizontal gas well is evaluated using the concept of full-cycle supply cost at the plantgate, which expresses all of the costs associated with the gas exploration and development as an average cost per unit of production. The main cost components are: capital costs associated with exploration and development, production and operating costs, federal and provincial taxes, resource royalties and minimum required rate of return (ten per cent). The supply costs were calculated using the Petroleum Economic Evaluation Program (PEEP[1]) developed by Merak Projects Ltd.

The capital cost data was determined by examining historical costs for both the vertical and horizontal wells within the study areas. The average drilling and completion costs for a vertical well within these ten pools ranges from about $1 million to $1.2 million. For a horizontal well, the costs range from $1.4 million to $1.7 million, or approximately 1.5 times the cost of a vertical well. The average operating costs range from $8.65 to $17.49/10^3^m^3^ of gas.

From the above analyses, it appears that horizontal wells in Helmet North and Fireweed do not recover more gas than the vertical wells (Figure 14). In the other eight pools, it is expected that a

FIGURE 14

Comparison of Estimated Well Reserves by Well Type



[1] Discussion of this program and the concept of supply costs can be found in Section 7.1.6 of *NEB's Supply and Demand 1993-2010.*

horizontal well will increase overall recovery ranging from a low of 20 per cent to a high of about 200 per cent. The following table shows the comparison of expected reserves and supply costs of typical horizontal wells to typical vertical wells (Table 3). On a cost basis at the plantgate, all vertical wells, with the exception of those in the Midwinter Jean Marie A (Figure 15) are economically feasible at a $\$70/10^6m^3$ gas price. All horizontal wells are also economically feasible at a $\$70/10^6m^3$ gas price. In order to justify the higher capital costs of horizontal wells, it is necessary that the horizontal well recover at least 35 per cent more than a vertical well in the same pool. In this study, that occurred in seven of the ten pools.

