HORIZONTAL AND MULTILATERAL WELLS: PLANNING, TECHNOLOGY & PERFORMANCE

A FINAL PROJECT REPORT
SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR
THE DEGREE OF BACHELOR OF TECHNOLOGY
(APPLIED PETROLEUM ENGINEERING)

Submitted To:

UNIVERSITY OF PETROLEUM AND ENERGY STUDIES

Guided by:

PROF. C.K JAIN

Submitted By:

K Kaladhar Sharma (R010203037)

Debaditya Barua (R010203035)

CERTIFICATE

This is to certify that the Project Report on **"Horizontal & Multilateral Wells: Planning, Technology & Performance"** submitted to University of Petroleum & Energy Studies, Dehradun by **Debaditya Barua & K. Kaladhar Sharma** in partial fulfillment of the requirement for the award of Degree of **Bachelor of Technology** in **Applied Petroleum Engineering** (Academic Session 2003-2007) is a bonafide work carried out by them under my supervision and guidance.

This work is deemed good and satisfactory.

CKJain
08/05/07

Date: **Mr. C.K Jain**

(Senior Professor, COE, UPES)

Acknowledgement

This report bears imprints of many people.

We are thankful to ***University of Petroleum & Energy Studies*** for giving us this opportunity to carry out our major project on "**Horizontal and Multilateral Wells: Planning, Technology & Performance** ".

We would like to thank **KDMIPE-ONGC Dehradun** for permitting us to access their library. We are thankful to **Schlumberger Asia Services Ltd** who believed in our efforts and accepted our project for the Schlumberger Indian University Handshake Program (**SIUH**). We are grateful for their assistance throughout the project.

We are indebted to our guide Mr. C K Jain (Senior Professor, College of Engineering) and Mr. B.P Pandey (Dean, College of Engineering) for their invaluable and erudite guidance, keen interest and constructive suggestions, timely and generous help beyond measure at all the stages during the progress of the project work.

At last we extend our thanks to all our colleagues who motivated us through the hard times and who were a constant source of help.

K KALADHAR SHARMA

DEBADITYA BARUA.

(B-Tech Applied Petroleum Engineering)

UNIVERSITY OF PETROLEUM & ENERGY STUDIES
DEHRADUN

Abstract

This project is an endeavor to understand the latest and complex technology of horizontal and multilateral wells, starting with the planning and design aspects and finally venturing into the performance of such wells.

In order to meet the growing insecurity about the future of petroleum, it is essential to maximize the recovery of the current reserves in as economic way as possible. Here in lies the edge that horizontal and multilateral have over conventional wells. Not only they can be used for maximizing the recovery with a fewer number of wells, but also facilitate the exploitation of inaccessible, low permeability and thin reservoirs Therefore as future professionals in the industry we wanted to enrich ourselves with the knowledge of this cutting edge technology and thus took up this project as our major.

The ingenuity of this project lies in the seamless integration of planning and design of horizontal wells, performance of both horizontal and multilateral wells, along with the computer aided performance prediction.

Contents

1. Introduction

1.1 THE GLOBAL PERSPECTIVE[1]

Horizontal drilling has become a key technology used to reduce costs and enhance recoveries from producing reservoirs. Through 2001, commercial databases contained records on 34,777 horizontal wells from 72 countries. Canada (18,005 wells) and the United States (11,344 wells) were the leading countries for horizontal drilling. More than 5400 horizontal wells were recorded outside of North America. Russia, Venezuela, Oman, United Arab Emirates, Nigeria, Saudi Arabia, and Indonesia were the leading countries in terms of numbers of wells. Horizontal-drilling and completion techniques also have been applied widely and successfully in most of the important producing basins and fields throughout the world. Outside North America, IHS Energy Group records indicate that approximately 5400 horizontal wells have been drilled in more than 700 fields that are credited with 450,000 MMBO of remaining reserves. If Ghawar and other Saudi Arabian fields with active horizontal- well development programs are added, the total oil reserves being produced at least in part by horizontal wells could exceed 600 billion bbl. Venezuela, Oman, the United Arab Emirates, and Nigeria were the leading countries for which individual well records are reported. R. A. Kamal, Saudi Aramco has drilled more than 200 horizontal-development wells, in which case Saudi Arabia would rank fifth in horizontal-drilling activity, just ahead of Indonesia, which reported 212 horizontal wells. New information indicates that 1177 horizontal wells were drilled in Russia through 2001. Peak activity was reported during 2000, when 198 horizontal wells were drilled. Based on this information, Russia vies with Venezuela as the leading country for horizontal drilling outside North America. Four of the leading fields for horizontal-well drilling outside North America, as reported through June 2000,

Although the concept of horizontal drilling emerged in the 1920s, economic viability was not demonstrated until the 1980s, when pilot projects at Rospo Mare field in Italy(1982) and Prudhoe Bay field (1984) and in the Austin Chalk of Texas (1985-1987) achieved three- to fourfold productivity increases with less than twofold cost increases. From a base of 51 wells in 1987, horizontal drilling increased rapidly; it expanded to the world's active producing provinces and peaked during 1997 with 4990 wells. Horizontal drilling, which increases wellbore exposure to the reservoir, has delivered multiple benefits. Operators have used horizontal wells to revive economic production, to increase and speed recoveries, to reduce costs, and to increase rate of return.

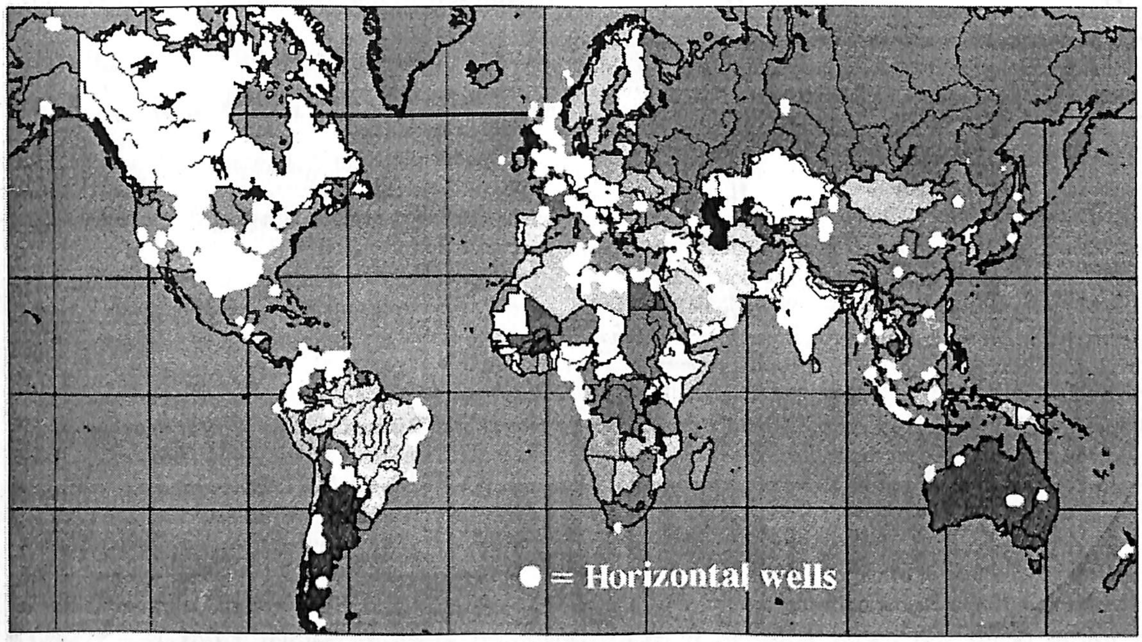
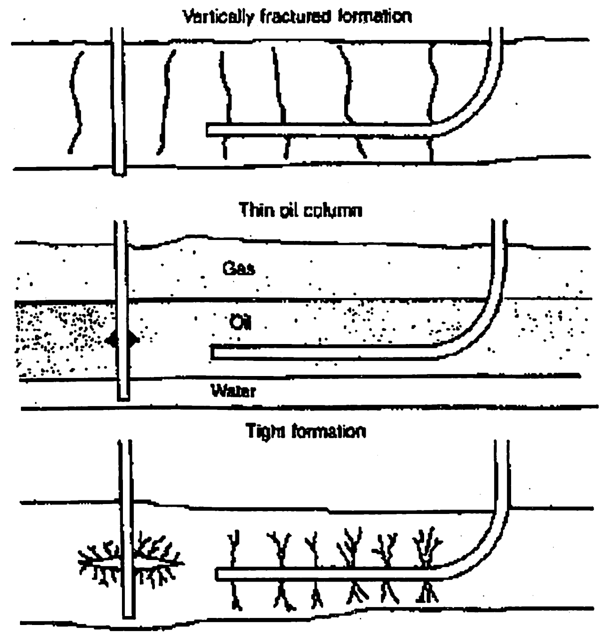


Fig 1.1Horizontal wells : Global view

Table 1.1: EXAMPLES FROM KEY FIELDS AND TRENDS

Characteristic	Field/area Example
Coning	Prudhoe Bay (Alaska)
Thermal Recovery	Belridge (California)
Waterflood	Weyburn-Estevan (Saskatchewan)
Thin beds	Cedar Hills (South Dakota)
Environment	Prudhoe Bay (Alaska)
Tar sands	Hamaca(Venezuela)

1.2 Applications[2]



Vertically fractured reservoirs, in which fractures are scarce and irregularly distributed, were one of the first applications and probably one of the most rewarding. The best example is the development of Rospo-Mare field offshore of Italy by Elf. Potential reservoirs are fractured carbonates, fractured shales, etc.

Thin reservoirs in which the oil or gas column is less than 10ft thick. If there is a bottom aquifer or a gas cap, the situation is even more favorable. The best examples are the development of heavy oil sands in Canada and thin gas sands in the North Sea.

Tight formations where multiple fracturing (4-to 6 or even more per well) along a horizontal section of the well is possible. The successful operation conducted by Maersk on Dan field in the North Sea is probably the best example. Chalky formations in the North Sea or in the U.S. (Austin chalk), or tight gas reservoirs provide a huge number of candidates for such operations. This application is probably the most promising one with U.S. operators expressing high interest in it. The great majority of the existing horizontal wells were drilled for oil and very few horizontal wells are producing gas. The rational behind this choice is more economical than technical. In fact the production improvement provided by horizontal wells is higher for gas than for oil.

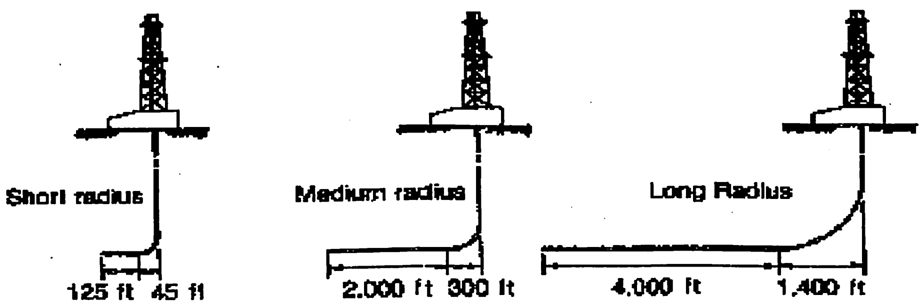
These are the main applications, but they are not the only ones. Reservoir engineers are sure to find a much greater variety of applications, especially in two-phase flow systems. Many experts in enhanced oil recovery think that the ability of horizontal wells to create parallel flow and to reduce oil velocity can boost the interest for tertiary recovery processes. In fact, in many cases it may make it economical.

Multilateral Wells[20]

A multilateral well as defined by TAML group (Technical Advancements of Multilaterals) is one in which there will be more than one horizontal or near horizontal lateral well drilled from a single side (mother-bore) and connected back to a single bore applications. In other words multilateral wells are wells in which a single wellbore is drilled to a pre-determined depth, and then multiple branches are drilled out from the original wellbore. These laterals may extend in opposite directions from each other in the same zone, or they may be drilled into different zones or formations. As with extended reach wells, multilateral wells allow much more contact with the target formation than vertical wellbores. These technologies allow the reservoir to be depleted with fewer wells than with vertical or conventional directional wells.

2. Horizontal & Multilateral Well Classification

2.1 Horizontal wells are those in which part of the wellbore is inclined 90" with respect to vertical, although less-than horizontal, high-angle wells often receive this designation. The horizontal portion of the well is often called a "drainhole." Horizontal drilling techniques can be subdivided into three different groups, depending upon the angle build rate: long, medium, and short radius (Fig. 2-1). The principal characteristics of these well types are summarized in Table 2-1[2]



Feature	Short	Medium	Long
Radius of curvature	30'-45'	300' -*500'*	1,200'-3,000'
Typical build rate	191° to 126°/100'	18.8°-11.5°/100'	4.8°-3.8°/100'
Feet drilled to horizontal	47' -71' Whipstock, articulated tools, knuckle joints, Compressive service Very specialized Single-shot ,multi-shot	471'-785'	1,885'-4,712'
Feet of horizontal hole	75'-125'	500' -*2,000'*	1,000'-4,000'
Drilling assemblies	Whipstock, articulated tools, knuckle joints, Compressive service	Conventional rotary Inverted drill string MWD, motor assemblies	Near-conventional Rotary, MWD and motor assemblies
Drilling operations	Very specialized	Conventional	Near-conventional
Surveying	Single-shot multi-shot	MWD	MWD
Directional control	Initial aim only, off whipstock	Steerable	Steerable
Logging	None	MWD	MWD
Use in existing wells	Yes	Yes	Not likely
Cased horizontally	No	Yes	Yes

2.2 Multilateral well classification[20]

An oil industry forum on the Technical Advancement of Multilateral (TAML) has been created to develop multilateral classification matrix and foster a better understanding of multilateral well application, capabilities, and equipment. The major oil & service companies all over the world are its members.

In order to properly categorize the various multilateral systems, TAML group has classified the systems into levels as a function of increasing risk and complexity.

TAML Classification System:

There are two tiers of TAML classification viz. based on

(a) complexity ranking and

(b) functional classification.

Complexity Ranking - a number ranging between 1 to 6 signifies multilateral complexity. The table below shows the complexity ranking.

Functional classification – this provides more technical detail on the major multilateral well attributes. This is divided into two sections:

- Well description
- Junction description

Well Description

The well description is broken down into four major categories

1. **New/Existing Well.** Two distinct applications where issues such as the method of casing exit and the ability of achieving pressure integrity at the junction require different approaches

2. **Number of Junctions.** Important to a well's complexity. Currently the majority of wells are drilled dual lateral however as the technology advances and experience with the technology is gained the average number of laterals drilled will increase.

3. **Well Type (Producer –with or without artificial lift, Injector or Multipurpose).** The functionality requirements of a producer are different from that of an injector, particularly the levels of pressure integrity required at the junction and pressure exerted during well shut-in.

4. **Completion Type (Single, Dual or Concentric Bore).**
Describes the completion above the production packer, which will in turn have an impact on the type of equipment required at the junction.

Junction Description

1. **Connectivity.** For a dual lateral, this indicator would be the same as that included in the Tier 1 ranking. Wells with more than one junction would have a unique level indicator for each junction, which may or may not be similar. The most complex junction would determine the overall well complexity ranking. In addition to level, a pressure rating would also be included where applicable (e.g. Level 5 – 5000 psi)

2. **Accessibility (No Selective Re-entry, Re-entry by Pulling Completion or Through Tubing Re-entry).** Describes the level of re-entry, which is catered for during the life cycle of the well. Although window apertures can be re-entered on a trial and error basis by utilising bent joints, if there is no fixed datum from which the aperture can be easily located the lateral is deemed to have no re-entry capability. Table 3.3 illustrates the accessibility options.

