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Horizontal Wells for the Recovery of Oil, Gas and Bitumen

Petroleum Society Monograph Number 2

by Roger M. Butler, University of Calgary

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by
Roger M. Butler

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PREFACE

For the last eighteen years, the author has been intimately involved with the use of horizontal wells for the production of petroleum. This preoccupation started simply with his concept of the steam-assisted gravity drainage (SAGD) process he wished to develop for the recovery of bitumen from the Cold Lake reservoir. The proposed approach resembled the recovery of salt by solution mining where fresh water is injected into a cavern that grows by solution as the salt at its walls dissolves. The brine falls along the surface to be gathered by a well completed below. In SAGD, steam is injected into the tar sand to form a growing steam chamber. It condenses at the surface of the chamber and heats the adjacent bitumen. The heated bitumen falls, together with the condensate from the steam, along the surface of the chamber and is collected, still hot, at a lower well.

The process was to proceed by progressively "melting" and removing layers of bitumen, thus letting the steam-saturated chamber grow – rather like removing the layers from an onion, but inside out.

There was one major problem with the idea. Calculations showed the rate to be too slow to be economic for two reasons:

1. the low thermal conductivity of tar sand, which limits the rate of heat transfer, and,
2. the high resistance to the flow of the heated bitumen as it converged to the lower well.

The restriction to flow caused by the convergence of the streamlines in the vicinity of production wells is the major problem of petroleum engineering. It limits the production rates from conventional wells and is the main reason oil fields, particularly heavy oil fields, require so many wells.

The technique for overcoming the problem for SAGD that came to mind, and the one that has since been found to be a practical solution, was the extension of the wellbore as a horizontal drain extending over a considerable distance near the bottom of the reservoir. The idea was that the low drainage rate for a vertical well could be multiplied many times by extending the collection surface and that this might make the process economic. The author adopted this concept with fervour and could be heard telling the few who would listen about farmers draining their fields with weeping tiles rather than with multiple vertical well points. For awhile, he even referred to horizontal wells for SAGD as weeping wells for, perhaps, more reasons than one. It has been a surprise to the author to see this little flicker of an idea grow and become accepted. Possibly it is now self-evident, but there was a time when there were sceptics.

Stemming from the original analysis and model testing of SAGD by the author and his colleagues at Imperial Oil (Hing Lo, Gordon McNab, Dave Stephens and others), a demonstration pilot – the first of the modern horizontal wells – was built at Cold Lake in 1978. It was a bold investment on the part of Imperial Oil's management and was successful. There is more about this in Chapter 11.

The advantages horizontal wells offered – improved contact with the reservoir and, what is more difficult to define, contact with the reservoir over extended distances – are equally important in applications other than those associated with steam recovery of heavy oils and bitumens.

At first, the extensions of the ideas to conventional reservoirs were simple. Oil fields tended to be planned like a checker board or a tiled bathroom floor with wells repeated, centred in square or other patterns. Horizontal wells were looked upon as improved conventional wells. Early analyses involved steady-state flow equations and the effect of substituting a horizontal well for a vertical one was seen as similar to increasing the effective wellbore radius from that of a vertical well to one involving the horizontal length of the new well. In simplest terms, one could substitute $L/4$ for R_w in the equations.

Problems quickly arise in using this idea, particularly, as often happens, if the horizontal length of the well is larger than that of the drainage pattern. One cannot place a well that is 1200 m long into a 16-ha (40-acre) square that has sides 400 m long. Obviously, the pattern shapes have to be changed and they become long and often quite narrow. The reader is asked to look at Figures 7.17 and 7.31, maps showing the location of horizontal wells in two modern heavy oil projects, to see how far we have wandered from the checker board design. In these applications, the wells drain areas somewhat longer than their length but only about one-tenth as wide. These are not simple, high-capacity replacements for vertical wells. Each horizontal well provides the capability of a row of many closely spaced conventional wells. Long horizontal wells such as these do not just have improved contact with the reservoir, but stretch *into* the reservoir to drain oil from regions remote from the well head.

The most important Canadian applications of horizontal wells lie in areas where gas and/or water coning is the major problem.

In some of these applications, even with horizontal wells, it is not economic to operate below the critical coning rate and, as a result, free gas and/or water are produced with the oil. The production of heavy oil is an important example. In most cases, the oil is produced by displacement by encroaching water, often from a lower aquifer. Some of the oil is produced as the water moves through the reservoir to appear at the well and more – usually much more – is produced later by the removal of oil from the swept region by further water displacement (waterflooding). The length of the horizontal well allows a much greater volume of the reservoir to be involved than with vertical wells. Thus, for a particular limiting economic WOR, there is a much larger production of oil. In round numbers, ten times as much oil can be produced by a well that drains ten times as much reservoir, but only costs twice as much.

With less viscous oils in suitable reservoirs, operation below the critical rate for coning becomes possible. For example, in the Rospo Mare reservoir in Italy, the permeability is high enough to allow heavy oil to be produced at practical rates without water production, even though the oil lies above a highly active aquifer.

Production of bitumen and heavy oil in the SAGD process referred to above can be accomplished at economic rates without the bypass of steam, a fact that surprised many, but is now established. Oil is removed at rates in the order of 0.15 m^3/d per metre of horizontal well without the production of live steam. With vertical production wells, steamflooding processes inevitably result in steam production.

The application of horizontal wells to fractured reservoirs, either those with natural fractures or, in some cases, with artificial fractures, is an important application. In some cases, fractures provide a great improvement in performance. The now-classical case of this, and until now the largest application of horizontal wells, is in the Austin Chalk reservoirs of Texas. For example, one company, Oryx Energy Co., has drilled more than 700 horizontal wells in this area. Horizontal wells provide a means of connecting with, and draining, vertical fractures in the reservoir; and these fractures act as gathering conduits for the flow of oil.

In other reservoirs, particularly those where coning is a problem and where rates above the critical must be used for economic reasons, vertical fractures can be undesirable because they provide passages for the premature intrusion of excessive water or gas into the well. Here, fractures are to be avoided. A Canadian example of this is in the carbonate beds of S.E. Saskatchewan where operators drilled their first horizontal wells with the intention of intersecting as many fractures as possible. They have now found it better to drill horizontal wells parallel to rather than normal to the fracture trend to avoid intersection.

The technology of horizontal wells has been, and continues to be, a fascinating story. These wells provide a means for unlocking more of our petroleum resources. It is, for example, particularly interesting for this author to read that hundreds of billions of barrels of Canada's bitumen resources may be exploitable by the horizontal well approach.

It has taken the author many hours, often borrowed from other activities, to write this monograph. He is aware of some, but perhaps not all, of the book's limitations but, nevertheless, hopes it will prove to be interesting, useful and stimulating to his colleagues in the industry.

He would like to acknowledge the support that was given by the many companies in, and associated with, the petroleum industry, and by the Petroleum Society of CIM, when they established the Endowed Chair of Petroleum Engineering at the University of Calgary. This allowed the University of Calgary to provide him with a "Chair" in which to write it. He is particularly grateful to Dr. Robert Heidemann for his support which he gave him as Head of the Department of Chemical and Petroleum Engineering. The book has also benefited greatly from the support, suggestions and comments that have been given by the author's students, associates and friends and he is grateful.

The author began to accumulate the material for the book in 1987, when he toured a number of SPE sections as a lecturer on the subject. Further additions were made as he prepared the several editions of notes for the short courses he has offered on the subject through The University of Calgary's Continuing Education Department, the CIM and others. For the past three years he has presented a graduate course on the subject at the Department of Chemical and Petroleum Engineering at The University of Calgary. These courses have been attended by many engineers from industry as well as by graduate students and many useful comments and additions have come from their participation.