FIGURE 15

Supply Costs

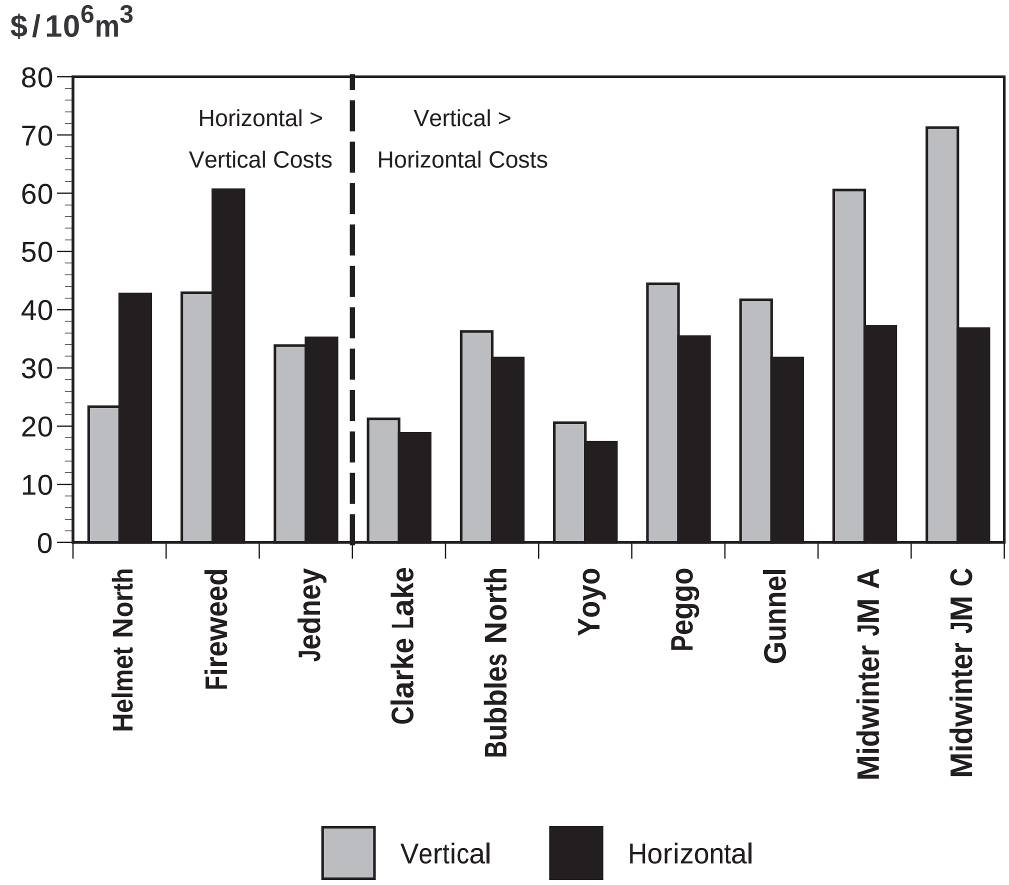


TABLE 3

Expected Reserves versus Supply Cost

	Reserves (10^3m^3)			Supply Costs ($\$/10^3m^3$)		
	Vertical	**Horizontal**	**Horizontal to Vertical Ratio**	**Vertical**	**Horizontal**	**Horizontal to Vertical Ratio**
Bubbles North	72	170	2.38	36.28	31.70	0.87
Clarke Lake	179	364	2.03	21.25	18.77	0.88
Fireweed	51	44	0.87	42.89	60.63	1.41
Gunnel	36	58	1.61	41.71	31.70	0.76
Helmet North	155	69	0.45	23.36	42.69	1.83
Jedney	90	117	1.3	33.83	35.17	1.04
Midwinter JM A	24	82	3.48	60.58	37.14	0.61
Midwinter JM C	17	80	4.57	71.27	36.74	0.52
Peggo	30	58	1.91	44.43	35.36	0.80
Yoyo	209	363	1.74	20.59	17.26	0.84

CONCLUSIONS

The results of this study suggest that horizontal gas well projects are generally more productive than vertical wells and increase the recovery efficiency factor for mature gas reservoirs. Horizontal drilling is usually undertaken to achieve important technical objectives related to specific characteristics of a target reservoir. These characteristics typically involve the reservoir rock's permeability, increased wellbore surface area within the producing interval, and/or the expected propensity of the reservoir to develop water coning either from other parts of the reservoir or from adjacent rocks.

The productive permeability in a horizontal well is generally a combination of fracture permeability and matrix permeability. Horizontal wells drilled to intersect vertical fractures have typically demonstrated much higher initial production rates than nearby vertical wells. Each horizontal well proposal must be carefully analyzed to optimize its drilling and completion plans because horizontal wells are more costly than vertical wells.

By far, the most intensive application of horizontal drilling has been in the Jean Marie Formation. At year-end 1998, 81 horizontal gas wells had been drilled into this formation. Jean Marie horizontal wells, with the exception of the six horizontal wells in Helmet North, are more productive than the conventional offsetting vertical wells.

In successful horizontal drilling applications, the better performance of gas wells is generally due to the occurrence of a number of factors. First, operators are able to develop a reservoir with a smaller number of horizontal wells, since each well can drain a larger rock volume about its bore than a vertical well. Second, a horizontal well produces at rates several times greater than a vertical well. A faster producing rate translates to a higher recovery and higher rate of return than a vertical project would achieve. It is also expected that a successful horizontal well will lower the supply cost by at least 10 per cent. Third, use of a horizontal well may preclude or significantly delay the onset of production problems.

APPENDICES

APPENDIX 1

Horizontal Gas Well Operators in British Columbia (Year-End 1998)

	ABD	GAS	Potential	Susp	Testing	Total
Anderson Expl Ltd.		1				1
Anderson Rsrcs Ltd.		1				1
Beau Cda Expl Ltd.		16	1		2	19
Berkley Petrl Corp.	1	12	3	4		20
Blue Range Rsrc Corp.		8		1		9
Cabre Expl Ltd.		1				1
Cannat Rsrcs Inc.	1	4	2	1		8
Cdn Nat Rsrcs Ltd.		2	1	4		7
Crestar Enrg Inc.	1	2		1		4
Home Oil Comp Ltd.	1	8		1	1	11
Interaction Rsrcs Ltd.				1		1
Intl Colin Enrg Corp.	1					1
Jet Enrg Corp.			3			3
Mobil Oil Cda	2	4				6
Numac Enrg Inc.		1				1
Pan East Petrl Corp.		5				5
Penn West Petrl Ltd.		6				6
Petro-Cda O&G	3	36	8	4	1	52
Pioneer Nat Rsrcs Cda Inc.			2			2
Poco Petrls Ltd.	6	3	1	3		13
Pursuit Rsrcs Corp.				2		2
Ranger Oil Ltd.		35	3	3		41
Remington Enrg Ltd.		7	3		2	12
Shiningbank Enrg Ltd.			1			1
Summit Rsrcs Ltd.		7				7
Suncor Enrg Inc.		2	1			3
Talisman Enrg Inc.			1	1		2
Tarragon O&G Ltd.		2	3	3		8
Union Pacific Rsrcs Inc.		10				10
Unocal Cda Ltd.		4				4
Wascana Enrg Inc.	1	5		1		7
Total	**17**	**179**	**32**	**30**	**6**	**268**