3. **Flow Control (None, Selective, Separate, Remote Monitoring or Remote Monitoring and Control).** Describes the degree of control over the production or injection fluid flow across the junction. Monitoring includes any of the following: Pressure, Temperature, Flow, Sand production, Scale deposition, Saturation profile, Seismic, SCSSSV status, Well integrity, Corrosion.

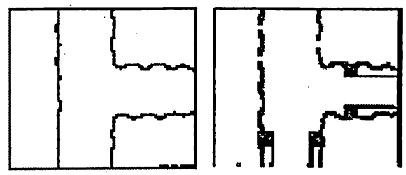
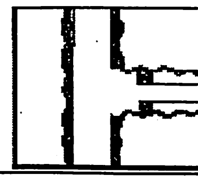
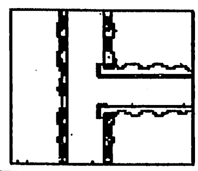
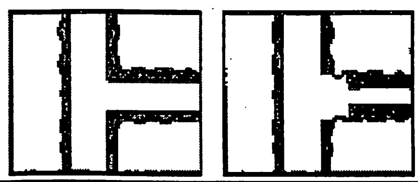
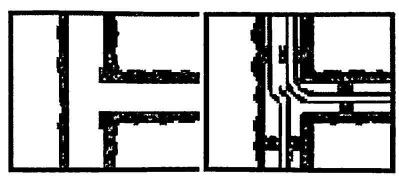
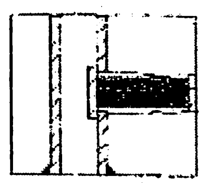
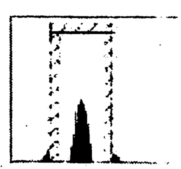
Level	Description	Illustration
1	Open/ Unsupported Junction Barefoot mother-bore & lateral or slotted liner hung-off in either bore	
2	Mother-bore Cased and Cemented Lateral Open Lateral either barefoot or with slotted liner hung-off in open hole	
3	Mother-bore Cased and Cemented Lateral Cased but not Cemented Lateral liner 'anchored' to mother-bore with liner 'hanger' but not cemented	
4	Mother-bore and Lateral Cased and Cemented Both bores cemented at the junction	
5	Pressure Integrity at the Junction Straddle packers or (integral) mechanical casing seal .(Cement is not acceptable)	
6	Pressure Integrity at the Junction Achieved with the casing (Cement is NOT acceptable)	
6S	Downhole Splitter Large main well bore with 2 (smaller) lateral wellbores of equal size	

Fig 2.2: TAML Complexity Ranking Classification

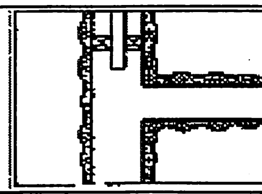
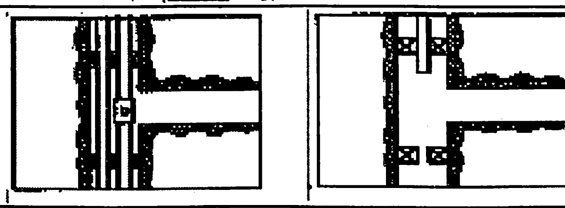
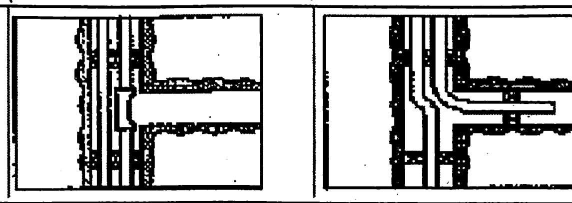
Description	Illustration
No selective re-entry	
Re-entry by pulling completion	
Through-tubing re-entry	

Fig 2.3: Example of Accessibility Options

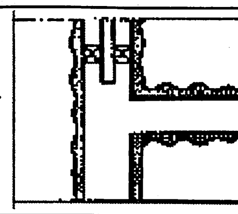
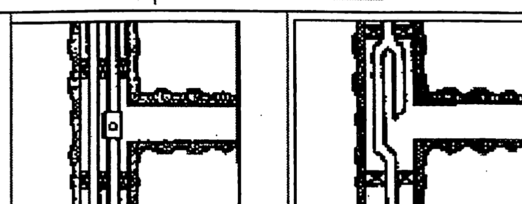
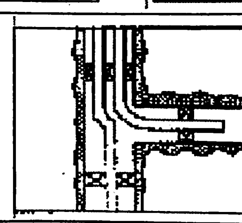
Description	Illustration
Commingled	
Selective	
Separate	

Fig 2.4-Examples Of Flow Control Options

3. Geological aspects and Applications

The applications where a horizontal wellbore will enhance production and economic return on investment are as broad as the choice of geologic horizons. Theoretically all reservoirs can benefit from horizontal wells but often these reservoirs may be just as effectively produced using conventional vertical techniques.

For example consider a horizontal wellbore in a high permeability homogeneous gas reservoir. No natural barriers traverse through the reservoir and the reservoir can be easily hydraulically fractured to overcome the pressure drop near the wellbore caused by drilling damage and gas turbulence. The ultimate percentage of reserves recovered will be high and the flowrate will deliver the reserves in an acceptable time frame. In this example, a horizontal well will not significantly increase return on investment or improve on ultimate recovery from the reservoir. If the same reservoir is internally subdivided by shale drapes as in a channel point bar system, the horizontal well will significantly increase the ultimate recovery of oil and gas from the reservoir.

To fully utilize the potential of a horizontal well, the geologists must have a clear understanding of both vertical and lateral reservoir characteristics. The drive mechanism and fluid characteristics in the reservoir system are equally important. Once a candidate has been selected, the geologists must work closely with the drilling and completion engineer to match hole azimuth to reservoir character and geometry.

Horizontal Well Applications[2]

1. **Gas & Water Coning**

With production, reservoir pressure is drawn down around the wellbore, elevating the level of oil/water surface in the vicinity of the wellbore. The height of this rise reflects oil pressure immediately above contact. The slope of the oil/water surface reflects the horizontal pressure gradient at the contact. As the oil production rate is increased, the pressure gradient is increased and the water rises even more. Eventually, the critical the production rate is reached: water rises to the wellbore and water breakthrough results. The critical production rate is dependent on the density differential of the oil and water and the oil viscosity.

Horizontal drilling can place the wellbore near the top of the reservoir, well away from the oil/water contact. The volume of oil displaced prior to water breakthrough is the volume within a cone around a vertical well. In a horizontal well, the cone becomes a crest and is able to capture a much larger volume of oil. Due to the length of the wellbore, drawdown is minimized while still maintaing production. This reduces the horizontal pressure gradient and increases the width at the base of the crest.

Problems can occur if reservoir permeability along the horizontal wellbore is variable. Water may be prematurely produced from a high permeability section and negatively effect the overall well performance.

2. Low Permeability Reservoirs

In low permeability reservoirs, the unstimulated vertical wellbore is often not capable of economic flow rates. However, with hydraulic fracturing, low permeability reservoirs can become economically viable if a significant fracture length is placed in the formation. The fracture must overcome wellbore damage and positively stimulate the reservoir. If the reservoir is sandwiched between formations that will not contain the fracture, then successful hydraulic fracturing is difficult.

Horizontal wellbores can be used to place a flow path through the reservoir as an alternative to hydraulic fracturing. Even if the formation is easily fractured, horizontal wellbores have an inherent advantage in low permeability reservoirs that require tight well spacing. Only one wellbore, one surface facility, and one tie-in are required for a long horizontal well. The well can be fractured at intervals along its length and achieve the effect of multiple vertical completions.

Heterogeneous Reservoirs

Understanding of the heterogeneous character of a reservoir and the directional relationship of reservoir permeability is the key to achieving successful horizontal completions.

1. Carbonate Systems

Porosity patterns in carbonate reservoirs are often complex and difficult to predict. The horizontal well can be used to develop this type of reservoir by connecting areas of high permeability rock that are separated by low permeability sections. In the case of a carbonate reef, the azimuth should be selected to run parallel to the reef margin as drilling across the reef may result in a wellbore that drills into progressively poorer reservoir rock within the reef flat or lagoon.

2. Channel Point Bars

Channel point bar sands formed by lateral accretion within fluvial streams often contain non-permeable clay layers, deposited during the waning flood stage of river flow. These layers, often referred to as shale drapes, present problems in achieving high recovery factors because they inhibit lateral flow to the wellbore. Development by water flooding often shows complicated production performance, poor development results and low ultimate recovery. If the orientation of the point bar can be determined, a horizontal well can be directed to penetrate multi-impermeable sand wedges which would normally be isolated from wellbore by impermeable shale drapes. This can lead to increased ultimate recovery from the reservoir.

3. Braided Stream System

Braided streams often contain low permeability lenses created by pods of finer sediment within the channel fill. Such pods or lenses are usually oriented with their long axis parallel to the stream direction. Consequently, the direction of fluid flow will generally be along the primary axis of the stream system. In such a case, a vertical well will produce reserves from a long narrow section of the reservoir with minimal contribution from channel sands located adjacent to the wellbore, but in a direction normal to the streams direction of flow. A horizontal wellbore drilled normal to stream flow will increase recovery by accessing more channel segments.

4. Fracture Systems

Natural fracture systems within the reservoir will greatly enhance the production of oil and gas by providing natural flow paths for reservoir fluids. Some reservoirs depend exclusively on this system to produce oil and gas. In such cases, if a fracture system is not encountered in the wellbore, the well is not capable of economic production. Horizontal wells greatly increase the probability of encountering a fracture system and significantly reduce the dry hole risk. Extensive fracture systems which extend into underlying water zones may be detrimental to production and should be avoided.

Drilling parallel to shale drapes or parallel to a braided stream axis will not optimize horizontal well performance. In fractured systems the wellbore must be drilled perpendicular to the fracture direction to encounter new fracture systems and new reserves. Regional core and log data combined with vertical pilot hole data should be used to determine directional reservoir properties before selecting the optimum hole azimuth of the horizontal well.

Planning, design and supervision[3]

Following candidate selection and classification, well planning, design and supervision should be commenced using the greatest care possible. Planning new wells for the horizontal application offers flexibility, not only in horizontal hole diameter and length, but also in the types of tools and techniques that may be used for completion.

Planning should start from the desired conditions in the horizontal section of the hole and proceed back up the hole, That is, well bore geometry and equipment selection will depend upon the diameter desired in the horizontal section. Hole diameters as large as 9 7/8- in. may be used in horizontal sections, which is significant because it affords 500% more formation exposure to the well bore than does a 6 1/4-in. hole diameter, for example. Therefore, horizontal hole diameter has economical as well as technical implications. Not only do the large diameter horizontal holes improve recovery, they also allow more flexibility in use of completion tools and other drilling procedures.

Design and planning for horizontal wells can be considered in four separate phases, namely completion, drilling of the horizontal section, drilling of the angle build section, and drilling of the vertical section. Design of each phase is dependent upon the other.

Major considerations in the completion stage should include: hole size, logging, open or cased hole, slotted liner or cemented casing, centralization of casing or liner, cementing procedures, perforating and treating requirements.

Drilling the horizontal hole to maximize lateral extension demands emphasis on drill string design, selection of drilling fluid, hydraulics, mud cleaning, stabilization, selection of steering and directional control equipment, well control, bit selection and downhole motor requirements.

These designs are all interrelated, and should be optimized where possible. For example, hydraulics can be influenced and controlled by drill string design, drilling fluid properties, mud motor and MWD requirements. Well control must be absolute, as kicks encountered in extended horizontal hole can be more serious than those encountered while drilling vertical holes having less producing interval exposed to the well bore. The angle-build or deviated portion of the well requires particular emphasis on selection of kick-off point and angle of build to permit intersection with the desired target. Drill string design, drilling fluid, hydraulics, stabilization, downhole motor, bit selection and MWD requirements are inclusive in design consideration. Where incompetent or troublesome formations are encountered, this portion of the hole must sometimes be cased and cemented prior to initiating the horizontal section.

Substructures must accommodate blowout preventor stacks designed for unconventional drill strings. Mud pit design and flexibility, along with mud mixing capabilities, should be determined. Mud cleaning apparatus such as shale shakers, desanders or centrifuge will in all probability be required. Finally horizontal drilling is a more dehcate procedure than most conventional vertical drilling; therefore, high quality rig supervision is another consideration when electing to undertake these wells. The best of planning and design cannot make up for poor execution.

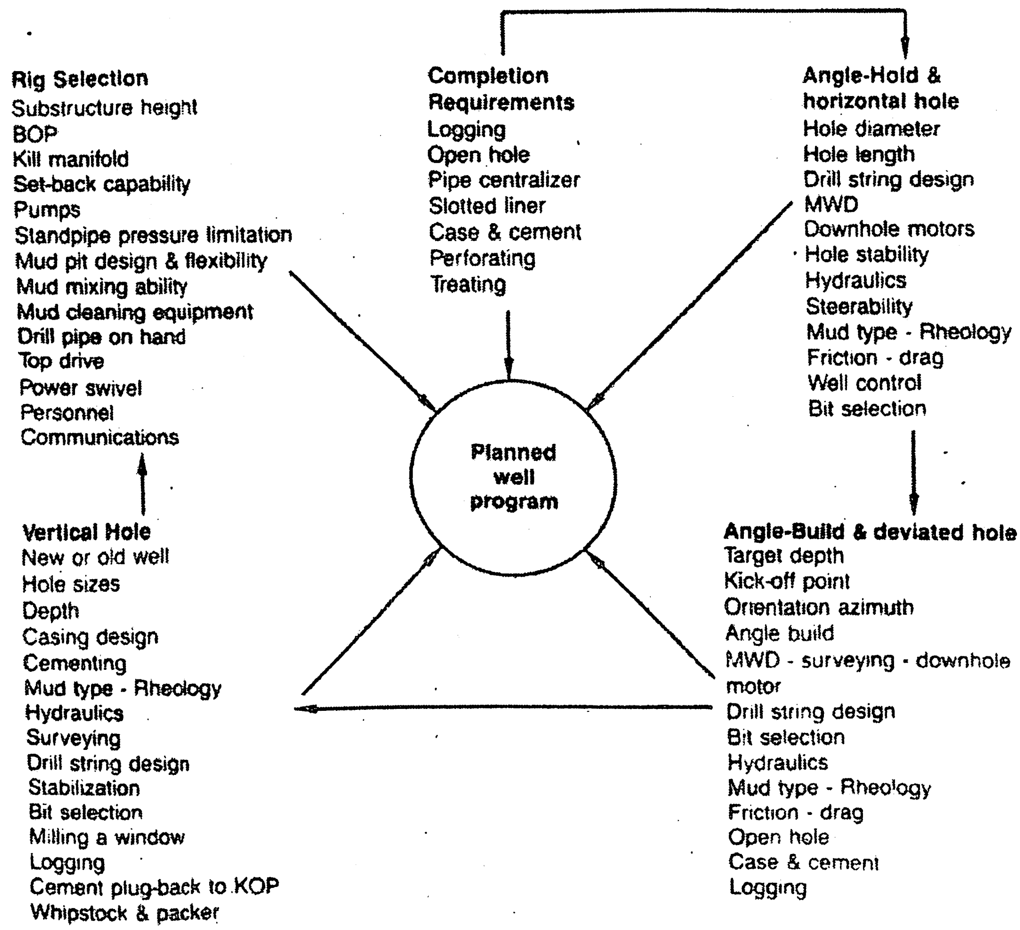


Fig 3.1: Planning for drilling and completing a horizontal hole is a complex interrelated process. The advent of computers has improved the accuracy and speed of this process.