The author wishes to thank the Petroleum Society of CIM for inviting him to prepare this monograph and for publishing it. He is also grateful to Dr. Dale Wong and the members of the Society's review committee, whose names are listed elsewhere, for their valuable suggestions for improvements and additions.

The book would not have been possible without the dedication and support of Patricia Stuart who has typed the whole manuscript, not once, but many times as it has been modified and as it has grown. She is a real professional and friend, and the author is very grateful.

Finally, the author would like to thank his dear wife, Joyce, for the patience, understanding, support and tolerance she has so willingly given during the preparation of the book. It is probably only she who realizes what a time-consuming, single-minded effort was required to complete the task.

Roger M. Butler, Calgary 1994.

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RMB

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Work began on the *Horizontal Wells for the Recovery of Oil, Gas and Bitumen* monograph more than two years ago. The "seed" idea for the monograph was Soheil Asgarpour's, the then-chairman of the *Journal of Canadian Petroleum Technology* Editorial Review Board, and a small but hardy group of pioneers, all members of the board. Having no predecessors by which we could pattern our work, our first task was to set the foundation principles upon which the final product would be constructed. We decided to use a single author. We wanted the content to be focused on Canada, but to be world-class in scope. We wanted the monograph to contain the most current technology available with an emphasis on application. We wanted the monograph to cover a broad range of topics on horizontal well technology so that it would become a "must have" addition to the library of practitioners of this technology.

Our choice of author was Roger Butler. Dr. Butler has been instrumental in elucidating many of the important aspects of horizontal wells and actively advocated their use long before it became as commonplace to use them as it is now. His final work contains a rich variety of theoretical development as well as numerous illustrative examples and field cases. Almost all aspects of the technology are covered in detail with the possible exception of the emerging science of horizontal well simulation; perhaps the subject of a future monograph. We believe the monograph will eventually become a classic in the petroleum engineering literature but, of course, we leave this to the judgment of history.

We are grateful for the efforts of Soheil Asgarpour, Tom Hamp and John Wansleeben. Each made an important executive contribution at critical stages. Soheil launched the effort and worked tirelessly in the early days of the project. Tom was instrumental in helping to provide a strong structural framework for the monograph and greatly aided the scheduling work. John has provided the essential "final stretch" effort to completion. Our "pioneers", without whose early efforts the monograph would not have been produced, were Gokhan Coskuner, Sunil Kokal and Tee Ong. Catherine Buchanan of The Petroleum Society of CIM office made significant contributions to the administrative aspects of the monograph. I am personally grateful for the collaboration with Petroleum Society Calgary Section representatives Eric Denbina, Bob Etcheverry and Roberto Aguilera. In particular, my collaboration with Roberto was especially helpful.

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Ion Adamache - (Ch.'s 5 and 7)
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Roberto Aguilera - (Ch.'s 6 and 9)
Doug Gust - (Ch.'s 2 and 3)
Ken Porter - (Ch.'s 2, 4 and 10)
Tee Ong - (Ch.'s 1 and 11)

On behalf of the Business and Scientific Committees,

Dale Wong
Chairman

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CHAPTER ONE

HORIZONTAL WELLS FOR THE RECOVERY OF PETROLEUM

The drilling and utilization of horizontal wells is one of the most active and exciting areas of development in petroleum production technology. This monograph describes how horizontal wells are drilled and completed, how they perform compared to conventional, near-vertical wells, and the results obtained in various field applications. Most of the current areas of interest and activity are reviewed, including the application of horizontal wells to the production of gas, conventional crude oils, heavy oils and bitumen. The improved economy possible with the use of horizontal wells for producing heavy oils and bitumens is of particular importance to Canada because of the vast size of those resources in this country and because of the difficulties in obtaining high recoveries and economic production by other means.

This chapter introduces the possible advantages of using horizontal wells for petroleum production from both conventional and heavy oil reservoirs. It discusses the methods used to drill horizontal wells and their historical development, reviews costs of horizontal wells and summarizes recent activity in this area. Each of these topics is covered in more detail and with expanded scope in later chapters.

Improved Reservoir Contact and Reduced Distance for Oil Flow

Traditionally, the discovery and production of petroleum has involved drilling downwards from the surface to the petroleum reservoir and then, if a suitable petroleum deposit is penetrated, completing the well so that it is open to the reservoir. The wellbore is maintained below the reservoir pressure and petroleum fluids flow to it. A significant problem with this process is the restriction to fluid flow encountered by the reservoir fluids as they flow radially to the production well. As the fluids approach the well, the area for flow decreases and the fluid velocity increases; as a result the pressure gradient rises rapidly. Most of the available pressure drop is dissipated in the near-wellbore region. By extending the wellbore using horizontal drilling, the length of well available for fluid entry is increased and, for a given flow, the pressure drop is decreased. This allows the drainage rate to be higher. The use of horizontal wells is an alternative to other means for improving the contact with the reservoir. These other means include drilling additional wells to provide more sinks for fluid flow and improving the effective permeability near the wellbore by creating artificial fractures and/or by acid stimulation treatments and the like. Operators are discovering that the use of horizontal wells is frequently more economic than these alternative methods for increasing reservoir contact.

Often one horizontal well can replace several vertical wells and, as a result, can be economic even though a single horizontal well may cost more to drill and complete than a vertical well. In some cases, horizontal wells make recovery economic in situations where conventional wells would be impractical. This is illustrated by the following simple numerical example. As will be discussed later, the productivity of a vertical well draining a cylindrical reservoir in pseudo-steady state flow is given by the equation[1]:

$$q = F_D \frac{2\pi kh(\overline{P} - P_w)}{\mu\left[\ln(R_e/R_w) - 0.75\right]} \tag{1.1}$$

where

F_D = dimensional factor - see footnote
q = production rate, L^3T^{-1}
k = permeability, L^2
h = reservoir height, L
$\overline{P}$ = average reservoir pressure, $ML^{-1}T^{-2}$
P_w = wellbore pressure, $ML^{-1}T^{-2}$
μ = fluid viscosity, $ML^{-1}T^{-1}$
R_e = reservoir radius, L
R_w = wellbore radius, L

This equation may be rearranged to yield a dimensionless productivity index, J^* as follows:

$$J^* = \frac{q\mu}{F_D kh(\overline{P} - P_w)} = \frac{2\pi}{\ln(R_e/R_w) - 0.75} \tag{1.2}$$

This index depends upon the radius of the wellbore R_w . It is shown in Chapter 5 that, for a large thin reservoir, a horizontal well of length L gives a performance equal to that of a ver-

1 If F_D = 1 then this equation is written in a dimensionally consistent form. If "field units" are employed, the following factors should be used:

F_D = 0.001127 for q B/D; k md; h ft; P psi; μ cp
or F_D = 86.4 for q m³/D; k μm²; h m; P MPa; μ mPa.s or cp.
N.B. 1000 md = 987 μm².