APPENDIX 2 PART A

Well Status List of Horizontal Gas Wells in British Columbia (Year-End 1998)

POOL	ABD	GAS Inject	GAS Well	Potential Multizone GAS	Potential GAS	Susp GAS	Testing GAS	ABD GAS
ADSETT SLAVE POINT A						1		1
AITKN CK GETHING A		2	2					4
BBBLES N BLDL/U C LK A			4					4
BCK CK W BALDONNEL F			2					2
BEG BALDONNEL A			4					4
BEG BALDONNEL C			1			1		2
BEG BALDONNEL E							1	1
BIRCH BALDONNEL A			1					1
BIRCH BALDONNEL H						1		1
BIRLY CK BALDONNEL			1					1
BIRLY CK BALDONNEL B			1					1
BLLMSE W PRDNT-BLDNL D	1		1					2
BOULDER PRDNT-BLDNL B			1					1
CACHE CK DOIG G							1	1
CLRKE LK SLAVE POINT A	1		7					8
EVIE BNK PINE POINT	1							1
EVIE BNK SLAVE POINT A	1							1
F S J SE BALDONNEL A			2					2
F S J SE HALFWAY A			1					1
F ST JHN BALDONNEL B			1					1
F ST JHN L BELLOY A			1					1
FIREWEED BALDONNEL E			4					4
FIREWEED BLUESKY			1					1
FIREWEED DUNLEVY			1					1
GUNNEL JEAN MARIE A	1		7			1		9
GUNNEL JEAN MARIE B			2					2
HELMET JEAN MARIE			2					2
HELMET JEAN MARIE A			1					1
HELMET JEAN MARIE F			4					4
HELMET N JEAN MARIE A			6			1		7
HOFFARD SLAVE POINT D			1					1
JEDNEY BLDL/U C LK A			11					11

(Continued)

APPENDIX 2 PART B

Well Status List of Horizontal Gas Wells in British Columbia (Year-End 1998)

POOL	ABD	GAS Inject	GAS Well	Potential Multizone GAS	Potential GAS	Susp GAS	Testing GAS	ABD GAS
KTCHO LK SLAVE POINT A						1		1
KTH LK E SLAVE POINT C			1					1
LPRSE CK BLDL/U C LK A			2					2
MDWINTER JEAN MARIE			1					1
MDWINTER JEAN MARIE A			6					6
MDWINTER JEAN MARIE C			15					15
MURRAY BALDONNEL B						1		1
MURRAY PRDNT-BLDNL B	1					1		2
NIG CK BALDONNEL A			2					2
OTH AREA JEAN MARIE			6				1	7
OTH AREA SLAVE POINT	1							1
OTH AREA UNKNOWN			2					2
PARKLAND WABAMUN A			1					1
PEGGO JEAN MARIE			1					1
PEGGO JEAN MARIE A	1		20			1	1	23
PEGGO JEAN MARIE B			2					2
PICKELL BALDONNEL						1		1
PRSPATOU BALDONNEL			1					1
SAHTANEH PINE POINT C	1					1		2
SIERRA PINE POINT A			4					4
SIKANNI DEBOLT A			1					1
SIPHON DUNLEVY A			1					1
STDDRT W DOIG E		1						1
STDDRT W DUNLEVY B			1					1
STDDRT W DUNLEVY D			1					1
STDDRT W GETHING			1					1
STDDRT W HALFWAY C			1					1
TMMY LKS HALFWAY A			1					1
TSEA JEAN MARIE A			1					1
YOYO PINE POINT A			6					6
YOYO SLAVE POINT A			1					1
UNIDENTIFIED						1		1
Total	**17**	**3**	**179**	**1**	**32**	**30**	**6**	**268**

APPENDIX 3

Horizontal Gas Wells in B.C.