4. Evolution of Steering Technology

Rotary steering technique has seen a dramatic resurgence driven by the need to design and plan more complicated directional wells. The evolution of directional drilling trajectory control techniques from conventional rotary assemblies through steerable motors to full 3D rotary steering control systems, in addition to the corresponding evolution of survey and logging methods, has been equal to the challenge of these more complex, designer and extended reach wells. The evolution of rotary steering systems and their use in various directional wells is illustrated as below in the following figure.

Drilling Tool Type	Deflection Tool Type	Well Inclination	Survey Method
D500 Single-Lobe Motors	Bent Sub	25-35 deg Type I, II, III Wells	Singleshot
Multi-Lobe Motors	Bent Sub	25-55 deg Type I, II, III Wells	Steering Tool
Steerable Motors	Adjustable Bent Housing	25-90 deg Type I-III & Horizontal Wells	MWD / LWD
Dynamic Rotary Steerable Tools	Pistons or Paddles	25-90 deg Type I-III Horizontal & ERD Wells	MWD / LWD
Static Rotary Steerable Tools	Circumferential Forces	25-90 deg Type I-III Horizontal & ERD Wells	MWD / LWD

Figure 4.1

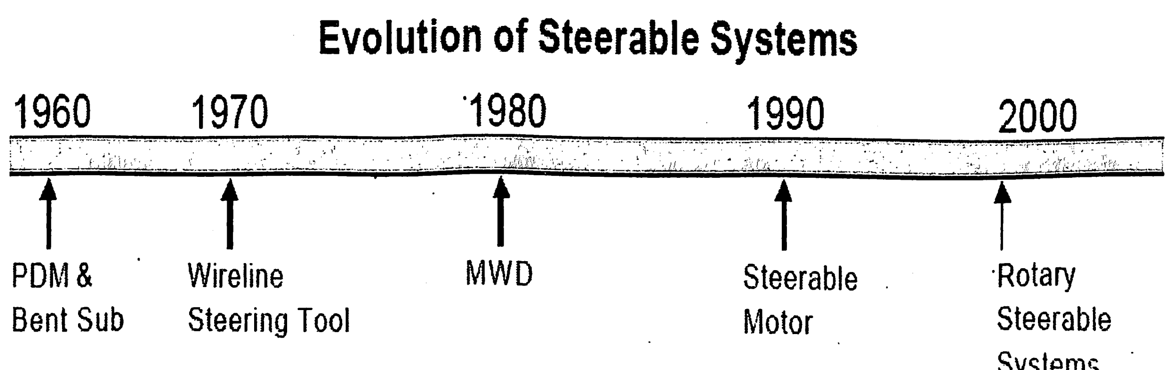


Fig 4.1 and 4.2 : Evolution of steering technology and steering tools

4.1 ROTARY STEERABLE SYSTEMS[8,9]

Fundamental limitations of mud motors

Steerable motors provide a capability that is essential to the oil industry. Unfortunately, this technology has significant limitations and inefficiencies that affect its ability to continuously support increased operational demands. Drilling with steerable motors is divided into two activities: Sliding and rotating (Fig. 2). Sliding involves precision guidance of the assembly towards a prescribed target. Rotating involves no active guidance of the trajectory. Problems associated with each of these states are listed in Table 1

Most of the limitations and inefficiencies are related to the need to drill a portion of the well without string rotation or concerns related to motor performance. Continued evolution of the steerable motor system is not likely to solve most of these problems since they are related to the fundamental characteristics of the steerable-motor directional system.

Table 1

PROBLEMS

Sliding	Rotation
• Inability to slide	• Vibrations-motor and MWD failures
• Maintaining orientation	• Accelerated bit wear
• Poor hole cleaning	• Poor hole quality for logs.
• Low effective ROP	• Poor performance in air
• High tortuosity	
• ECD fluctuations	
• Differential sticking	
• Buckling and lock up	
• Build rate formation sensitive.	

Rotary-steerable systems

Rotary steerable systems are directional tools that allow the well trajectory—inclination and azimuth—to be actively guided while rotating the drillstring. The concept for rotary-steerable directional systems predates the common use of mud motors (PDMs). These systems include many of the fundamental concepts that are being used today. Fig. 3a shows a system, patented in 1955, that used a non-rotating sleeve to direct the bit in a specific direction. The patent describes the objective of the tool as "to cause the drill collar to assume a slightly inclined position with respect to the axis of the hole so the bit will be laterally directed." Fig. 3b shows another system patented in 1959 that used hydraulically activated guide shoes near the bit to control the drilling trajectory in a similar manner. The guide shoes, located on non-rotating housing, were powered by mud pressure and could be activated and retracted without tripping the drillstring.

Fig. 2

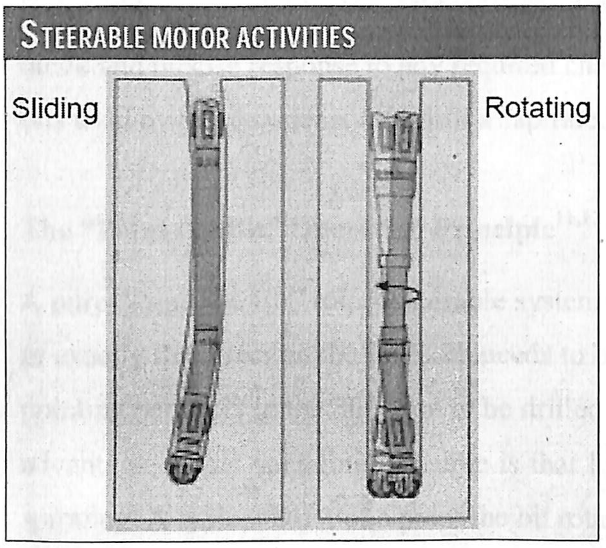
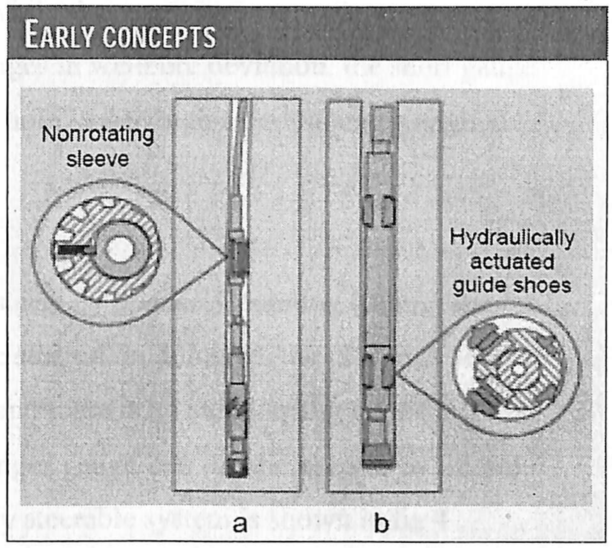


Fig. 3



Current concepts

Most RSS devices require a stable platform from which to apply an offset or force to the wellbore wall. Typically, they utilize some form of instrumented, "non-rotating" housing as the platform from which to apply the offset or force. "Non-rotating" does not normally mean that the outer "sleeve" device never rotates with the drillstring, but that it is de-coupled from the rotation of the drillstring in such a manner as to prevent actuation mechanisms from having to work at a rate equal to drillstring RPM. Such devices are characterized as "static".

A few devices use alternative methods for deflecting the drillstring and achieving directional control. These tools do not have a de-coupled sleeve type device, with an internal mandrel and they rely upon rapid electro-mechanical actuation to keep the vector forces in synchronization with drillstring rotation. These tools have high capital and running costs and suffer from maintenance and longevity issues. Such devices are characterized as "dynamic".

The "Push The Bit "operating principle

A pure "Push the Bit" rotary steerable system steers simply by applying a side load to the bit. This forces the bit's outer cutting structure and gauge to cut sideways into the formation to drill a curved hole in that direction. Systems employing this principle are restricted to very short gauge bits (typically less than 2-in. gauge length) where the gauge is set with an active highly cutting structure. While these systems are agile, permitting a quick and precise response to any required changes in wellbore deviation, the short gauge bits used by these systems may drill a "spiraled hole" when high side-loading is applied.

The "Point the Bit" Operating Principle[11,12]

A pure "Point the Bit" rotary steerable system steers by precisely pointing (tilting) the bit in exactly the direction the wellpath needs to be steered. In doing so, the drill bit's face is pointing perfectly in the direction to be drilled and there is no side loading on the bit. The advantage of this operating principle is that longer gauge bits can be used to avoid hole spiraling. A typical BHA of a point the bit rotary steerable system is shown in fig 4

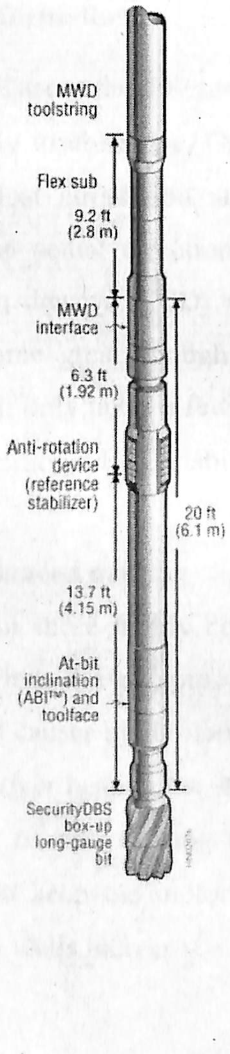


Figure 4a

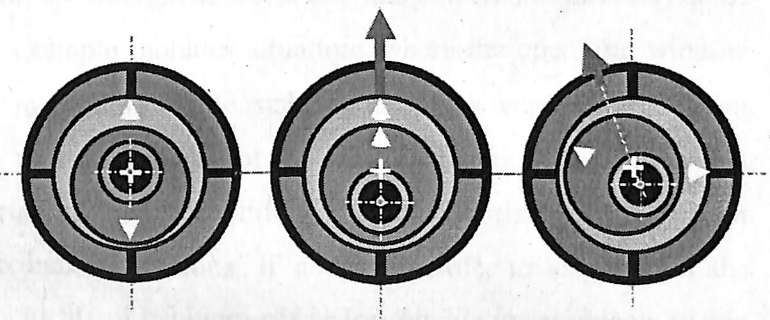


Figure 4a – A typical point the bit RSS BHA
Figure 4b: Deflection of the driveshaft by selective orientation of the internal and external eccentric rings. In the first diagram (A), the eccentric rings or cams are positioned opposite each other, thus canceling out the eccentricities and keeping the shaft straight. In the second diagram (B), the cams are completely aligned, generating the maximum amount of deflection and hence build rate. This orientation can be rotated around to deflect the wellbore in any direction. The cams can be positioned to an intermediate position for less than 100% build rate, as shown in the third diagram (C).

EDGE OF THE TECHNOLOGY

Hole cleaning

Improvements in hole cleaning are one clear advantage of continuous pipe rotation and can be achieved while reducing the time spent on hole cleaning activities, including the need for sweeps and special drilling-fluid treatments (Fig. 5).

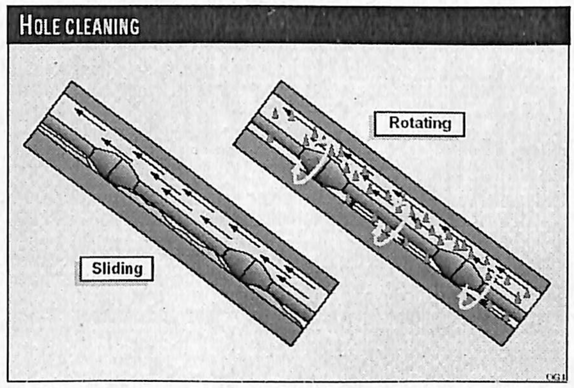


Fig 5: Sliding inhibits hole cleaning

Problem formations

There are cases where formation considerations make operating steerable- motor systems particularly troublesome. One example includes situations where the operating window between lost circulation and maintaining hole stability becomes very narrow. Even though the actual directional trajectory may not be very challenging, the equivalent circulating density (ECD) variations between sliding and rotating the steerable motor may become great enough to make it tedious, if not impossible, to stay within the window. It only takes a few incidents of packing- off or lost-circulation problems to pay for the additional ECD stability afforded by rotary-steerable systems.

Underbalanced drilling

The use of these highly compressible fluids causes two types of problems with mud motors. First, the compressibility of the air significantly affects the efficiency of the motor and causes high rotational speeds when the bit load is removed. This can affect the motor by over heating the stator and is further compounded by absorption of the gas into the stator rubber, causing it to swell. The compressibility of the fluid also makes it difficult to keep the motor properly loaded and oriented, particularly as the reach of horizontal wells increases.

Deep hot wells

Directional work in deep, high-temperature wells is limited by the capability of Moineau motors to operate under such conditions, especially where oil-based mud is used. This limitation affects the ability to effectively use horizontal completions in these wells. In many cases, the pressure environment and subsequent casing programs dictate that this work be done in a small-diameter hole and often at relatively high build rates. Alternative motors such as turbines and other all metal motors may operate more effectively at higher temperatures, but they do nothing to reduce the problems of orienting small diameter motors in deep wells.

4.2 SOLID EXPANDABLE TUBULARS[5,6]

Operators face significant loss of inside diameter (ID) in the course of the normal drilling process, during re-entry and deepening of existing wells, or when installing additional casing strings to remediate well problems. The industry has confronted this dilemma with innovative problem solving that stretches the boundaries of physics in the guise of solid expandable tubular technology. Successful applications have proven the technology's reliability in a variety of conditions, environments and as a solution to problems like gas shut-off, subsidence repair, water shut-off, lost circulation, and remediation of wells slated for abandonment.

This original procedure takes the steel beyond its elastic limit into the plastic region of the stress-strain curve while remaining safely below ultimate yield. The pipe is taken above the elastic limit and plastically deformed with a solid tapered cone as the cone is pumped through the liner with cement pumps or the rig pumps. Engineers design the liner's final dimensions by checking the OD of the expansion cone, which determines the expanded liner's ID.

In a drilling application, solid expandable tubular technology reduces the telescopic effect created by using multiple casing strings in deepwater or extended reach wells, thereby preserving valuable hole size. The results of using SET are significant increases in production and reductions in cost and time. Because of their versatility and adaptability to many drilling conditions and situations, they are a practical element in wellbore design. With close to 100 miles (160 km) of pipe expanded, this technology is proven and economically viable.

Run procedure

During installation of an expandable liner, crews run the expansion cone launcher system first, followed by the remainder of liner, including the overlap section with the external elastomer seals (Fig. 1). With the liner hanging from its top in the rig floor slips, the crew picks up the drill pipe, runs it through the liner, and screws it into the cone. After make up of the drill pipe to the cone at the liner's bottom, the rig lifts up to remove the false floor and slips and runs to TD in the conventional manner.

Once the expandable liner is on bottom, the rig can circulate down the drill pipe and up around the outside of the liner.

Expansion process

To initiate the liner expansion process, a latch down plug is pumped down the drill pipe, which seats into the bottom of the expansion cone's launcher system creating a pressure chamber below the expansion plug.

As crews continue pumping mud down the drill pipe increasing pressure in the chamber, the pressure acting on the expansion cone cross sectional area drives the cone up into the liner. The driller maintains the string weight. The drill pipe rises on the rig floor as mud is pumped and the liner expands. In the case of the openhole solid expandable liner, the expansion cone moves upward during expansion, causing the pipe to shorten and lose wall thickness as material is consumed with the increased pipe diameter.