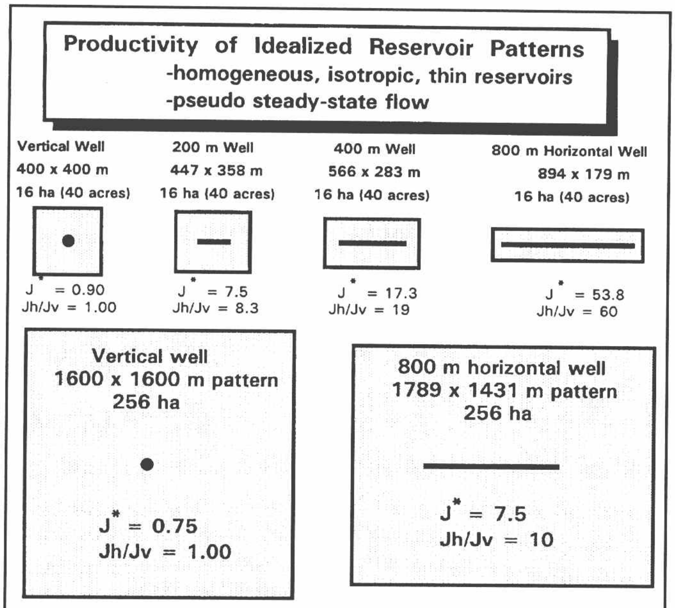


FIGURE 1.1

tical wellbore having a radius equal to $L/4$. This approximation only applies when the length of the wellbore is much smaller than the diameter of the reservoir. Increasing the value of R_w in equation (1.2) to a value $L/4$ has the effect of increasing the dimensionless productivity J^*. A numerical example of this effect is given by the calculation in the following table:

TABLE 1.1 Dimensionless productivity for a central vertical well draining a thin reservoir of radius 903 m (256 ha) or approximately 1 section

R_w, m	J^*	J/J_v‡
0.1	0.75	1
50	2.93	3.9

‡ This ratio is a normalized dimensionless productivity.

Thus, in this example using a horizontal well 200 m long with an effective radius of 50 m in place of a conventional well with a radius of 0.1 m increases productivity by a factor of 3.9. The calculation in Table 1.1 describes the drainage of a reservoir having a radius of 903 m or a drained area of about 256 ha. In this example, the horizontal well decreases the flow restriction around the well; over most of the reservoir, the flow is still essentially radial towards the well.

Horizontal wells, because they can extend for long distances through the reservoir, can also provide conduits for the horizontal transport of the reservoir fluids. This effect becomes more important if the length or, more precisely the square of the length, of the horizontal well is large compared to the drainage area A. Thus, with relatively long horizontal wells, fluid does not have to move as far through the reservoir because of the horizontal transport taking place within the production well. In addition, with small A/L^2, the flow over much of the reservoir pattern is linear rather than radial.

For small values of A/L^2, the optimum shape of a drainage pattern is elongated; in the simplest case, a rectangle. Later in Chapter 5, methods are shown for calculating the optimum shape of this rectangle and the following equation is given for estimating the corresponding dimensionless productivity index.

$$J^* = \frac{12}{\ln(1 + A/L^2)} \tag{1.3}$$

The lower part of Figure 1.1 shows calculations for an 800-m horizontal well draining the same area as in the example of Table 1.1. In this case, the optimum pattern is a rectangle 1789 m by 1431 m and the productivity is about ten times that of the vertical well.

The upper part of the figure shows the results of similar calculations for a drainage area of 16 ha. In this case, the productivity of the vertical well is only about 20% greater than that of the vertical well draining the much larger area discussed previously; however, the horizontal well shows much greater productivity enhancement as the shape of the drainage area becomes more elongated. The 16-ha pattern for the 800-m well is 894 m long by only 179 m wide, but the productivity index is sixty times higher than that of the vertical well. The effect is much greater than for larger drainage areas. The reason is apparent from the figure. The 800-m horizontal well in the 16-ha pattern has an improved productivity, not only because of its better contact with the reservoir, but also because the reservoir fluid does not have to move as far to reach the well.

In each of the examples shown in the figure, the horizontal well provides increased productivity, but the effect is much larger when the well is constrained to drain a smaller area. This is because the horizontal well allows drainage without the need for the reservoir fluids to move as far through the reservoir; for the same pressure drawdown, there is a larger pressure gradient in most of the reservoir and a higher productivity.

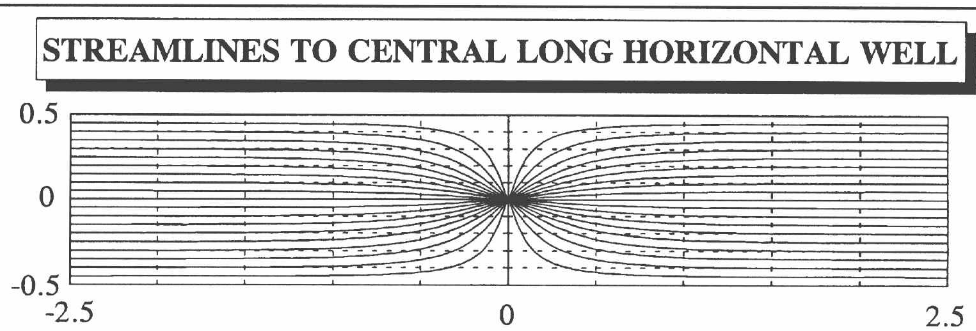


FIGURE 1.2

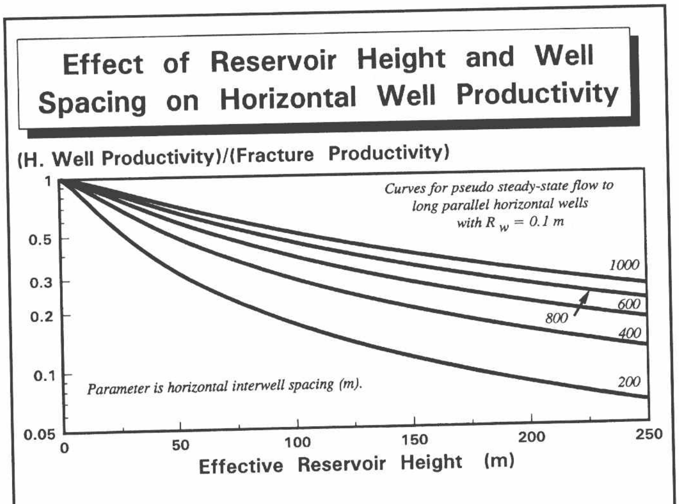


FIGURE 1.3

Effect of Reservoir Thickness

In the examples described in the previous section, it was assumed the reservoir was "thin" and the performance of a horizontal well would be the same as that of an infinite conductivity fracture having the full height of the reservoir and a length equal to that of the horizontal well. In many cases, this is a good approximation. However, for thicker reservoirs, the performance of the horizontal well is reduced because of the need for the flow to converge vertically to the wellbore. Figure 1.2 shows the calculated position of streamlines converging to a horizontal well located centrally in the reservoir. The theory on which this figure is based is discussed in Chapter 5 and it is shown how quantitative allowances for the effect can be made. The extra pressure drop needed to achieve the convergent flow reduces the productivity of horizontal wells in thicker reservoirs. The effect is shown in Figure 1.3 where the ratio of the productivity of a long horizontal well to that of a vertical fracture of the same length in the same reservoir is plotted against the reservoir height. These curves are for a well with a radius of 0.1 metre in a reservoir having the same vertical as horizontal permeability. If the permeabilities are not equal, the actual reservoir height should be multiplied by the square root of the permeability ratio, $\sqrt{k_h/k_v}$, to give the effective reservoir height. Thus, vertical permeability can be a very significant factor, particularly in thick reservoirs.

Application in Reservoirs with Bottom Water or with a Gas Cap

In many cases, the most important factor limiting the production of oil from a reservoir is the tendency for water from an underlying aquifer, or gas from a gas cap, to be drawn vertically to the production well. Horizontal wells can have substantial advantages in such reservoirs. The conventional way of reducing the effect of coning is to complete the vertical well over a limited vertical distance to maximize the standoff from the water or gas cap, as the case may be. In these circumstances, the contact of the vertical well with the reservoir is reduced even further than it would be for a full height completion. The effect of reservoir height on the relative performance of a horizontal well is much smaller.