Status	Count	Cum Gas ($10^6 m^3$)	Cum Oil (m^3)	Cum Water ($10^3 m^3$)
Abandoned GAS	17	239.8	0.4	20.0
GAS Inject	3	169.8	14 649.0	0.1
GAS Well	179	9 430.7	8 435.1	418.3
Potent Multi-zone GAS	1			
Potential GAS	32			
Suspended GAS	30	322.2	284.3	6.8
Testing GAS	6	62.1	1 626.6	0.1
Total	**268**	**10 224.6**	**24 995.4**	**445.3**

APPENDIX 4

Production Profile for B.C. Gas Wells

Expected Monthly Rate (10^3m^3/month)

		Initial	After 1 yr	After 2 yrs	After 3 yrs
Bubbles North Baldonnel/Upper Charlie Lake A	vertical	1 327	1 240	1 159	1 084
	horizontal	4 848	2 851	2 402	2 167
	ratio	3.7	2.3	2.1	2
Clarke Lake Slave Point A	vertical	4 000	3 200	2 644	2 145
	horizontal	12 100	7 600	55 904	4 345
	ratio	3	2.4	2.2	2.2
Fireweed Baldonnel E	vertical	1 670	1 257	923	609
	horizontal	2 887	1 131	659	435
	ratio	1.7	0.9	0.7	0.7
Gunnel Jean Marie A	vertical	1 300	900	600	420
	horizontal	4 500	1 250	850	560
	ratio	3.5	1.4	1.4	1.3
Helmet North Jean Marie A	vertical	3 000	2 650	2 350	2 100
	horizontal	1 450	1 210	1 000	830
	ratio	0.5	0.5	0.4	0.4
Jedney Baldonnel/Upper Charlie Lake A	vertical	2 500	1 900	1 400	1 050
	horizontal	4 650	2 300	1 700	1 300
	ratio	1.8	1.2	1.2	1.2
Midwinter Jean Marie A	vertical	688	483	403	341
	horizontal	3 070	1 588	1 168	925
	ratio	4.5	3.3	2.9	2.7
Midwinter Jean Marie C	vertical	487	414	334	254
	horizontal	3 260	1 512	1 042	766
	ratio	6.6	3.7	3.1	3
Peggo Jean Marie A	vertical	1 000	700	487	350
	horizontal	2 700	1 440	934	629
	ratio	2.2	2.1	1.9	1.9
Yoyo Pine Point A	vertical	4 400	3 480	2 800	2 200
	horizontal	11 000	7 710	5 500	3 700
	ratio	2.5	2.2	1.9	1.7

APPENDIX 5

Recovery Profile for B.C. Gas Wells

		Expected Recovery ($10^3 m^3$/month)			
		After 1 yr	**After 2 yrs**	**After 3 yrs**	**Cumulative**
Bubbles North Baldonnel/Upper Charlie Lake A	vertical	15.4	29.9	43.4	71.5
	horizontal	42.5	73.9	101.3	170.3
	ratio	2.8	2.5	2.3	2.4
Clarke Lake Slave Point A	vertical	43.4	78.5	107	178.8
	horizontal	114	194.1	257	363.3
	ratio	2.6	2.5	2.4	2
Fireweed Baldonnel E	vertical	17.5	30.2	39.7	56.6
	horizontal	20.8	30.8	37.2	49.8
	ratio	1.2	1	0.9	0.9
Gunnel Jean Marie A	vertical	13.2	22.3	28.5	35.8
	horizontal	25.4	38.2	46.5	57.6
	ratio	1.9	1.7	1.6	1.6
Helmet North Jean Marie A	vertical	32.5	59.1	80.9	155.4
	horizontal	16.1	29.4	40.5	68.9
	ratio	0.5	0.5	0.5	0.5
Jedney Baldonnel/Upper Charlie Lake A	vertical	26.7	46.7	61.7	89.6
	horizontal	37.5	61.5	79.5	116.7
	ratio	1.4	1.3	1.3	1.3
Midwinter Jean Marie A	vertical	6.5	11.1	11.5	23.5
	horizontal	24.9	40.9	43.2	81.9
	ratio	3.8	3.7	3.8	2.9
Midwinter Jean Marie C	vertical	5.6	10.2	14.1	17.4
	horizontal	24.9	39.7	50.3	70.9
	ratio	4.4	3.9	3.6	4.1
Peggo Jean Marie A	vertical	10.3	17.4	22.4	27.4
	horizontal	22.9	36.9	46.2	57.6
	ratio	2.2	2.1	2.1	2.1
Yoyo Pine Point A	vertical	15.4	29.9	43.4	71.5
	horizontal	42.5	73.9	101.3	170.3
	ratio	2.8	2.5	2.3	2.4