The pipe experiences 4-5% reduction in length and 3-4% reduction in wall thickness. The rig can stand drill pipe back in the derrick, which is the fastest way, or laying down singles as it proceeds with the liner expansion process.

Solid Expandable Openhole Liner Systems

The openhole liner system (Figure 2) can be planned into the well construction to minimize the telescoping effect. Solid expandables minimize well slimming while adding strings for needed depth. The openhole system can be used as a contingency drilling liner in any well during the drilling phase. Running this drilling liner maintains hole size when an unforeseen geologic anomaly or problem is encountered.

Solid Expandable Openhole Cladding System

The openhole cladding system is an expandable string that is run and installed in the open hole to:

- isolate an unstable formation;
- isolate a water flow; and,
- shut off water influx in an openhole completion.

The openhole cladding system installation process is similar to that of the openhole liner with the exception that it is not tied back into the base casing. Elastomers are configured to seal against the formation. The seal efficiency will be a function of the rock properties where it is set. Porosity, permeability, and rock hardness all affect the seal capabilities.

Solid Expandable Cased-Hole Liner System

The expandable cased-hole liner system enables operators to repair existing damage or worn casing for deeper drilling or other contingencies. The system makes it possible to upgrade exploration grade casing to a sturdier production casing with minimal loss of ID. The system can be used to shut off perforations in production casing for re-completion or for deepening the well. This expandable system allows for enhanced control of existing injectors and producers by shutting off unwanted gas or water production. The system has also been used to re-connect a severed wellbore due to subsidence from formation movement.

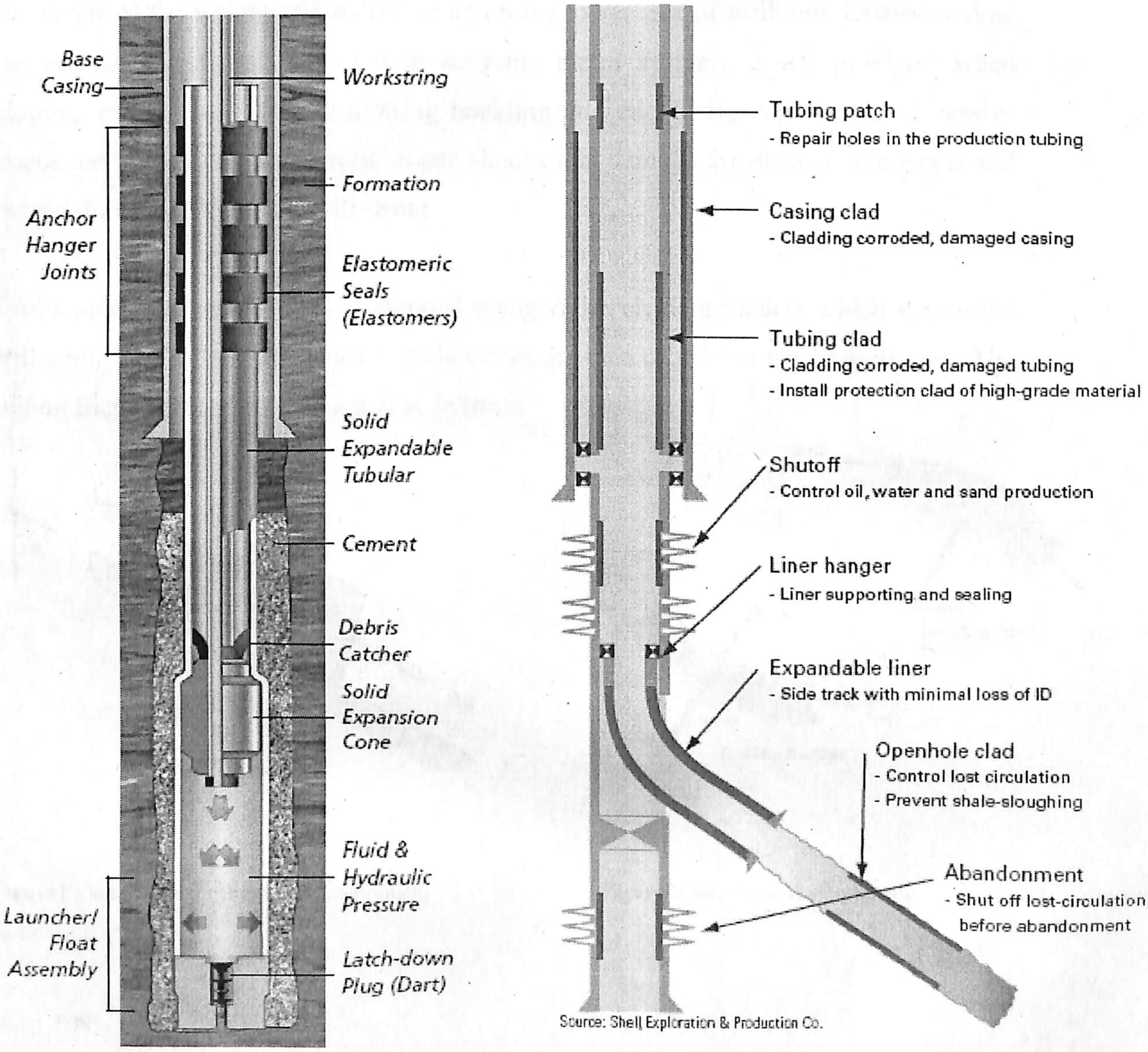


Fig 2: Illustration of a solid expandable tubular and applications of SET

5.1 Torque and Drag Theory[8,16]

Torque and drag issues are particularly prominent in deviated and horizontal wells, due to the effects of the weight of the drill string on the lower side of wellbore. Excessive drag can prevent directional control with steerable motor systems, create problems when tripping, cause stuck pipe, drill string buckling and exceed rig capabilities. Excessive torque can damage rig equipment, create shocks that damage drillstring components and exceed the capacities of the drill string.

Torque and drag modeling is performed using finite element models which divide the drill string into individual elements. Side forces are then calculated for each element. The sliding friction force F is calculated as follows:

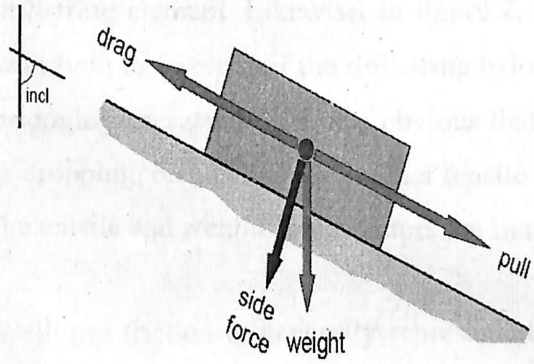


Figure1 : side force for the weight component component

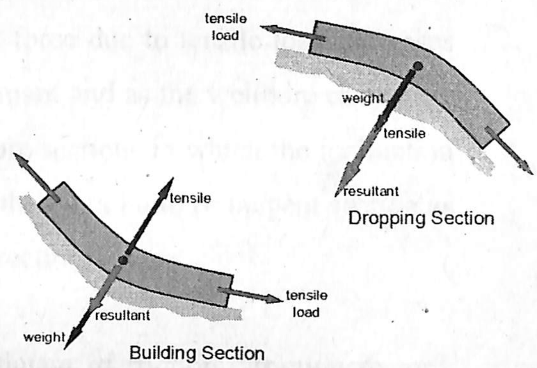


Figure2: side force due to tensile

$F = \mu * N$

where N is normal contact force between drill string and wellbore, and μ is the coefficient of friction, or 'friction factor' used to represent the average conditions in the wellbore. The "friction factor" is the most important element needed to calculate either the "pick up" or "slack off" load or the torque needed to rotate the string.

The rotating friction, or torque, is determined for each element as follows:

$F = \mu * N * r$

where r is the radius of the drillstring element.

Sum of the sliding forces for the entire drillstring is the hookload weight and the sum of the rotating forces is the torque required to turn the drillstring.
Torque and drag, both are related to the sideforces and friction generated in the wellbore.

Sideforces are the normal, or perpendicular, forces exerted on each element of the drillstring. The two major contributors to torque and drag are the weight of the drillstring and the tensile load across each element of the drillstring. From Figure 1, it can be clearly seen that as the inclination of the wellbore increases, so does the normal force for each drillstring element. Likewise, in figure 2, the normal force due to tensile load increases with both the weight of the drillstring below each element and as the wellbore curvature, or dogleg, increases. It is also obvious that the wellbore sections in which the inclination is dropping, results in much higher tensile sideforces then in a build or tangent section as the tensile and weight force vectors are in the same direction.

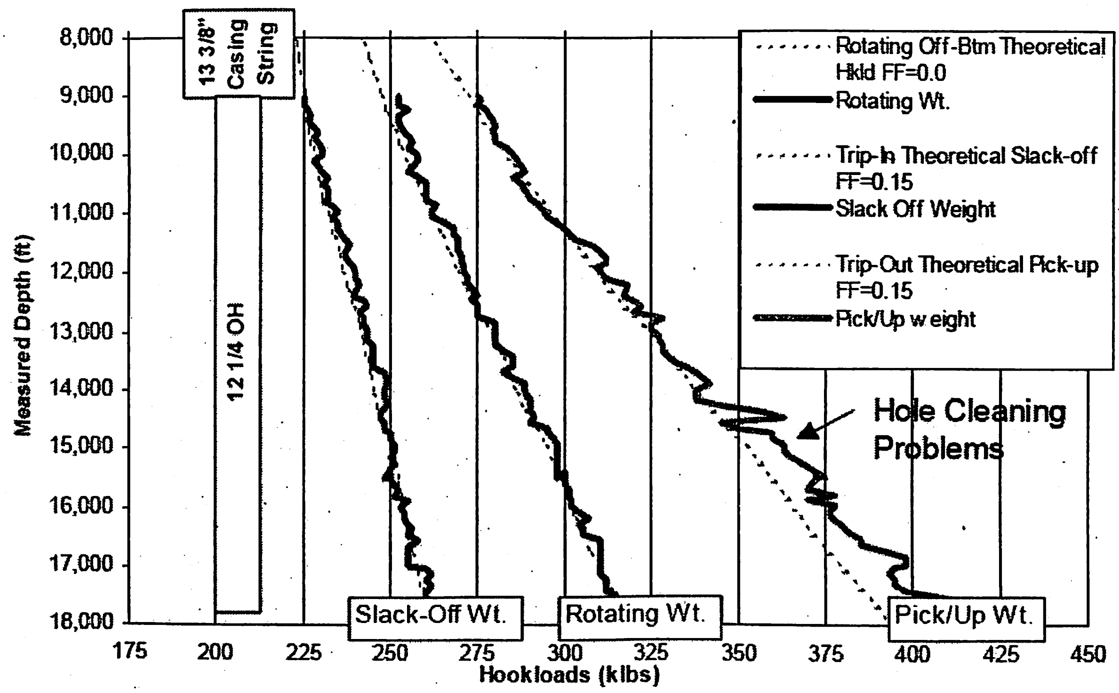
Wellbore friction is generally represented as a coefficient of friction, "friction factor", and is the force opposing motion of the drillstring. Wellbore friction is a function of the materials interacting and the lubricity of the mud in the wellbore. During drilling, the surface measurements of torque and hookloads are invaluable indicators of hole condition. By plotting the pick-up, slack-off, rotating weights as well as drilling torque, trends can be identified. Increases in torque and drag can be a warning sign of problems such as:

- the build-up of a cuttings beds on low-side of the wellbore
- wellbore stability issues such as wellbore break-outs and hole enlargements
- tight hole conditions; i.e., reactive shale, key seats, differential sticking,
- tortuosity in wellbore, especially microtortuosity and wellbore spiraling, and

• rig equipment problems; i.e., topdrive bearing failures, high riser bending, torque gauge calibrations, etc.

For wellbores in good condition, the primary source of drag is sliding friction due to contact between the drillstring and the wellbore.

Example of a hole cleaning problem[17]



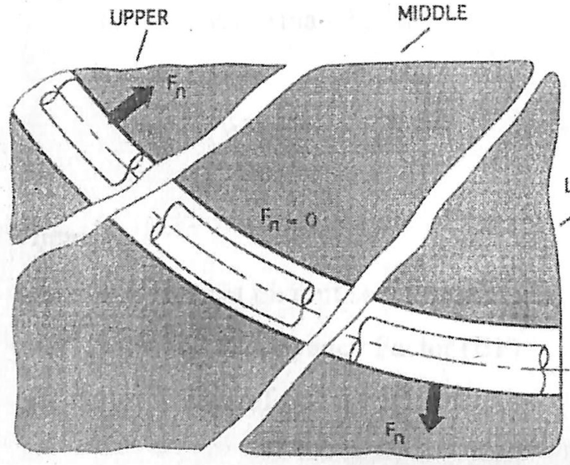
This is a 62-degree well where the 12 ¼" hole section is the tangent section.The dotted lines indicate theoretically computed loads using the available torque and drag model. The rotating off-bottom, pick-up and slack-off hookloads are used to calibrate the torque and drag model. Hookload points are taken after drilling out the casing shoe at every connection. In the first few connections out of the casing shoe, the hole is relatively clean of cuttings, in gauge, and is the best time to determine "clean hole" friction factors for the well. Once the rotating weight is correct, the friction factors used in the theoretical model are adjusted until the pick-up and slack-off hookloads match the theoretical curves. Comparing the theoretical and actual loads, one can clearly see that the pickup loads continuously increase after a depth of around 14700ft, while the other two loads follow the the trend of the theoretical curves. Thus we can interpret that hole cleaning problems (cuttings buildup) have developed and are becoming continuously worse .Thus remedial action should be taken to eradicate the problem

5.2 DETERMINATION OF TOTAL TENSIONAL LOAD INCLUDING DRAG FORCE

The well profile of a typical deviated well can be divided into 3 major sections, namely

- Build-up- inclination increases with increasing depth.
- Drop-off- inclination decreases with increasing depth.
- Slant hole- inclination remains constant with increasing depth.

The following discussion for horizontal wells, is considered for build up and slant hole sections only.



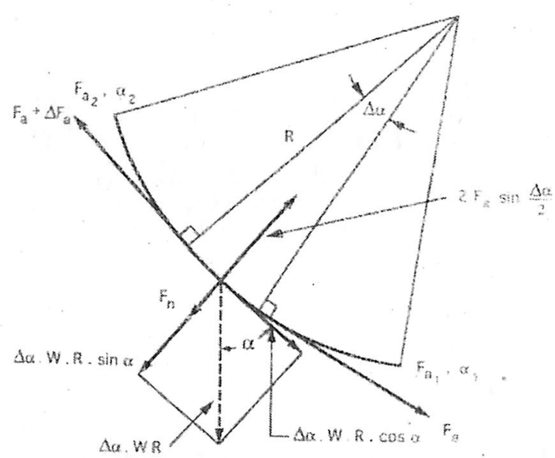


Fig 1 and 2: Possible direction of normal forces in a buildup section ;Forces acting on a small element within the buildup section.

BUILD-UP SECTION

Besides frictional factor, borehole frictional drag is also controlled by direction and normal force. The normal and axial forces acting on each section is presented in the adjacent figure. From the free body diagram, the normal force can be expressed as:

$$F_n = 2F_a\cos\left(90 - \frac{|?\,a|}{2}\right) = 2F_a\sin\left(\frac{|\,?\,a\,|}{2}\right)$$

Where,

F_a = axial force on unti section, lbf

? a = angle subtended by unit section at radius R

In as much as $? a << R$, $\sin\left(\frac{? a}{2}\right) \sim \frac{? a}{2}$

Therefore, $F_n = 2F_a \frac{? a}{2} = F_a\, ? a$

Considering, buildup section in general, the resultant normal force while pulling out of hole is the vector sum of normal components of weight and axial force of the unit section.