Because of its extended contact with the reservoir, a horizontal well usually has less pressure drawdown for a given production rate than does a vertical well. This reduced drawdown lessens the tendency for the coning of water or gas with the produced oil. Thus, for example, horizontal wells may be operated at the same rate as conventional wells but with less – sometimes much less – coning, i.e., with better water-oil ratios or gas-oil ratios or both. In some cases, production without coning may be economic using horizontal wells, where it would be prohibitively slow with conventional wells. In situations where the initial rate for production without free gas coning would be impractical with vertical wells, it may be possible with horizontal wells to achieve economic production by gravity drainage with only a small rate of gas injection to maintain gas cap pressure.

Even if operation below the critical rate for coning is impractical because of economics, there can still be a large advantage for horizontal wells. This situation is common when viscous, conventional heavy oils such as those in Saskatchewan are produced from above a water layer. Here, the high oil viscosity and the low difference in density

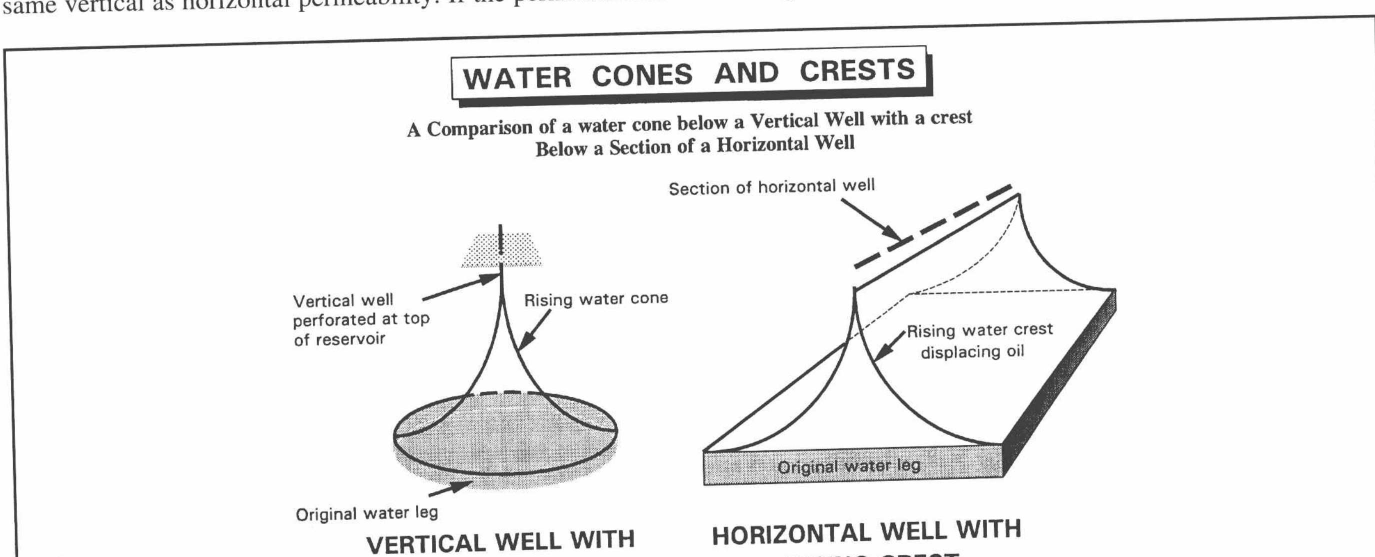


FIGURE 1.4

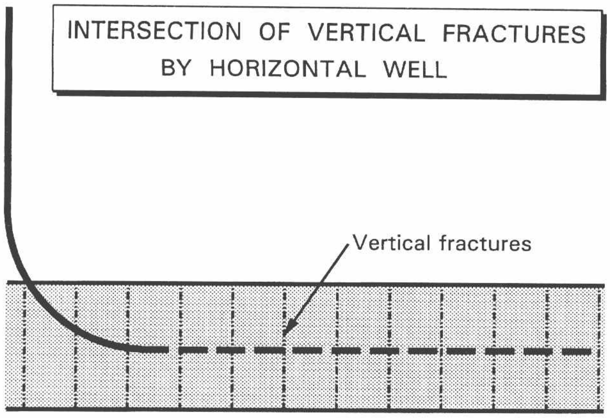


FIGURE 1.5

between the oil and water makes coning, or more correctly fingering, occur even at very low production rates. In these cases, the volume of oil that is produced is approximately proportional to the volume swept by the water finger. As is shown in Figure 1.4, horizontal wells have an advantage over vertical wells here because the finger (really a "crest" shaped liked the roof of a house along the length of the horizontal well) has a much larger volume and this larger crest displaces a much larger volume of oil.

This application is being developed enthusiastically, particularly in Canada. For instance, it has been reported that in Saskatchewan heavy oil fields horizontal wells can produce about ten times the volume of oil that can be produced by conventional ones. This extra production offsets the horizontal wells' approximately double cost. In some reservoirs in Saskatchewan, it is economic to produce oil with horizontal wells but not with conventional ones.

Intersection of Vertical Fractures

Many reservoirs consist of a fine, low-permeability matrix penetrated by natural, approximately parallel vertical fractures. Connection of a production well with these fractures is important if high productivity is to be obtained. When the fractures are vertical or nearly vertical, their intersection by vertical wells is difficult. On the other hand, the length of a horizontal well, particularly if it is drilled at right angles to the planes of the fractures, can provide contact with multiple fractures and a greatly improved productivity. This is shown diagrammatically in Figure 1.5. In this situation, horizontal wells have produced excellent results. The astonishing development of naturally fractured fields in the Austin Chalk formation of Texas and in the Bakken shales of North Dakota are described later in Chapter 9. A related application is to karstic reservoirs which contain interconnecting solution cavities and passages. Production from such reservoirs is dependent upon intersecting these flow systems. The chances of doing this are much greater with a long horizontal wellbore.

In reservoirs where fractures do not occur naturally, it is sometimes possible to create vertical artificial fractures. Preferably, these should extend at right angles to the well,

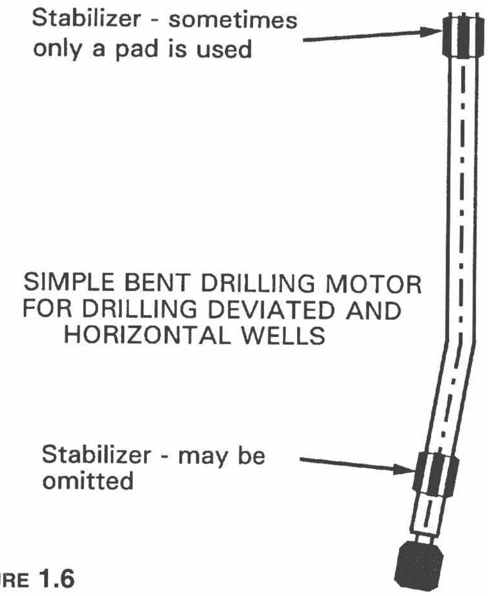


FIGURE 1.6

although in some cases – for example, with horizontal wells drilled like spokes of a wheel from an offshore platform – this may not be practical. Success has been obtained in making multiple fractures along the length of a horizontal well so that each fracture contributes to the well's productivity. For example, a well with five artificial, equally spaced fractures originating from it can have an initial productivity approximately five times that of a vertical well with a single artificial fracture in the same reservoir. An example of this type is discussed in Chapter 10.