APPENDIX 6

Expected Gas Well Recovery (10^6m^3)

	Vertical				**Horizontal**			
	Min	Mode	Mean	Max	Min	Mode	Mean	Max
Bubbles North	60	112	116	211	116	220	224	427
Clarke Lake	54	131	169	362	264	495	503	959
Fireweed	32	60	62	113	40	77	78	147
Gunnel	16	30	36	71	58	101	123	238
Helmet North	81	129	154	271	33	72	67	124
Jedney	35	69	86	172	82	160	162	309
Midwinter JM A	24	77	73	134	48	92	89	176
Midwinter JM C	5	17	21	46	46	108	109	196
Peggo	15	31	30	64	37	68	72	132
Yoyo Pine Pt A	98	197	205	372	182	393	357	684

APPENDIX 7

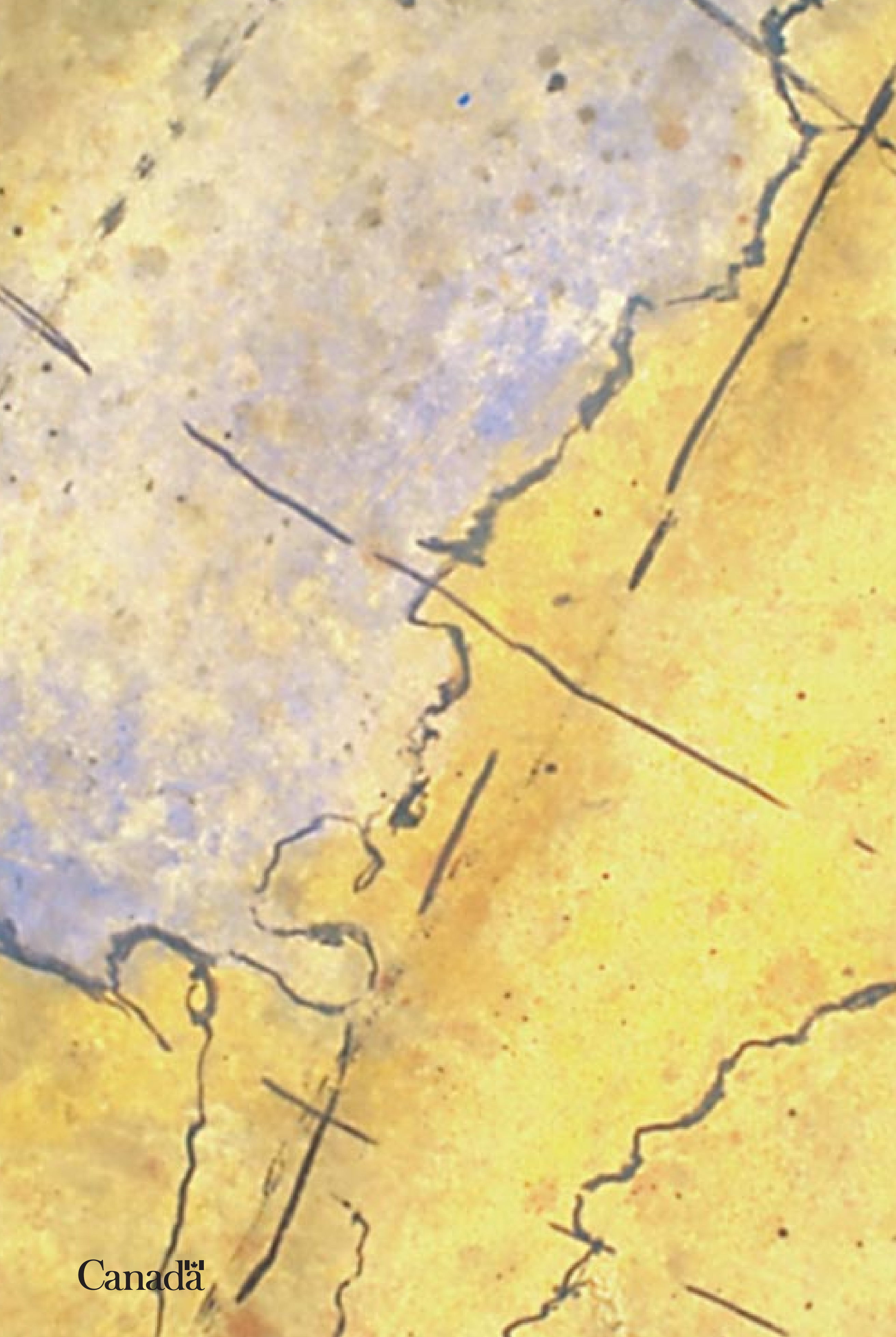
Re-Completed Horizontal Gas Wells in B.C.