? a ?

$$F_n = ?a\ WR\ \mathrm{Sin}a - F_a\, ?a$$

$$= ?a\ (WR\ \mathrm{Sin}a - F_a), \qquad -3$$

Where,

W = weight on unit section, lb/ft.

= Wx * Buoyancy Factor (BF)

R = Radius of Curvature, ft

The magnitude of drag force, F_d, which acts in opposite to pipe movement is given by:-

$$F_d = - f_b \left| F_n \right| \qquad -4$$

Or,

$$F_d = - f_b \left| ?a\ WR\ \mathrm{Sin}a - F_a\, ?a \right| \qquad -5$$

Where,

f_b = Borehole Friction Factor,

$|F_n|$ = Absolute value of normal forces, lbf

The incremental axial force, ? F_a (F_{a2}-F_{a1} = ? F_a> 0) over incremental arc length

$(a_2 - a_1) = ?a < 0)$ when casing is being pulled (indicated by negative ? aWRCosa), is given by :-

$? F_a = ¦ F_d¦ - ? aWRCosa$ -6

Or,

$? F_a = f_b¦ ? aWRSina - Fa? a¦ - ? aWRCosa$ -7

Therefore at equilibrium, following differential equation is obtained.

$dF_a/da = - f_b¦ WRSina - Fa¦ - WRCosa$ -8

if casing is in contact with the upper side of hole (WRSina- Fa) <0.

Therefore,

$dF_a/da = - f_b (Fa- WRSina) – WRCosa$ -9

$dF_a/da + f_bFa = WR (f_b Sina – Cosa)$ -10

The above differential equation could be solved to get following results.

For upper most section,

$Fa_2 = K_BFa_1 + (WR/1+f_b^2) [(1- f_b^2) (K_B Sin\ a_1- Sin\ a_2) + 2 f_b (K_B Cos\ a_1- Cos\ a_2)]$

– 11

For intermediate section,

$Fa_2 = Fa_1 + WR (Sin\ a_1- Sin\ a_2)$ – 12

For lower section,

$Fa_2 = K_BFa_1 + (WR/1+f_b^2) [(1- f_b^2) (K_B Sin\ a_1- Sin\ a_2) - 2 f_b (K_B Cos\ a_1- Cos\ a_2)]$

– 13

Where,

$K_B = e^{\wedge}(f_b (a_2-a_1))$ for buildup.

$R = (l_1-l_2) / (a_1 - a_2) = [(180/?\ )^* (1/a)^*(100/1)$

Slant Section

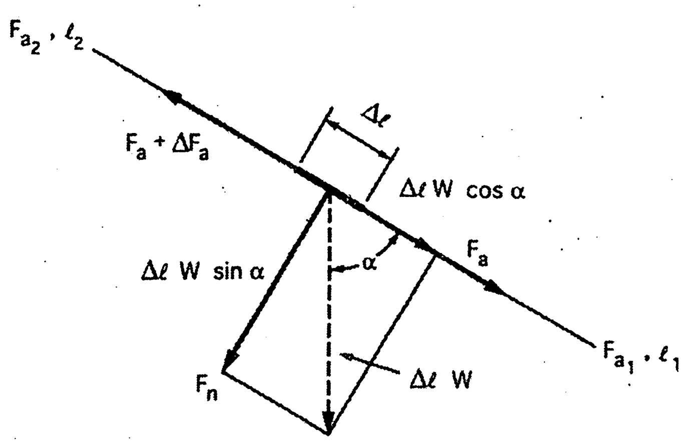


Fig 3: Forces acting on a small element within the slant section.

For the slant portion of borehole, forces acting on a unit section are presented in adjacent figure.

At equilibrium, the resulting differential equation is:

$dF_a /dl = W (F_b \sin a + \cos a)$ – 14

The tensional load is controlled by type of operation that is pulling or running in. At equilibrium, the differential equation is :

$dF_a /dl = W (F_b \sin a + \cos a)$

Solving for pulling out of hole:

$F_{a2} = F_{a1} + W\,(l_1 - l_2)\,(F_b \sin a_1 + \cos a_1)$ - 15

For running in hole:

$F_{a2} = F_{a1} + W\,(l_1 - l_2)\,(\cos a_1 - F_b \sin a_1)$ - 16

ILLUSTRATION

Planned trajectory of a single build horizontal well is given below,

Kick off point – 3000ft

Build up rate (a_1) – 2/ 100ft

End of build up- 7500ft

Inclination angle (a) - 90°

Total measured depth- 12500ft

Total vertical depth – 5865ft

Specific gravity of mud – 16.8lb/gal

Pseudo friction factor – 0.35

Calculate tensional load on top joint for S-95 (23lb/ft) for interval of 12500 ft

Solution

For 12500 – 7500(ft)

$F_a = F_{a1} + W(f_b \sin a_1 + \cos a_1)(l1\text{-}l2)$

a_1=900, $W = 23\text{lb/ft}\left(1 - \frac{16.8}{65.4}\right) = 17.09\text{lb/ft}$, $F_{a1} = 0$

$F_a = 0 + 17.09\,(5000)(0.35\sin 90 + \cos 90) = 29906\text{lbf}$

Buildup section

For bottom part

$F_a = K_B F_{a1} + \dfrac{WR}{(1 + f_b^2)} [(1- f_b^2)(K_B \sin a_1 - \sin a_2) - 2fb (K_B \cos a_1 - \cos a_2)]$

F_{a1}= 29906lbf, a_2= 60° a_1=90° KB= $e^{-fb(a2-a1)}$ = 1.201;R= 2865ft

$F_{a1} = 1.201 * 29906 + \dfrac{17.09*2865}{(1+0.1225)} [(1-0.1225)(1.201\sin 90 - \sin 60) -$

$0.7(1.201\cos 90° - \cos 60°)] = 64005lbf$

For intermediate part, $F_a = F_{a1} + WR(\sin a_1 - \sin a_2)$

$a_1 = 60°$ $a2 = 30°$ Fal = 64005lbf

F_a = 81924 lbf

For top part

$F_a = K_B F_{a1} + WR [(1- f_b^2)(K_B \sin a_1 - \sin a_2) + 2fb (K_B \cos a_1 - \cos a_2)] /(1+ fb^2)$

= 116,991lbf

Total tension on top joint = **F_{a1} + weight of vertical part**

= 116991 + (3000*0.743*23) = 168258lbf

Thus the total tension on top joint is 168258lbf

5.3 DRILLSTRING/TUBULAR SELECTION[3]

Vertical well drill string design positions drill collars, which provide the Weight on Bit (WOB), immediately above the drill bit based on Lubinski's drill string buckling analysis The buoyed weight of any component multiplied by the cosine of the wellbore inclination provides WOB. Beyond 60° that component decreases rapidly. At 0.1% is available at 85°, while drill string drag rapidly increases. By inverting the drill string whereby the drill collars are in the vertical section of the well bore and the lighter drill pipe is placed at high angles, wellbore drag is reduced while weight can be effectively transmitted to the bit.

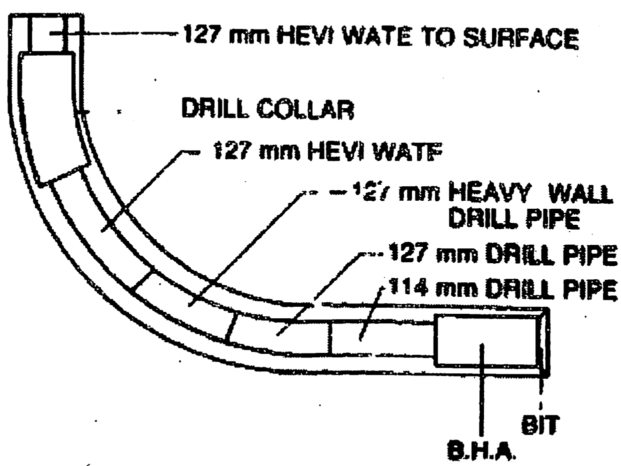


Fig 4: Inverted drillstring design

Drillstring design for the lateral section of the hole can be done by applying the theory of stability in circular rods lying in an inclined hole. This was developed by Paslay and Bogy and applied to drillpipe by Dawson and Paslay.The limits of this model are then compared to drillstring loads calculated using a torque-drag model. The analysis showed that running drillpipe is allowable at high angles. This practice has proven valid in high long-reach drilling.

Paslay –Bogy formulae

The stability of a circular rod in an inclined hole is defined by

$F_{crit} = (4EIApg \sin x/r)^{1/2}$, **where**

F_{crit} = critical load beyond which buckling would occur
E = Young's Modulus (psi)
g = gravitational force
I = moment of inertia (in^4)
r = radial clearance between drillpipe and the hole
A = cross sectional area of the pipe (in^2)
p = density of the pipe (lb/in^3)
x = hole inclination (degree)

The term (pAg) is simply the nominal drillpipe weight in lb/inch and the formula does not include the increased outside diameter at tool joints connections and is a conservative approximation. The radial clearance is the difference between the radius of hole and the radius of the pipe. If the equation is solved for radial clearance between hole and pipe then the maximum hole size can be calculated for a given drill pipe size. The maximum axial load (WOB) is assumed to equal the critical force to initiate the buckling (F_{crit}) and the hole diameter is solved for 0° to 90°.
Using Dawson's methodology, the maximum compressive load, F_{crit}, for a drill string component can be calculated for any hole size or inclination. This is used in constructing tables of maximum compressive loads for each component (fig. 5) . Then, testing the components in various sections of the directional profile for acceptable compressive loading (fig. 5) is possible. An in-house computer program which calculates tension and compression loads based on well profile, drill string design, and theoretical drag values verifies drill string design limits. This same design process and criteria is used to test and confirm the selection of the different casing strings.

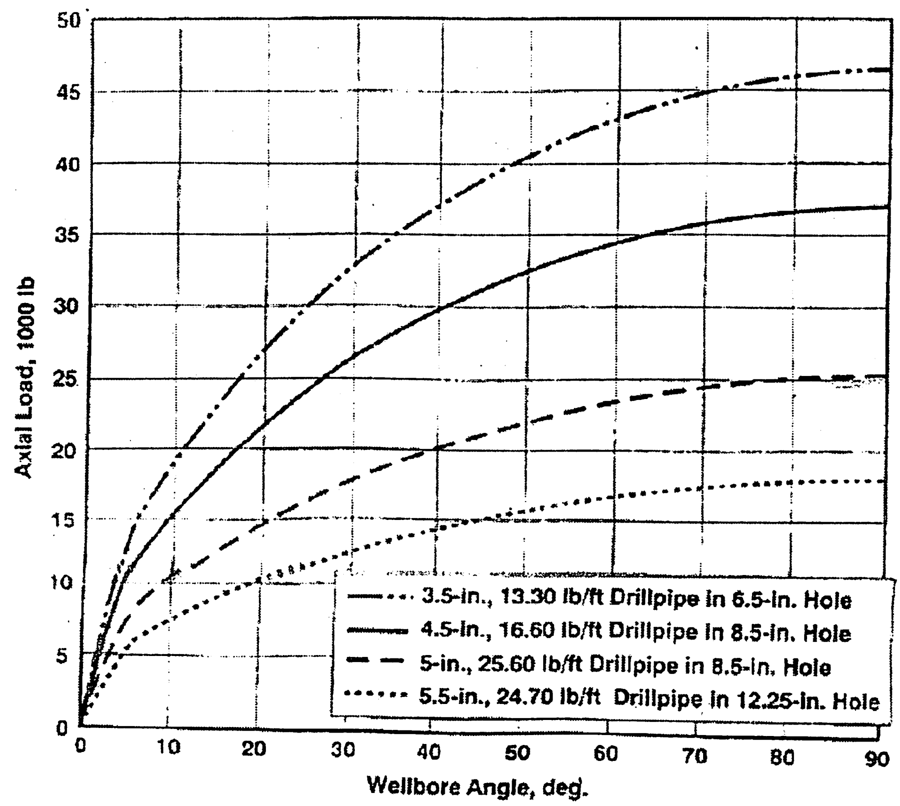


Fig 5: Compressive load capability of drillpipe that increases with hole angle

5.4 BIT SELECTION

When it comes to drilling extended reach and horizontal wells, drill bits are called upon to perform differently than in the case of making a vertical wellbore. Although an extensive body of literature has already been produced on highly deviated drilling, an overview of bit problems encountered at high angles and bit selection criteria is being discussed as below.

PROBLEMS AND CAUSES

The causes of bit problems in high angle wells grow primarily out of either the deviated trajectory of the wellbore itself or out of the methods being employed to deviate the hole to achieve the pay zone.

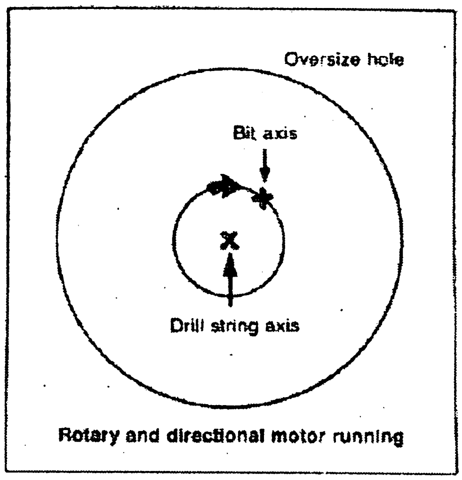


Fig. 1—If the rotary table is used to turn the pipe when a bend assembly is in the hole, the bit will be forced to drill a hole larger than its diameter since the bit will be rotated about the axis of the drillstring.

1. Eccentrically induced sideloading

The single or multiple bends in the assembly cause the bit to drill a hole larger than the diameter of the bit and rotate the axis of the bit in a circle about the axis of the drillstring. The greater the degree of bend or the further the distance of the bit face from the bend, the more this phenomenon comes into play (Fig. 1)

Eccentrically induced side loading can come into play in all sections of an extended reach or horizontal well. This sideloading puts impact stresses on the lower periphery of a rolling cone bit and across the bit face and lower gauge section of a fixed cutter bit (Fig. 2). Reduced bit bearing life and increased gauge wear can result.

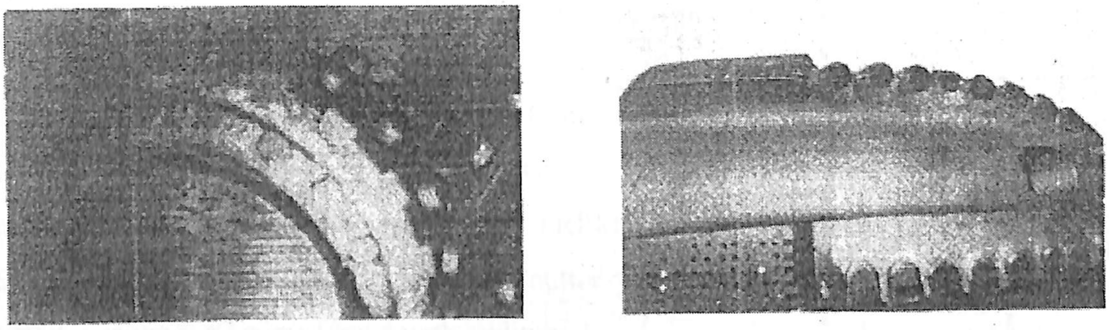


Fig. 2-Sideloading will cause excessive gauge wear on both fixed cutter and rolling cone bits.