Advantages of Horizontal Wells in Offshore Applications

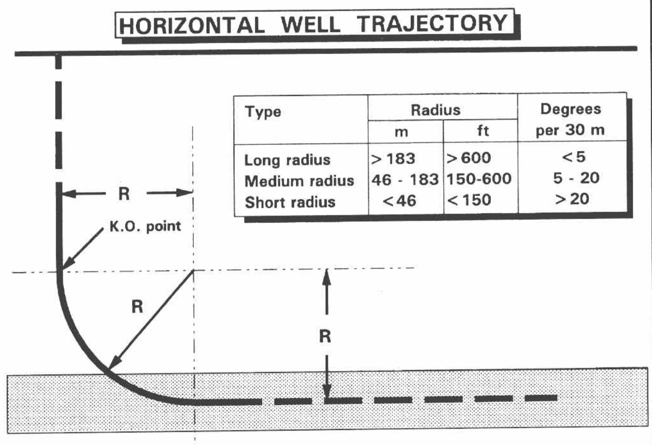
Many horizontal wells have been drilled from offshore platforms. Such wells offer savings in platform costs in addition to the advantages found onshore. For example, one operator states that the cost of his North Sea platforms is approximately \$6 million per well slot, (Andersen, Hansen and Fjeldgaard 1988)[2] Using horizontal wells, the same number of well slots on a platform can produce more product since each horizontal well is more productive than each conventional well. Furthermore, since offshore wells are normally highly deviated in any case the extra cost for horizontal drilling can be relatively small.

Commercial offshore horizontal well projects in various areas including the Adriatic, the North Sea and the Java Seas are described later.

Heavy Oil Applications

Probably the most prospective area for using horizontal wells lies in the field of heavy oil recovery, particularly thermal recovery using steam. There are enormous opportunities here. For example, the bitumen deposits in Canada, which are impossible to recover economically by

[2] References are documented in Chapter 14.



Type	Radius		Degrees per 30 m
	m	ft	
Long radius	> 183	> 600	< 5
Medium radius	46 - 183	150-600	5 - 20
Short radius	< 46	< 150	> 20

FIGURE 1.7

conventional methods, have a volume of oil in place approximately equal to that of all the known conventional crude oil in the world. One approach used to recover these resources is open pit mining. However, this is limited to the small fraction of the Athabasca reservoir that is close to the surface and the approach involves handling vast quantities of material. In situ thermal recovery is more generally applicable, cheaper and less damaging environmentally.

Thermal recovery normally requires close well spacings. Typical projects have a spacing of 1 to 2 hectares (2.5 to 5 acres) per well and, in many cases, these are later infilled to improve recovery. Steamflood projects in California with spacings as low as 0.25 ha (5/8 acre) are being operated. In such circumstances, a single horizontal well can replace a row of as many as ten or more conventional wells. This may become one of the most important applications of horizontal wells. The successful operations of field pilots in Cold Lake, the Lloydminster area and in Athabasca using horizontal wells and steam-assisted gravity drainage (SAGD) are discussed later in this monograph. A particularly important feature of the use of horizontal wells for steam recovery is that it is possible to operate and obtain high recoveries with little steam production, i.e., with little steam bypassing by cresting. With horizontal wells, it is possible to produce economically below the critical rate for steam bypass; with vertical wells, steamflooding is impractical without the bypass of steam except on very close spacings.

Drilling Horizontal Holes

Typically horizontal wells are drilled using downhole, bent mud motors. The principle is shown in the exaggerated and simplified diagram in Figure 1.6. Usually, the mud motor employs a helical rotor that rotates within a hollow, helical, rubber-lined chamber. It is a Moineau pump operated as a motor by forcing the drilling fluid through it. Mud forced into the motor causes the shaft to rotate, turning the drill. The motor has one or two bends in it that cause the bit to sit at an angle to the main drill string. As a result, when the rotating bit is thrust into the ground, it tends to drill a curve. The degree of curvature depends upon the geometry of the motor. Frequently two types of motor are used, one to "build angle" and one to "hold angle" in the horizontal section. If the maximum curvature required is not very great, it is possible to use the same motor for both purposes.

Motors with only a small bend in their length can be operated in both the sliding mode and the rotating mode. In the sliding mode, the drill string is not rotated and the motor body slides forwards, making a curve determined by its geometry. The direction in which this curve leads can be controlled by adjusting the angular orientation of the drill string. If the bend in the drill assembly is not too great, then the drill string can be rotated as well, making the drill proceed in a close spiral that is almost a straight line. However, in this mode in a horizontal hole there is a tendency for gravity to make the tool point downwards and the hole to droop. This can be overcome by alternating sliding and rotating operation. A motor that can be operated in the rotating mode is known as a steerable motor. Angle-hold motors are typically steerable.

The drilling of most horizontal wells can be classified into long-radius, medium-radius, and short-radius techniques. These are illustrated in Figure 1.7. In addition to the three most common horizontal drilling techniques listed above, there are two other, less used classifications: ultrashort radius, in which R can be as small as 30 cm; and holes drilled from underground mines, which can be horizontal without requiring any curvature. These are discussed together with the more common methods in Chapter 2.

Long-radius wells are drilled with basically the same equipment used for the deviated drilling of conventional wells. One successful technique uses a motor similar to that shown in Figure 1.6 without a lower stabilizer and with a simple pad at the top. The main disadvantage of the long-radius technique is the necessity to drill farther to reach the given target. If the initial hole is to be vertical, the wellhead must be located a distance from the horizontal well at least equal to the radius of curvature. This distance restriction can be overcome by starting to drill the hole at an angle to the vertical. Drilling rigs that allow this are termed "slant rigs".

Today, most horizontal wells are drilled using medium-radius techniques. Specialized motors containing double bends have been developed. Many of these motors can be adjusted to give different curvatures. Horizontal drilling is discussed in more detail in the next chapter.

Improvements in Drilling Technology

Horizontal wells are of great interest to the petroleum industry today because they provide an attractive means for improving both production rate and recovery efficiency. They can be drilled as new wells or horizontal sidetracks, drilled to revitalize the performance of existing vertical wells. Both approaches are being used. The past few years have seen great improvements in drilling technology. Developments such as the use of bent, downhole drilling motors, top-drive drill rigs, and MWD (Measurement While Drilling), together with steerable drill systems have greatly reduced costs. Recent horizontal wells have cost no more per metre of well drilled than comparable conventional wells. It is frequently possible to locate horizontal wells within ± 2 metres of the preplanned depth. Wells have been drilled with horizontal sections more than a mile in length open to the reservoir. They have been drilled as shallow as 15 m (15 ft) (for pipeline crossing of rivers) and as deep as 3350 m (11,000 ft). Great advances have also been made in methods for drilling short-radius drainholes from existing vertical wells.

The construction and placing of horizontal wells has become routine. Usually it is no longer speculative as to whether horizontal wells can be drilled. In most cases now, the choice is not whether one can drill horizontally, but whether one should.

Great advances in the technology of drilling and locating horizontal wells continue to be made. Today much attention is being paid to the problems of re-entering existing vertical wells using smaller diameter, medium-radius and short-radius equipment. These improvements will allow a much larger proportion of existing conventional wells to have their lives extended by re-completion with long, horizontal drainholes. The provision of MWD tools that will operate in smaller diameter holes is a particularly active area. There are new developments, too, in logging tools. Tools are now available that can be operated while drilling to provide information about the reservoir being encountered. Locating the logging sensors closer to the drill bit to allow a more timely evaluation of the bit position and of the rock being penetrated is another area of active development.