Well ID	**Spud Date**	**Completion Date**	**Field Name**	**Pool Name**	**Cum Gas (10^6m^3)**	**Cum Water (10^3m^3)**
200/b-028-L/094-I-14/02	2/27/64	10/15/96	YOYO	PINE POINT A	115.8	25.3
200/d-013-J/094-J-10/02	12/4/65	2/9/96	CLRKE LK	SLAVE POINT	437.7	15.9
200/c-006-L/094-I-14/02	12/22/66	3/11/94	YOYO	PINE POINT A	491.4	14
200/a-002-L/094-I-14/02	1/21/68	8/17/94	YOYO	PINE POINT A	269.9	105.1
200/d-094-I/094-J-10/02	1/19/72	8/25/97	CLRKE LK	SLAVE POINT	16	6.6
200/c-036-I/094-I-13/03	12/8/75	12/12/97	YOYO	SLAVE POINT	2.1	0.4
200/d-007-J/094-I-14/03	12/15/75	3/28/96	KTH LK E	SLAVE POINT	24	2.8
200/b-032-I/094-I-13/02	1/21/76	10/7/95	YOYO	PINE POINT A	345.5	24.8
200/b-030-L/094-I-14/02	1/19/78	8/20/94	YOYO	PINE POINT A	276.9	104.1
200/d-019-L/094-I-14/02	1/8/79	7/21/95	YOYO	PINE POINT A	203.5	12.9
102/02-26-087-21W6/03	10/28/85	9/4/96	STDDRT	DUNLEVY B	107.6	0.6
Total					**2 290.3**	**312.4**

APPENDIX 8

B.C. Producing Horizontal Gas Wells by Pool

Pool Name	Count	Cum Gas ($10^6 m^3$)	Cum Oil ($10^6 m^3$)	Cum Water ($10^6 m^3$)
BALDONNEL	2	9.4	0	0.1
BALDONNEL A	9	238.4	0.8	11.4
BALDONNEL B	2	9.1	0	0.6
BALDONNEL C	1	40.2	0	0.7
BALDONNEL E	4	153	0	15.2
BALDONNEL F	2	72.5	0.8	0.3
BLDL/U C LK A	17	1 147.9	0.8	25.8
BLUESKY	1	11.5	0	0.4
DEBOLT A	1	14.1	0	0
DUNLEVY	1	13.7	0	0.8
DUNLEVY A	1	29.4	0	2.5
DUNLEVY B	1	107.6	0	0.6
DUNLEVY D	1	16.4	0	2.3
GETHING	1	0.9	0	0
GETHING A	2	1 181.5	0	0.2
HALFWAY A	2	10	0	0.1
HALFWAY C	1	68.5	0	0.5
JEAN MARIE	10	48.7	0.2	0.2
JEAN MARIE A	41	1 774.4	5.8	10.3
JEAN MARIE B	4	25.2	0	0.2
JEAN MARIE C	15	470.9	0.2	2.2
JEAN MARIE F	4	68.3	0.4	0.1
LWR BELLOY A	1	1.3	0	0
PINE POINT A	10	2 218.9	0	290.9
PRDNT-BLDNL B	1	441.1	0	0.7
PRDNT-BLDNL D	1	109.5	0	8
SLAVE POINT A	8	983	0	40.5
SLAVE POINT C	1	24	0	2.8
SLAVE POINT D	1	54.9	0	0.8
UNKNOWN	2	17.8	0.1	0
WABAMUN A	1	68.6	0	0.3
Total	**149**	**9 430.7**	**8.4**	**418.3**



Canada