2. Another area of concern can result from high bit torque causing motor stalling and toolface orientation problems. When torque limits are exceeded, high pressure builds up in the stalled motor oftentimes resulting in damage to the rubber stator of the motor. High torque can alter the toolface orientation away from its known location resulting in improper and excessive corrections.

At high angles more and more weight is absorbed by the string/borehole interface, potentially providing inadequate WOB, which can cause low rates of penetration for both rolling cone and fixed cutter bits.

3. Azimuth control is another trajectory problem. Even if the build and hold sections are properly made, the target can be missed if bit walk pulls the well path off azimuth. The general rule of thumb is that rolling cone bits walk right and fixed cutter bits walk left. For rolling cone bits, right walk is thought to derive from the bit pivoting on the cone on the low side of the hole and driving the following cone into the right side of the borehole wall. Left hand walk on fixed cutter bits is thought to be purely a result of reactive torque.

4. A final problem associated with high angle wells involves backreaming. Cuttings buildup on the low side of the hole can make coming back out of the hole difficult. The drilled cuttings, especially if abrasive, will attack the shirttail and body of rolling cone bits and accelerate wear on the top of the gauge of fixed cutter bits.

SOLUTIONS

A primary solution lies in selecting or specifying bits with strengthened gauge rows and gauge sections. Increased sideloading and increased RPM add up to accelerated gauge wear. On fixed cutter bits, the gauge can be reinforced with additional natural diamond or thermally stable polycrystalline. Rolling cone bits can be selected that have more durable heel row insert shapes, more gauge inserts and shirttail hardfacing (Fig. 3).Another way the effects of sideloading can be combatted is to select a motor with the bend angle closer to the bit face.

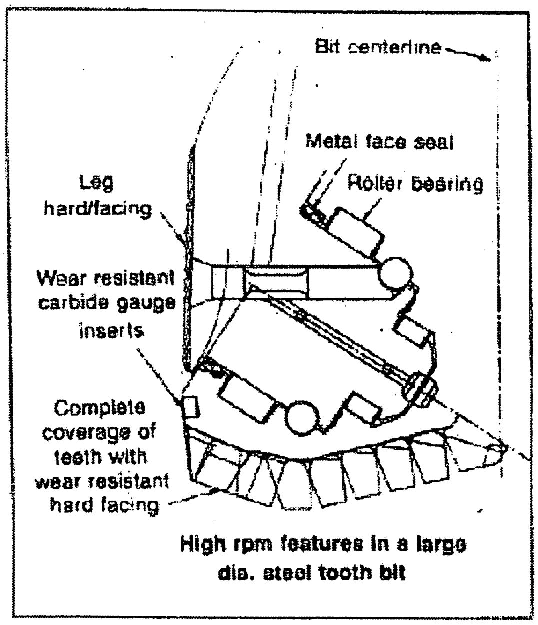
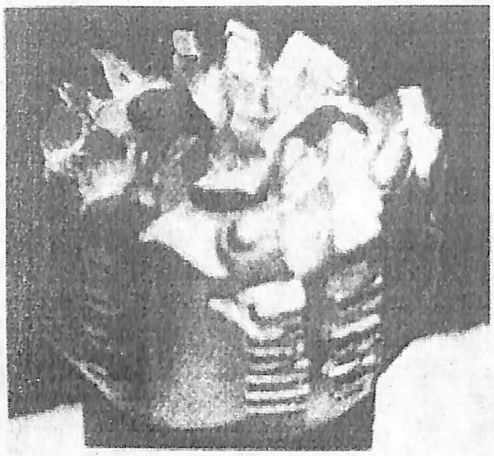


Fig. 3- To combat sideloading wear, rolling cone bits should be s pecified to have more durable heel row insert shapes, more gauge inserts and shirttail hardfacing.

The general problem of reduced bit life due to high RPM can be addressed in a number of ways. Fixed cutter bits have oftentimes been mated to steerable systems because they hold up well to high RPM. When a long motor run is to be executed, a fixed cutter bit may very well be the best selection. Even aggressive PDC bits can be hardened across the face and reinforced up the gauge to wear longer at higher RPM.

Motor stalling and tool face problems essentially only occur when a fixed cutter bit is in use. Selecting a less aggressive fixed cutter bit that produces less torque may improve or solve the problem. Switching out to a rolling cone bit will certainly solve this pair of problems.

On fixed cutter bits the basic controlling factors on steerability are gauge length and side cutting aggressiveness. Fixed cutter bits with long gauge pads can be difficult to steer, so shorter gauge lengths (Fig. 4) could be advisable if steering rate is critical. In addition custom designs with aggressive sidecutting structures, such as PDC pads, can greatly increase steerability.



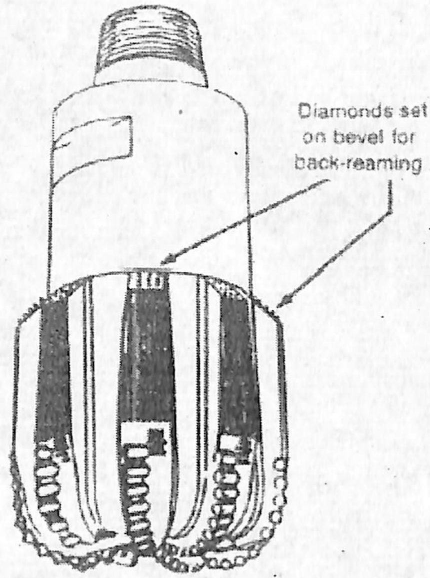


Fig. 4-Shorter gauge lengths used on fixed cutter bits make them easier to steer. Aggressive sidecutting structures also increase steerability. Fig 5: Use of diamonds on the bevel of a fixed cutter bit allows it to be used for backreaming when cuttings buildup is a problem

For azimuth control two solutions are available. By continuing to use the steerable system, RPM can be substituted for weight to regain adequate penetration. The other option, for either a motor or rotary run, is to select a more aggressive bit, fixed cutter or rolling cone, to make better use of the weight available at the bit. Where the bit is concerned, the problem of cuttings buildup on the low side of the horizontal section can become evident when the bit is to be tripped out of the hole. On rolling cone bits, leg pads will help lift the bit out of the cuttings and provide additional bit body protection. Shirttail hardfacing will also improve the wear resistance of the sides of the bit.

Increasing the gauge diamond setting on a fixed cutter bit and wrapping the setting around the top of the gauge onto the bevel (Fig. 5) will help to maintain the gauge of the bit and provide a reverse cutting structure for backreaming. These features also will improve the likelihood of pulling a rerunable bit. A final approach to the problem of developing a cuttings bed at the bottom of the horizontal section is to employ a fast-gelling drilling fluid that holds the cutting in suspension, avoiding low side buildup.

5.5 DRILLING FLUIDS[19]

Introduction

Drilling long radius horizontal wells and extended reach wells involves some critical issues that can pose significant challenges for the operator. From the drilling fluids perspective, these include:

- . Narrow Mud Weight/Fracture Gradient Window
- . ECD Management
- . Hole cleaning
- . Torque and Drag
- . Borehole stability
- . Lost Circulation
- . Barite Sag

The drilling fluid is a key success factor in drilling and, historically, oil or synthetic base muds have tended to be the fluids of choice. However, in the current era of increasingly stringent environmental constraints, the industry is striving to expand the fluids technology envelope with the development of more inhibitive water-based mud systems, in .conjunction with suitable lubricants, to replace invert emulsion muds.

Drilling fluids for ERD wells are engineered to provide a flatter rheological profile in order to minimise the effect of the fluid rheology on ECD. Experience on some of these operations has led to the development of many torque and drag reducing products and techniques. Unique downhole hydraulics and hole cleaning modeling software has been used in conjunction with down-hole pressure while drilling (PWD) tools to accurately plan and predict fluid hydraulics and cuttings transport to great effect on the world's longest wells.

Drilling Fluids For Horizontal Wells

For good hole cleaning, vertical flow is advantageous because cuttings fall in a direction opposite that of the drilling-mud flow. For an inclined well, the direction of cuttings settling is still vertical, but the fluid velocity has a reduced vertical component. This decreases the mud's capability to suspend drilled cuttings and results in faster particle settling velocities at greater hole inclinations. Particle trajectory (influenced by axial fluid movement-and downward particle movement) is such that particles that slip through the fluid have little distance to travel before striking the borehole wall.

Local fluid velocities near the well are small, which reduces further particle movement. Particle dwell time is increased in the annular space, hence increasing the net volume of cuttings in the wellbore. For near-horizontal wells, particle dwell times usually are long enough to allow formation of contiguous cuttings beds. Fig. 1 illustrates cuttings behavior in inclined holes.

Cuttings beds impede drillpipe movement into or out of a wellbore, and often the drillpipe gets stuck. In any event, cuttings beds increase nondrilling rig time and costs. This hole-cleaning research identified how drilling parameters affect cuttings accumulation and bed formation so that controllable parameters may be adjusted for minimal cuttings buildup.

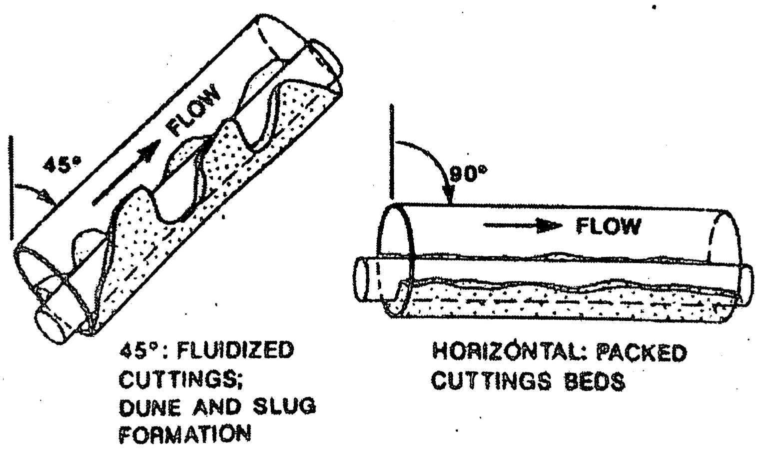


Fig 1: Cuttings behaviour in inclined and horizontal annuli

Effect of Hole Angle, Drill cuttings are carried to the surface of an inclined well partially by the vertical component of annular mud velocity. Because this component decreases as the hole angle approaches horizontal, the cuttings-removal rate may decrease. Thus, formation of a cuttings bed is more likely at higher angles from vertical.

Main Effects of Individual Variables. Annular mud velocity, mud weight, hole angle, and drillpipe rotary speed all have significant effects on the cuttings bed area. Smaller cuttings beds occur for higher mud velocities, mud weights, and rotary speeds, and usually for lower hole angles (from vertical). Of these four variables, mud velocity has the strongest effect and hole angle has the weakest effect on bed cross-sectional area. Drillpipe eccentricity and mud rheology usually do not significantly affect cuttings-bed size.

Two-Factor Interactions. The degree of bed reduction when increasing mud velocity depends on other variables. Figs. 4 show better hole-cleaning performance at higher mud velocities, rotary speeds, and mud weights; at hole angles closer to 60° than 90°; for muds with lower rheological property values;. and for oil based instead of water-based muds. Fig. 4 compares the effects of rotary speed, hole angle, and mud type at specific mud velocities.

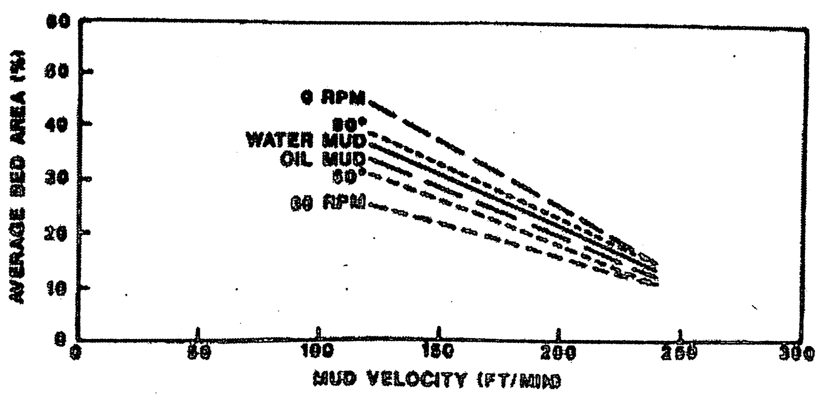


Fig 4: Effect of velocity on bed area for various rotary speeds, hole angles, and mud types

Effects of rotary speed and hole angle diminishes with increasing velocity.. A two-factor interaction occurs when the effects of one variable are influenced by another variable. Fig. 4 indicates that the effect of drillpipe rotary speed is diminished by increasing mud velocity, while Fig. 5 shows that mud velocity's effect is not affected by mud weight variations. These illustrate the interaction between drillpipe rotary speed and mud velocity, and the non-interaction between mud weight and mud velocity. Effects of rotary speed are compared at each velocity level (Fig. 7).. (The tangential component of mud velocity induced by drillpipe rotation may be more significant at lower annular mud velocities.) Drillpipe rotation often affects the role of mud rheology and velocity in bed formation.

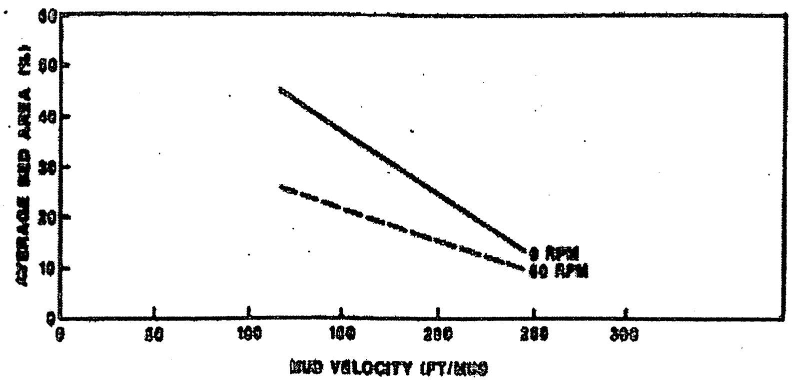


Fig 7: Effect of velocity on bed area for two drillpipe rotary speeds

Many interactions occur among drilling variables during efforts to clean a borehole. Table 6 summarizes the general importance of the various factors. To decrease the size of cuttings beds, increase mud weight, annular velocity, and drillpipe rotation .

Usually it is less effective to change mud rheology or mud type, and the driller usually has little control over drillpipe eccentricity. Cutting beds could be quite substantial (especially with the drillpipe on the bottom of the hole) and could result in stuck pipe. Also, cuttings slide more in oil-based muds than water-based muds. Smaller cuttings beds reduce incidents of lost circulation and stuck pipe, both of which result from packing off caused by large beds. Now three mud pumps are often used instead of two. The use of top-drive rigs now allows the drillpipe to be rotated while tripping. This also has reduced hole-cleaning problems.

Table 6: Summary of effects and factors

Effects	Factors
Major	Mud weight
	Annular mud velocity
	Hole angle
	Drillpipe rotation
Moderate	Rheology
	Cuttings size
	Eccentricity
Minor/insignificant	Feed concentration (ROP)
	Mud type
	Drillpipe size

Fluid Selection[19]

Invert emulsion muds have been the key ingredient in successful long reach drilling developments in many areas of the world, e.g. Wytch Farm, Argentina and the Gulf of Mexico. This is the direct result of their ability to provide high lubricity, stabilize reactive clays, preserve hole stability, resist contamination and produce firm, dry cuttings. Torque and drag readings and the potential for differential sticking are substantially lower, using an invert system, with an enhanced ability to slide and less tendency for cuttings bed compaction. All these factors combine to make invert emulsion muds the fluids of choice for extended reach wells. Invert emulsion muds, based on mineral or synthetic base fluids with low kinematic viscosity, are well proven in the field and provide a low ECD, excellent hole cleaning and cuttings suspension and extremely stable mud properties.