Horizontal Well Development – Major Milestones

Petroleum was known in most of the ancient world and its earliest production was achieved through the use of dug excavations. In some cases asphalt deposits were simply mined. In others, a shaft was dug and liquid petroleum was collected as it seeped into the hole. Early hand-dug oil wells included ones 600 to 900 ft deep in Japan in about 600 A.D. and wells in Burma in 1600 A.D. The first well in the Pechelbronn oil field in Alsace, France was dug in 1745. By the end of the 18th century, wells as deep as 1115 ft had been dug in the field (Brantly, 1971).

The drilling of wells as opposed to the digging of wells appears to have had its origins in China, where drilling, using spring-pole techniques, is reported to have been carried out more than 1000 years before it was rediscovered at the end of the 18th century in Europe and America (Stockil, 1977).

James Miller Williams, often called the father of the North American petroleum industry, *dug* the first productive well in North America. Working with Charles Nelson Tripp, Williams dug a 49-ft-deep well in Enniskillen township near Sarnia in 1857 (Purdy, 1958) for the purpose of producing oil and refining it. He is credited with "being the first to *dig* for oil, get it in ample commercial quantities and refine it for illuminating oil and lubricants". Two years later, "Colonel" Edwin L. Drake, using a cable tool rig originally developed to *drill* for water, completed a well in Titusville, Pennsylvania on the other side of Lake Erie. On August 28, 1859, that well started producing, and the North American oil industry began its rapid growth as oil production in both Ontario and Pennsylvania boomed.

For the most part, the development of the oil industry has been through drilling although, in a few places, development by mining has continued. Well-known oil mining operations include those at Pechelbronn in France and Wietze in Germany (Rise 1932). In both operations, long tunnels were dug in relatively shallow oil reservoirs and the oil collected as it seeped through the tunnel walls. From these tunnels, or galleries, drainage holes were drilled into the producing strata to enhance the production. These drainage holes were often approximately horizontal and in one sense they can be looked upon as the predecessors to our modern, drilled horizontal wells. In 1965, it was reported that the mines at Wietze had produced 8 x 10^5 m^3 (5 x 10^6 B) of oil in the previous thirty-two years (average 68 m^3/d or 428 B/d) and those in Pechelbronn, 1 x 10^6 m^3 (6.25 x 10^6 B); the Pechelbronn production was 84 m^3/d (530 B/d) in 1954 (Eastman 1954).

Other significant oil mining developments include those in the Yaregskoye field (Yarega) in Russia. This heavy oil mine, which started in 1939, employs long horizontal wells extending radially from underground drilling chambers with separate, inclined steam injection wells drilled from higher chambers. Initial production was by non-thermal methods; steam injection began in 1968 (Bernshtein et al., 1974).

An early horizontal well 290 m (953 ft) long was drilled by Leo Ranney (Ranney, 1939) into an outcrop of reservoir sand in Morgan County, Ohio. In 1941, Ranney drilled holes from the bottom of a shaft within a depleted sandstone reservoir near McConnelsville, Ohio. In all, he drilled six horizontal wells with a total length of more than 2.4 km (Eastman, 1954). In 1942, Ranney developed a similar project involving drilling horizontal holes from a shaft in the Franklin heavy oil field in Venango County, Pennsylvania. Initially he drilled two holes, one 687 m (2255 ft) and the other 711 m (2334 ft) long. Later he drilled four 305 m (1000 ft) and four 183 m (600 ft) horizontal holes. While these produced much more oil than existing vertical wells, the reservoir was of relatively poor quantity and only 3 m^3/d (20 B/d) of oil were produced in total. A considerable improvement was made by applying a vacuum to the wells. In each of these projects, the wells were stimulated by shooting with gelatin dynamite. In the original two wells, 4808 kg (10,600 lb) of explosive were loaded into the holes, starting 122 m (400 ft) from the shaft wall, and detonated.

Another starting point for the development of horizontal drilling was the drilling of horizontal drainholes from vertical wells. Much of the early work in this area was concerned with developing flexible and articulated drill strings. Methods based on the work of Zublin, in which jointed rotary drill strings were used inside a flexible, curved drill guide, form the basis of the method used extensively by the Eastman and later, the Eastman Christensen companies. This is discussed in Chapter 2. Using these methods, one or more horizontal drainholes several hundred feet in length could be drilled from the side of existing wells or specially drilled vertical wells. The objective was increased production and/or reduced water or gas coning.

Another, and perhaps more influential, technology from which the drilling of long horizontal wells has evolved is that developed for deviated drilling, particularly "long reach" drilling from offshore platforms. The high cost of drilling platforms makes the ability to drill very long, highly deviated wells particularly valuable, and much of the equipment used for drilling long-radius, and later medium-radius, horizontal wells derived from this activity – in particular, the use of mud motors with bent subassemblies and later, bent mud motors. MWD techniques and top-drive drilling rigs have contributed to the ability to drill long, accurately located, horizontal wells.

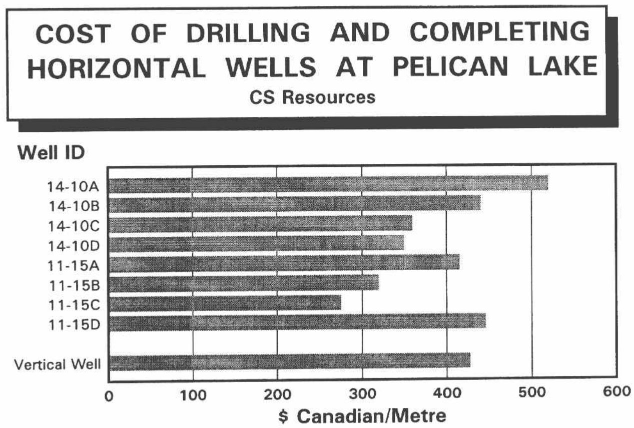


FIGURE 1.8

TABLE 1.2 Average horizontal hole drilled in Austin Chalk (Source: J. Freedman 1991)

Year	Horizontal Length, m (ft)	Days to Drill
1989	760 (2500)	24
1990	1100 (3600)	22
1991	1370 (4500)	16

Cost of Horizontal Wells

The costs of early horizontal wells were much higher than those of comparable vertical wells drilled in the same reservoir. In any new field of technology, the costs of early prototypes are much higher than those for developed operations. Reasons for the high cost of prototype horizontal wells include the cost of special precautions involved in experimental projects, the rig down-time required for periodic hole location (as contrasted to MWD) and the use of non-optimum equipment and methods.

It has been found by companies drilling horizontal wells that costs decrease as experience is gained. For example, Standard Alaska Production Co. (Wilkinson et al. 1988) found that the costs per metre of well in their Prudhoe Bay projects[3] decreased from $1516 US/m ($462/ft) to $925 US/m ($282/ft) for horizontal wells as compared to $764 US/m ($233/ft) for a conventional well. Several companies have found the cost of long horizontal wells is less than double the cost of vertical wells and, in some cases, such as wells drilled from offshore platforms where conventional wells are highly deviated, the cost almost approaches equality. Overall, for preliminary estimates, it is reasonable to assume that, with experience, the cost of drilling a horizontal well will be approximately the same per foot drilled as for a vertical well. Allowance must be made for completion costs which may be considerably higher for a horizontal well if elaborate techniques are required.

Table 1.2 contains data for wells in the Austin Chalk that were presented at a recent conference on horizontal wells. These data show the tremendous improvement in drilling time for horizontal wells as experience was gained.