The most suitable water-base fluids currently available for ERD drilling, when shale inhibition is required, are potassium based, non-dispersed, polymer muds containing glycol or silicates. When inhibition is not required, low solids polymer formulations or mixed metal silicates may be used. These systems provide the required hole cleaning and their use, with a suitable lubricant is highly effective.

Current inhibitive water-based mud systems containing glycols, etc., while achieving excellent results do not match the performance of oil or synthetic base muds. They produce aqueous filtrates that can result in the onset of timedependent hole instability effects over an extended drilling period. This increases the potential for packing off and mechanically stuck pipe. However, these problems occur to a much lesser degree with silicate muds.

Silicate drilling fluids exhibit remarkable shale stabilising properties, resulting in gauge hole and the formation of firm, discrete cuttings when drilling reactive shales. Silicate muds are now replacing inverts in certain applications. Silicate muds are low solids polymer systems formulated in seawater or monovalent brines with the addition of a soluble silicate complex for inhibition. The mechanism of inhibition is due principally to a precipitation reaction, which occurs on contact with divalent ions present at the surface of the shale, rapidly sealing or partially sealing the pore spaces. A silicate skin or pressure barrier forms which allows mud hydrostatic pressure to support the borehole wall in a similar manner to an invert emulsion mud. The transmission of mud pressure to the shale and time-dependent increase in near-wellbore pore pressure are thus significantly reduced compared with conventional water-based muds. Where the required mud weight is not a constraint, mud salinity can be raised to control osmotic pressure and further restrict water migration.

Glycol-enhanced water-based mud systems offer the advantages of enhanced shale inhibition, improved filter cake quality, reduced fluid loss and reduced dilution rates. Shale destabilization, leading to borehole breakout, is reduced when using a glycol enhanced mud. Glycol solubility with temperature can be adjusted by altering the glycol concentration or the salinity of the mud system. As the temperature of the mud system increases, under conditions of constant salinity and. glycol concentration, a micro-emulsion begins to form in the water phase above the cloud point. Eventually, the glycol is completely 'clouded-out' and is totally immiscible. Research and field experience suggests that maximum inhibition is provided by the glycol within this temperature window. For most glycols to be effective, an inhibiting ion (preferably potassium) needs to be present. In environmentally sensitive areas, the use of potassium acetate or potassium formate is preferred to potassium chloride.

ECD Management

The increasing length of the annulus and the associated increase in annular pressure loss (APL) with depth, for a given circulation rate, is not matched by an equivalent increase in formation strength. This reduces the mud weight/fracture gradient window and can limit pump rate to the extent that achieving adequate solids transport can be difficult, particularly in enlarged hole sections. An invert emulsion drilling fluid is ideally built around a base fluid having a low kinematic viscosity, coupled with effective emulsifier and fluid loss additives and top grade organophilic clay. Specialised organoclays have been developed as suspending agents to enhance yield stress while avoiding significant impact on plastic viscosity. A base fluid with a low kinematic viscosity will aid in achieving a flatter rheological profile, enhancing hole cleaning in large diameter hole sections while contributing to lower ECD.

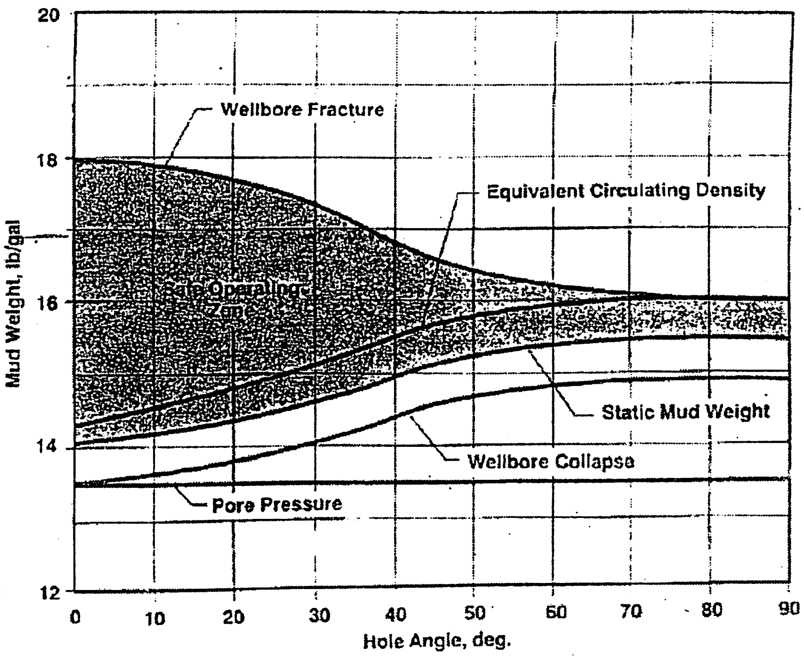


Fig 8: Safe drilling-fluid weight range decreases as hole angle increases

Rig Capabilities

In addition to geological, geometric, hydraulic, and mechanical considerations, directional planning must also consider the capabilities of the rig and associated drilling equipment. The "severity" of the well being planned can be limited by a number of rig aspects, (he term "severity" refers to-a qualitative measure of the extent of doglegs, turns, angle, reach, depth, and other factors that influence hoisting, torsional, and hydraulic capabilities of the drilling rig.) Hoisting capability may impose directional limitations on the well, depending on the TVD of the target, the amount of frictional drag associated with lifting the drillstring or deep casing strings, and the amount of mechanical drag induced by doglegs, keyseats, etc. In severe directional wells, torque demands may exceed the capacity of the rotary table, top-drive system, or drillstring members. These issues should be evaluated through the use of torque-and-drag models before the rig is specified. Top drives are becoming standard equipment on rigs for drilling directional wells. The ability to circulate and rotate while tripping is an absolute necessity in some directional wells, and always a welcomed capability in others. Accurate torque sensing is necessary because of the higher torque demands of directional wells. Because inclined wells require higher flow rates to clean the cuttings from the well, the pressure and/or flow rate capacity of the pumps and surface plumbing should be evaluated. The rig must generate enough power to run the pumps, the rotary or top drive, and the draw-works simultaneously at elevated operating parameters. Simlilarly, the rig's solids-control system must have a volumetric capacity that matches the flow rate requirements, or elevated flow rates will not be sustainable. Because of the various interrelationships between drilling mechanics and the directional trajectory, an integrated and comprehensive approach to rig selection must be taken during the planning and evaluation of highly deviated wells.

6. Horizontal Well Completions

6.1 Cementing Problems

Problems associated with cementing liners in high-angle and horizontal wells are briefly summarized as given below

- Mud circulation: Proper circulation at the highest allowable pump rate is necessary to break the gel strength of the mud, and facilitate its removal by the displacing fluids.

- Centralization: Casing centralization is difficult when the angle of deviation is high, because of the increasing load on the centralizers. To maintain optimum standoff, a rule of thumb is to keep the spacing between the centralizers below 20 ft (6.1 m). Rigid bar centralizers, are recommended when cementing in near-gauge hole. The centralizers should include a bearing sleeve which allows the pipe to be rotated and reciprocated without moving the centralizers. The required number and positioning of centralizers can accurately be determined by computer simulation

- Cement must effectively displace mud in an irregular, eccentric annulus.

- Slurry stability: There are two properties that determine the stability of the slurry - free water and sedimentation. Free water should be maintained at zero. In the laboratory, the free water and settling should be measured at the anticipated maximum angle of deviation.

- Simultaneous rotation and reciprocation: Movement of the casing or liner is important to aid in breaking the gel strength of the mud, and to allow the displacing fluids to sweep away the mud. Both rotation and reciprocation are preferred over either method alone. Rotation is preferred in gauge holes because the rotational forces on the fluid will cause it to be swept entirely around the annulus. Reciprocation is an acceptable alternative, and should be used in washed out holes. Rotation should be at 10 to 20 RPM, and reciprocation should be in lo- to 20-ft (3- to 6-m) strokes, with one to two strokes every one to two minutes.

- Fluid-loss control is particularly important in horizontal wells, because slurry exposure to long, permeable sections is more extensive than in vertical wells. The fluid-loss rate should always be less than 50 mL/30 min. One method to obtain very low fluid-loss rates without adversely affecting free water and viscosity is to use a properly designed, latex-modified cement system.

6.2 Well Completion[15,16]

Initially horizontal wells were completed with uncemented slotted liner unless the formation was strong enough for an openhole completion. Both methods make it difficult to determine producing zones and if problems develop, practically impossible to treat the right zone. This need has arisen because reservoirs are horizontally heterogenous.Zonal isolation is thus required to tap several producing formation in natural fracture systems or through faults. Zonal isolation is achieved using either External Casing Packer (they have mostly been replaced by swell packers these days) on slotted or perforated liner or by conventional cementing and perforating.

The various lateral section completion offers varying degrees of efficiency for the ability to manage the reservoir. Some of these are basic, while others are complex. The selected completion method must be designed to fit the production constraints and the reservoir characteristics. The completion options also depend on the degree of rock consolidation, on the need for water or gas shut off, the anticipated flow rate, the completion longevity, the shale reactivity and the stability, the degree of grain sorting and the lamination. The wellbore stabilization is of a primary concern. For laminated formations, a gravel pack stresses the formation and immobilizes fines. For a non laminated formation with well sorted grains, a non gravel pack completion is generaly considered adequate, unless completion longevity is required, or the well is producing at a high flow rate. The recent advances allow the following options for lateral completions of consolidated formations:

- Open hole
- Pre-drilled or slotted liner
- Pre-drilled or slotted liner with external casing packers
- Casing or liner, cemented and perforated
- Open hole with the pre-drilled liner and the stand alone screen
- Open hole with the stand alone screen
- Open hole with the gravel pack

Open hole

In general, barefoot horizontal completions are implemented only in very competent, hard formations that pose little risk for wellbore collapse and/or sand production, such as dolomites, hard limestones, hard sandstones, and shale-free siltstones As a rule of thumb it is only applied to formations having unconfined compressive strength (UCS) greater than 10000psi.

When the reservoir contains numerous significant or complex fluid contacts openhole completions become increasingly risky. The production engineer should carefully investigate the mobility of the various reservoir fluids in the context of in-situ fluid contacts and must consider any potential barriers or conduits to fluid movement. Connecting highly mobile extraneous fluids (water or gas) through highly permeable conduits to a horizontal well will result in significant unwanted production. Operators also avoid using openhole horizontal well completions in reservoir exhibiting highly fractured, vugular dominated porosity, or facies with significant permeability contrasts.

Pre-drilled or slotted liner

The slotted liner (Fig. 6) is generally used when there is a doubt about the wellbore stability, or when there is some concern about the sand production. The slotted or perforated liners are those where the liner is run in the open hole and hung off in the production casing. In addition, if reactive shales have been encountered in the formation, a liner may be the adequate alternative to prevent the hole sloughing and wellbore collapse. In well consolidated formations, pre-drilled liners are generally used instead of the slotted liner. The slotted and pre-perforated liner completions are considered only when a little or no stimulation is anticipated and there is no concern for excluding unwanted fluids such as water or gas.

Pre-drilled or slotted liner with external casing packers

The external casing packers are normally used to provide an effective annular seal between zones of varying fluid types or pressures in uncemented open hole completions. This completion method (Fig. 7) is an improvement of the liner completion when the zone isolation is required. External casing packers are run as an integral part of the liner and after inflation they seal against the inner diameter of the borehole. They can be inflated with water, mud or cement. When properly inflated, they can provide a positive seal for the selective production, stimulation or other injection purposes. The external casing packers are used in conjunction with slotted liners, screens, pre-packed screens or liner and sliding sleeves. These days they are being replaced by swell packers which are most recommended for zonal isolation these days.

Casing or liner, cemented and perforated

The cased hole completions (Fig. 8) are defined as a liner or casing being cemented in place with perforations shut in the production intervals. Compared to the other completion methods, the cased hole completion provides a highest degree of the wellbore control and the reservoir management. Because of the possibility of cement invasion in naturally fractured formations, the cased hole completion method has primarily been used in non naturally fractured reservoirs. Cased hole completions are excellent for reservoirs where the horizontal well is being drilled to minimize coning problems. Perforations may be selectively squeezed off to prevent the influx of unwanted fluids.

Open hole with the pre-drilled liner and the stand alone screen

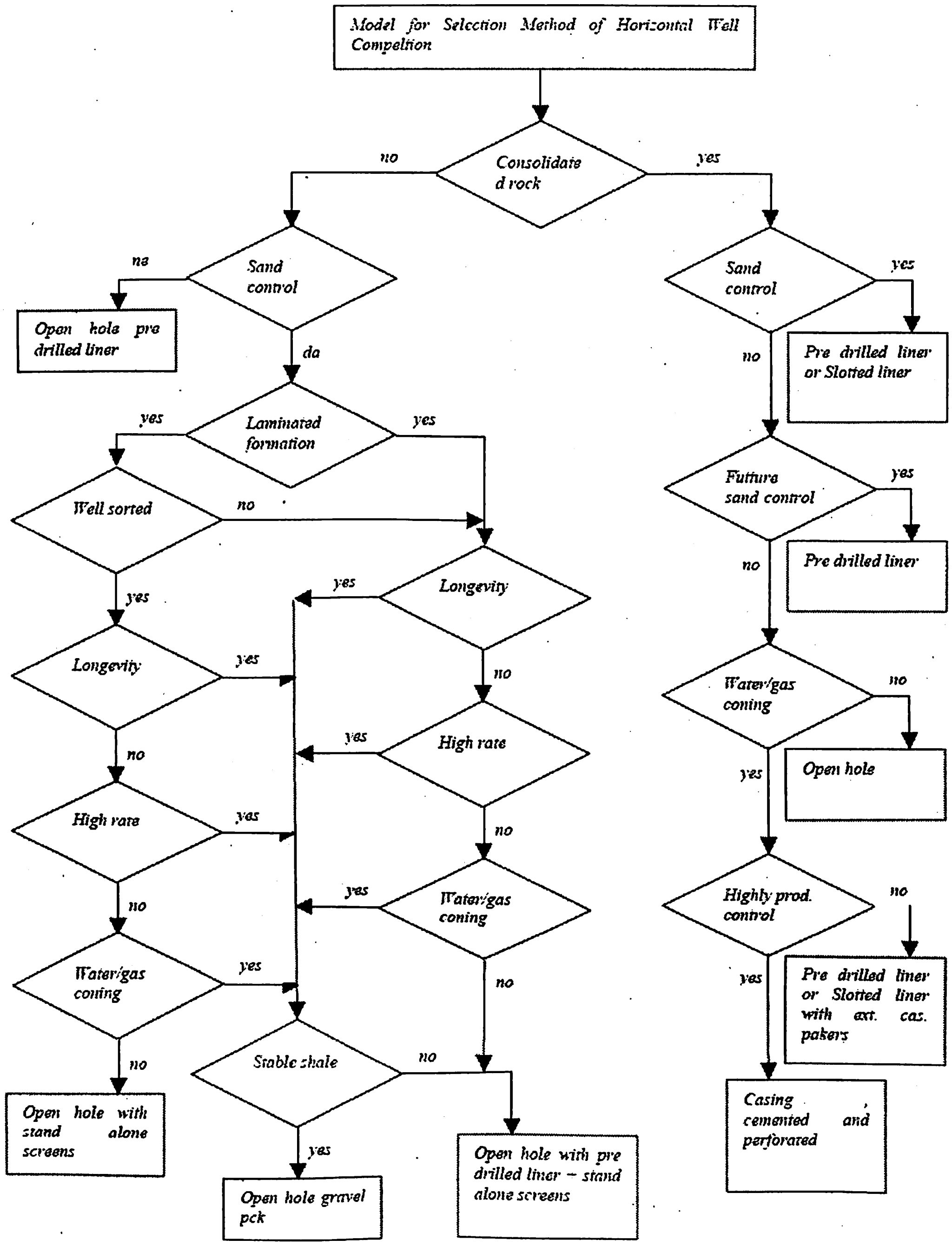
An open hole completion with the stand alone screen (Fig. 9) is generally used in unconsolidated formations where the sand control presents a problem. The screens are used without a gravel packing to exclude the entry of formation sand into the flow stream. The completion can be executed with external casing packers to isolate unwanted fluids, if this situation exists. Stand alone screens can be either pre packed or all metallic. The pre packed screens are actually modular gravel packs because they have a resin coated gravel or a loose sand packed around them to prevent a formation of sand passage. Pre packed screens are considered suitable for the use in horizontal wells without a gravel pack. However, the reservoir should be relatively clean, while the formation sand needs to be quite uniform, preferably not fine grained and with average volumetric flow rates.