Coffin (1989) has described the drilling of ten horizontal wells in two Canadian projects – eight wells in the Pelican reservoir in Alberta, and two in the Winter field in Saskatchewan. These wells were completed in 1988 and they are currently operating under primary production; results are discussed in Chapter 7. This project was the first to demonstrate that long-radius horizontal wells can be drilled in Canadian on-shore reservoirs quickly, reliably and economically. The French company, Horwell, was responsible for the drilling plans. The following table compares the eight Pelican Lake horizontal wells and shows that the drilling time for these vary from seven to twelve and a half days. They each had a horizontal length of about 500 m.

TABLE 1.3 1988 Pelican Lake horizontal wells characteristics
5 metre, 3 darcies, unconsolidated sand; 14°API oil; 600-1000 mPa.s at 20°C; ϕ 0.29; reservoir depth 410 m

Well Section 81-22W3	Total Depth (m)	Total Vertical Depth (m)	Total Horiz. Displ.(m)	Horiz. Length Drilled(m)	Max.Angle of Inclin.	Days to Drill and Complete
14-10A	1017	416	728	448	93.0	12.5
14-10B	1097	413	807	519	92.7	10.5
14-10C	1087	415	785	501	93.2	8.0
14-10D	1133	418	842	500	92.0	8.5
11-15A	1115	415	827	500	92.4	9.0
11-15B	1114	417	828	500	91.7	7.0
11-15C	1142	411	853	500	96.5	7.0
11-15D	1103	413	790	504	91.5	10.5

Figure 1.8 shows that the costs of drilling and completing these wells (based on total length) was about the same per metre as a vertical well in the same area. The cost scale on this figure is in Canadian dollars per metre[4] (in 1992, $1/m was approximately equal to US$0.25/ft). Thus, the horizontal wells costs shown in Figure 1.8 range from a high of about $520/m (US$130/ft) to $280/m (US$70/ft) of total length.

Meridian Oil, an independent U.S. company, had drilled forty-three horizontal wells in N.Dakota, Montana, S.Dakota, Alabama, Oklahoma and New Mexico (Moore 1989) by 1989.

3 The total length of a horizontal well is greater than that of a vertical well. The simplest estimate is obtained by adding the vertical depth L_V to the length of the horizontal section L_H. This is the length that would be required if the well went vertically to the desired depth and there were a very sharp radius of curvature to the horizontal. In practice, the length will be somewhat longer than this because of the length of the curved section. A better estimate can be obtained by using the formula $L = L_V + L_H + (\pi/2-1)R$. In practice, the well may be longer than this if the curved section is not continuous, eg. if it is in two parts with a tangent section. For example, a horizontal well is to be placed at the bottom of a reservoir at a total depth of $L_V = 600$ m; the horizontal section is to be, $L_H = 1000$ m and the radius of curvature is to be $R = 150$ m. Thus, $L = 600 + 1000 + 0.57 \times 150 = 1685$ m. In this hypothetical example, the length of the horizontal well would be 1685/600 = 2.8 times the length of a vertical well in the same reservoir.

4 In this monograph, "$" represents Canadian dollars, usually with a value that was current at the time of the reference. United States dollars, where quoted, are designated "US $". The unit k$ represents thousands of dollars. In some cases, a year is written in brackets after the value to indicate that the value of the dollar is to be associated with that year, e.g., US $100 (1991) means that the cost or value was equivalent to the value of 100 United States dollars in 1991.

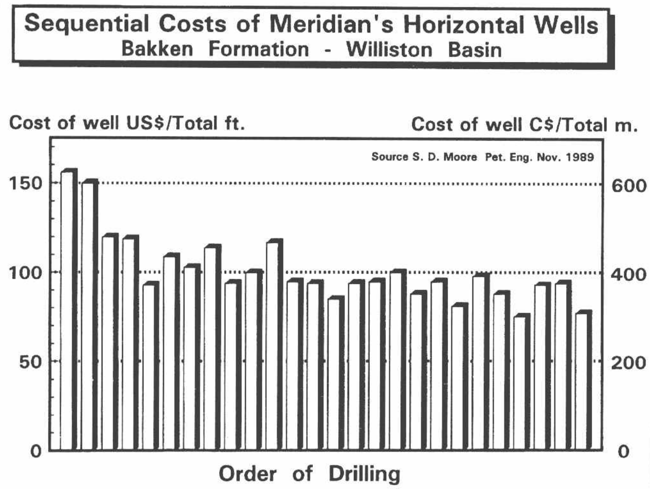


FIGURE 1.9

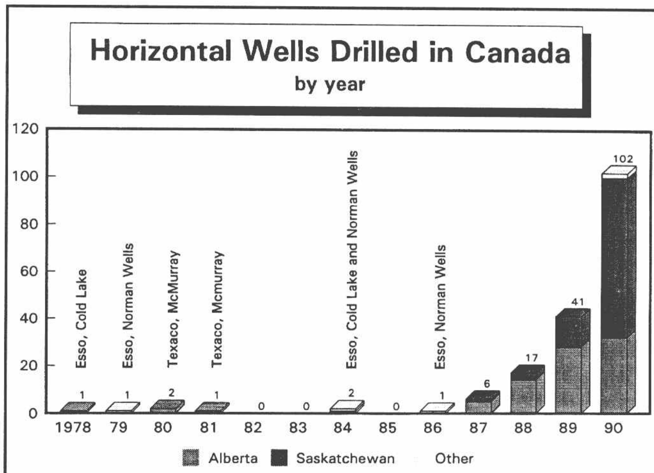


FIGURE 1.10

These are medium-radius holes, drilled with downhole motors and MWD. Typical wells were drilled with two build sections (about 14°/30m) linked together with a straight tangent.

Many of the wells are in the Bakken formation of the Williston Basin; typically, they have horizontal sections of about 580 m (1900 ft) of 139.7 mm (5.5 in) predrilled casing.

Figure 1.9 shows reported costs for the wells drilled in the Bakken formation.

As experience was gained, these costs dropped from about \$620/m \$155/ft) to \$320 to \$360/m. These are approximately in line with the costs reported by CS Resources Limited for their holes at Pelican Lake and with those reported for wells in the Pearsall field.

Horizontal Well Drilling Activity

Figure 1.10 shows the number of horizontal wells drilled per year in Canada starting with the first of the modern horizontal wells, drilled by Esso Resources Canada in its Cold Lake field in 1978. This was drilled to test Esso's steam-assisted gravity drainage process for the recovery of bitumen. This well has now produced more than 52,000 m^3 of oil and its operation is continuing; results are discussed in Chapter 11. In 1979, Esso drilled a horizontal well in its Norman Wells field and again in 1984 and 1986 (Markle 1987). In 1980 and early 1981, Texaco Canada drilled three horizontal wells at their pilot in the Athabasca tar sands near Ft. McMurray and tested these for steamflooding (Pugh 1982). In 1984, in addition to its well at Norman Wells, Esso drilled a second horizontal well at Cold Lake to test the SAGD process further; this had a length of 1000 m (MacDonald 1987). In 1986 at Norman Wells, Esso completed the longest horizontal well drilled to that time. It had a horizontal length of 1223 m (4012 ft) (Markle 1987).

Starting in 1987, the number of horizontal wells drilled per year in Canada increased rapidly. Many of these were in Saskatchewan where it was found that horizontal wells can produce Lloydminster-type, mobile heavy oil more economically than conventional wells. Higher rates were obtained and it was found that higher cumulative production was possible before watering out of the wells made them uneconomic. Although most of the Saskatchewan horizontal wells in heavy oil reservoirs have been for non-thermal recovery, the first horizontal well drilled in Saskatchewan that was completed by Sceptre Resources was used to test their version of steam-assisted gravity drainage. This project is discussed in Chapter 11. It continues to be very successful with more than 159,000 m^3 (1 million barrels) of oil produced from the first well.

Most of the Saskatchewan heavy oil projects employing horizontal wells have been non-thermal and exciting results have been obtained. CS Resources Limited, Saskatchewan Oil and Gas Corporation (Saskoil), Gulf Canada Resources Limited, Murphy Oil Company and Morgan Hydrocarbons Inc. have been particularly active in this area. There has also been considerable activity in producing lighter crude oils in S.E. Saskatchewan. By the end of 1992, the number of horizontal wells in Saskatchewan was about 3% of the total number of wells in the province while their production volume was about 17% of the total. This 17% was almost equally divided between heavy oil and light/medium oil (Sask. Energy and Mines 1993).

In Alberta, there has also been considerable horizontal well activity with emphasis in several different areas. Heavy oil production has been the focus of activity by Gulf Canada Resources Limited and CS Resources Limited in the Pelican Lake field mentioned earlier, and by Renaissance Energy Ltd., AEC Oil and Gas Company, Amoco Canada Petroleum Limited and others in the Suffield field. In the carbonate reefs of the Rainbow area, Canterra (now Husky), Mobil and Esso have successfully reduced gas coning in those light hydrocarbon, vertical floods through the use of horizontal wells (Adamache et al. 1990).

The first modern long horizontal wells drilled outside of Canada were drilled by Elf Aquitaine and the Institut Français du Pétrole (IFP) between 1980 and 1982. These are described in the Table 1.4.

The third of these wells was drilled in the large (159 x 10^6 m^3, 1 billion barrels) Rospo Mare reservoir in the Adriatic Sea. Horizontal wells proved to be ideal for producing the viscous (300 mPa.s) heavy oil contained in this karstic reservoir above an active aquifer. The advantages of horizontal wells stem from the lower pressure drawdown resulting from their length (this allows production without water coning) and from their success in penetrating more of the fractures and solution

TABLE 1.4 The first three IFP/Elf Aquitaine horizontal wells (Bosio and Reiss 1988; see also Reiss 1987)

Year	Field	Length within Reservoir (m)	Drilling Time Days	Designation
1980	Upper Lacq SW France	275	44	La 90
1981	Upper Lacq SW France	472	42	Lacq 91
1982	Rospo Mare Adriatic Sea, Italy	603	84	RSM 6 D

cavities which characterize reservoir structures of this type. Conventional vertical wells, because of their reduced length of penetration, are much less likely to make these productive penetrations.

The largest growth in the use of horizontal wells started outside of Canada in 1989 when a horizontal well drilled by Oryx Energy Co. achieved very high production rates in the generally uneconomic Pearsall reservoir in the Austin Chalk trend in Texas. The success of horizontal wells in this area depends upon the their intersecting the vertical fractures which carry the oil. The growth of horizontal drilling in this field and in the Giddings field in Texas has been phenomenal. In 1991, 795 horizontal wells were drilled in the Austin Chalk, comprising 57% of the total number of horizontal wells that were drilled worldwide. Drilling in these areas is now decreasing. Austin Chalk production is described in Chapter 9. Figure 1.11 shows historical data on horizontal wells completed in the United States.

Another development, similar to that in the Austin Chalk, has been the drilling of the Bakken shales in North Dakota by Meridian Oil Inc. and other companies. Again, this activity depends upon the penetration of separated productive fractures by horizontal wells.

A wide variety of other successful applications for horizontal wells has been developed. The development of the Rospo Mare field mentioned earlier has continued and there are now three production platforms. In the North Sea there have been numerous horizontal well projects. Particularly interesting are those of Statoil in the Statfjord field where the C-39 well, with a record horizontal length of 2144 m (7035 ft), produced 4770 m^3/d (30,000 B/d)(Halvorsen 1991) and Norsk Hydro in the Troll field (Anon. May 14, 1990). British Petroleum Exploration Company Limited, U.K. is producing the small Cyrus field in the North Sea with a single horizontal well (Anon., Sept 5, 1988; MacDonald 1988; Clark and Cocking 1989).

In the Danish sector of the North Sea, Mærsk Olie og Gas (Mærsk) produces oil from the Danish Chalk using long horizontal wells which have been artificially fractured.

Unocal, in a pioneering project carried out between 1986 and 1988, drilled medium-radius horizontal legs from existing, high-water-cut, conventional wells in the Helder field on the Dutch continental shelf of the North Sea. These reworked wells produced oil successfully at a higher rate with a lower water-oil ratio. An improved ultimate recovery is forecast; the project is described in Chapter 7.

Another early project is that of Standard of Alaska (now BP Exploration Alaska) which has drilled long horizontal wells in the Prudhoe Bay field. As is described in Chapter 8, these have demonstrated productivities of two to four times that of conventional wells and the development work has led to several improved techniques and ideas.

In the Java Sea, about 80 km northwest offshore of Djakarta, Indonesia, lies the Bima oil field. Owned and operated by Arco Indonesia, this muddy carbonate, complex reservoir has been developed from offshore platforms by horizontal wells combined with some conventional wells (Barry, Troncoso and Sumantri 1988). With fewer wells required because of the horizontal drilling the investment requirements were significantly lower and the project is an economic success.

The West Mining Corporation of Perth (Anon., June 13,

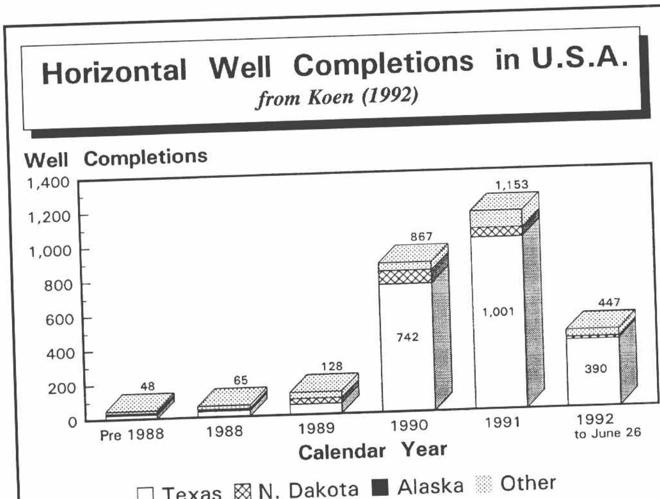


FIGURE 1.11

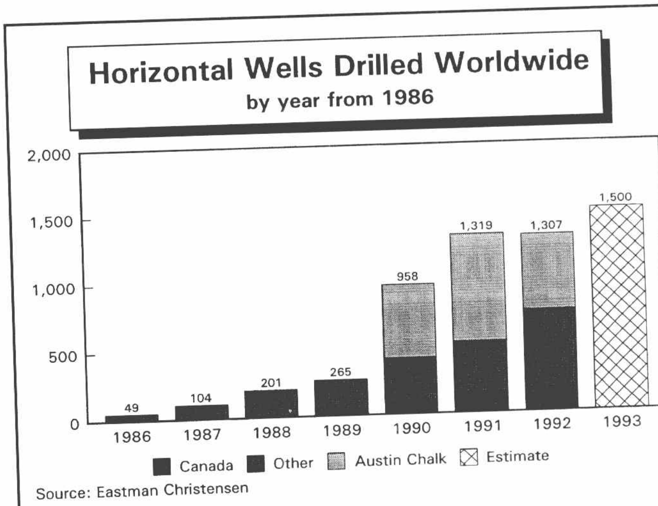


FIGURE 1.12