Open hole with the stand alone screen [14]

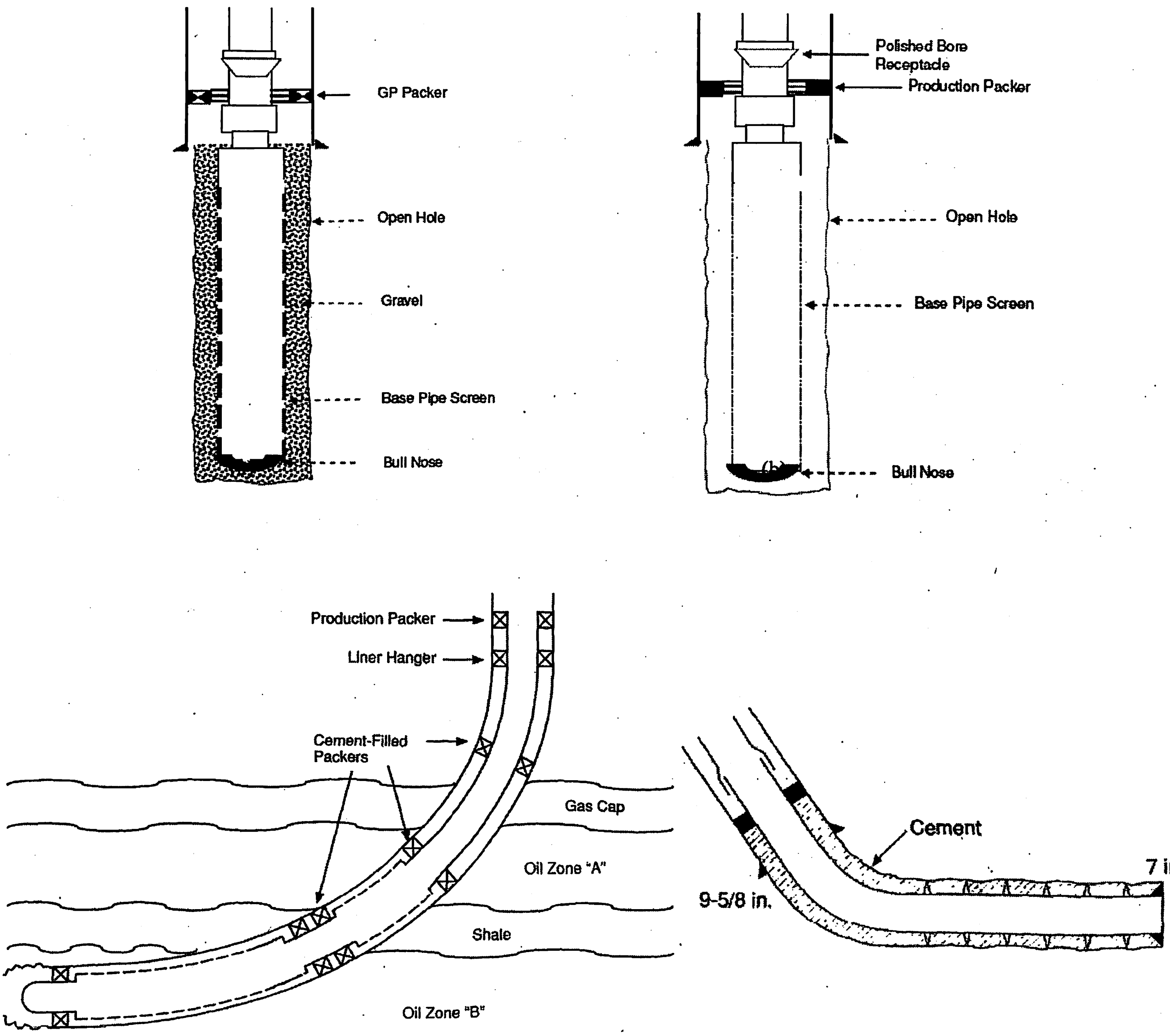
An open hole completion with the stand alone screen enhances the placement of the screen because it is run inside the pre-perforated liner. This technique (Fig. 10) is used primarily in unconsolidated rock, requiring sand control for which difficulties are experienced with running the screens by themselves because of well instability due to reactive shales.

Open hole with gravel pack

The open hole gravel packs consist of performing a horizontal gravel pack across the open hole interval. Advantages of this approach are the productivity maintenance and the completion longevity when compared to the stand alone screen completions. The main requirement for a successful horizontal gravel pack is a clean, stable, and undamaged well prior to running the gravel pack screen. The presence of reactive shales which swell or slough into the hole before or during the gravel packing operation is a major difficulty of the open hole gravel packing. An unstable, dirty wellbore contaminates the gravel, causing a poor well productivity.



Flowchart for selection of horizontal well completion



(c) (d)

Illustration of some of the horizontal completions(a)Open hole gravel pack(b)Open hole with stand alone screen(c)slotted liner with ECP's(d)cemented and perforated liner

6.3 PERFORATION[3,14]

While drilling horizontal well sections to maximize production has evolved into a routine practice, perforating horizontal sections still presents completion challenges. Attempting to maintain wellbore and perforation tunnel stability by perforating in the direction of maximum stress compounds the complexity of the perforating job. Ensuring that orientation remains valid while navigating through severe doglegs requires detailed pre-job design planning supported by applicable research data. Completion and perforation techniques in horizontal wells have continued to advance through shared experience and new technology developed together by various oil services companies.

From a geomechanical standpoint, the stress directions of the formation must be considered. To maintain wellbore and perforation tunnel

in the direction of the maximum formation stress.

This objective poses the first challenge of how to provide perforation orientation in a horizontal or highly deviated section. The perforating guns shaped charges need to be shot in directions that will subject the perforation tunnel to the least amount of collapse stress

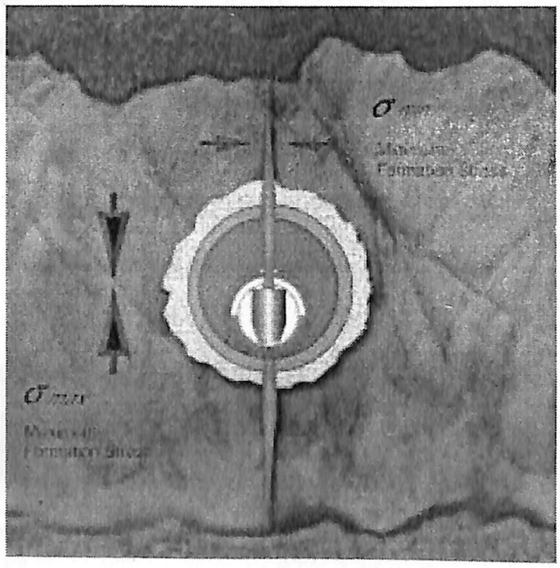


Fig 1: Orientation of shots based on formation stresses.

The reservoir's mechanical properties need to be analyzed from petrophysical data, and the well must be identified as a viable candidate before designing the perforating program.

Formation stresses can be derived from digital acoustic and density log data computed to obtain the mechanical properties of the reservoir. The results of the Mechanical Properties log may indicate that oriented perforating may not be practical if the formation is extremely weak or unconsolidated, as the stresses may be approaching an isotropic condition with little contrast between the stress magnitudes.

The Mechanical Properties log also can predict the critical drawdown pressure (CDP) at which sand production can be expected.CDP is the difference between the average reservoir pressure and the bottomhole flowing pressure above which mobilization of unconsolidated and/or disaggregated sand grains broken by perforation and concentrated stress around the borehole is expected to occur.

The CDP must be considered for the entire life of the field to avoid sand production and prolong the longevity of the field wells. When reservoir pressure declines, both the net vertical stress and net horizontal stress increase in such a way that the formation shear stresses are increased. If the shear stress increases to the point that the formation generally fails in shear, then weakly cemented rock may become disaggregated, thus leading to a low value of unit cohesive strength. The allowable drawdown for perforation stability may then be very low. For this reason, the stress state of the reservoir must be checked to determine whether the stresses will be below the failure envelope throughout the life of the field. The change in stress due to depletion depends on reservoir depth, areal extent, thickness, and elastic properties of the reservoir and bounding formations.

The job can not be considered a success unless this is verification that the guns actually fired in the desired orientation. This poses yet another challenge on how to prove that the shots were indeed fired in the desired orientation.

Several other mechanical concerns such as torque and drag issues, which will determine the ability to convey the guns downhole especially in severe doglegs, further complicate the procedure. Torque and Drag modeling software must first be used to evaluate candidate guns, well paths, and buckling limits.

In addition, a well modeling software analysis to forecast performance needs to be performed to compare perforating options and determine the best perforation design to optimize production. Reservoir characteristics also determine optimum shot placement. A thorough formation evaluation is recommended to ensure thinly laminated beds are allowed to contribute to the total production.

Techniques for gun orientation

In consolidated formations full size guns with complete phasing are recommended. In consolidated formations. The perforations are normally limited to the lower 180°or 120° of the well .This is to avoid sloughing of the hole during production.

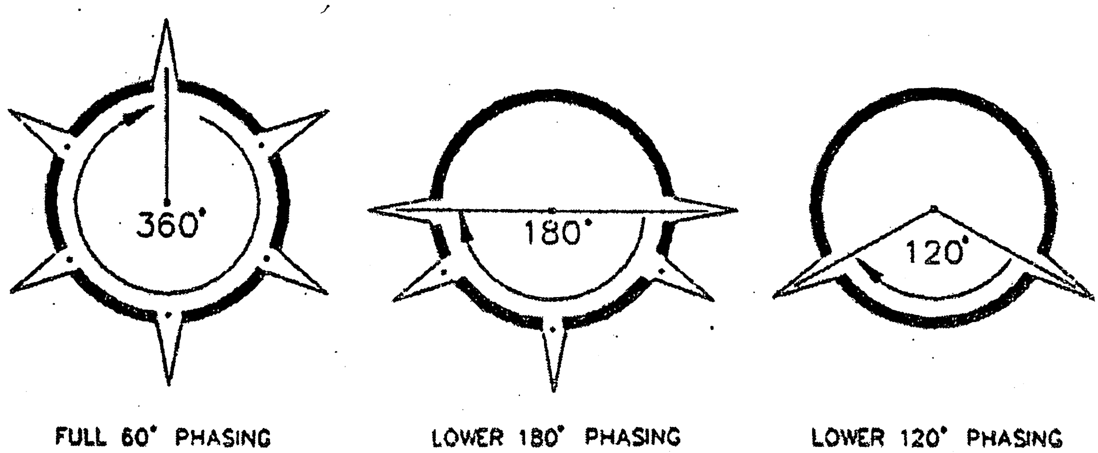
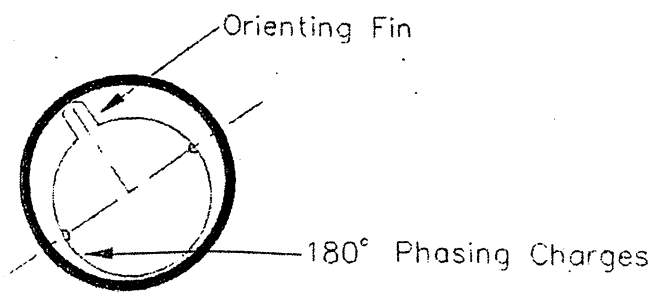


Fig 2: Perforation configuration in consolidated (360°) and unconsolidated formations

When perforating the low side of the well, the entire gun section must be oriented. Steering tools and other methods can be used to orient the top of the gun. However with the length of the perforating assembly is normally limited to 150 ft.A commonly used method to overcome misorientation employs swivel subs and orienting fins. The fins are welded to the top of the top side of the gun, lowering the gun's center of gravity as shown in the figure.



(c)

Fig: (a) Orienting fin used to prevent "spiraling "of long guns during running and positioning

Both the perforation entry hole size and depth of the perforations are affected by gun clearance or standoff. In consolidated formations the largest gun that can be run and retrieved leaving room for gun swell and surge solids should be used .In unconsolidated formations the risk of surging significant sand into the casing requires that both the degree of underbalance and gunsize be reduced .The gun size must be small enough to be washed over if it becomes stuck.

Gun conveyance methods

Perforating guns can be run in two different ways :

- Tubing conveyed with or without packer
- Coiled tubing conveyed

Tubing conveyed perforated guns

TCP in a horizontal well is similar to that in a vertical well. Perforating can be carried out in an underbalanced state or overbalanced wellbore, with or without a packer. In horizontal wells hydraulic pressure is used to actuate the perforating guns. hydraulic pressure actuation presents a problem, if underbalanced condition is required during perforating.

When a packer is run, an underbalance can be created by using a crossover or a hydraulic bypassing the packer .The guns are detonated by applying pressure to the annulus as shown. The tubing in this arrangement is run with a precalculated fluid column to create the underbalance .Annular pressure is applied to the firing head via the crossover at the packer.

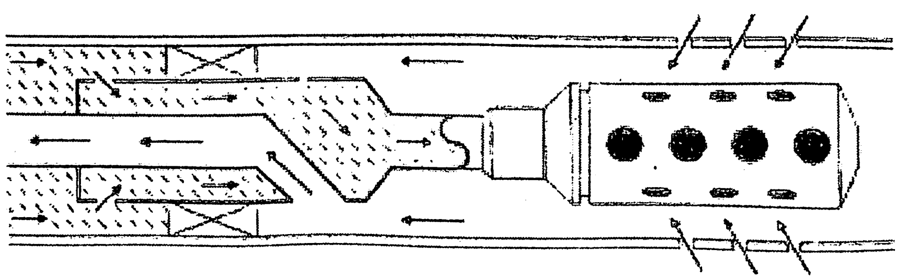


Fig 3: Diagram of crossover used to transmit annular pressure to activate pressure-sensitive detonators on TCP guns while maintaining under-balance on the formation

If a packer is not run ,the guns can still be hydraulically actuated while maintaining an underbalance by using a bypass assembly with a check valve in the pump seat of the bypass assembly .Nitrogen is injected into the tubing/casing annulus which displaces the annular fluid into the tubing .The nitrogen in the annulus is then bled off to creatre the desired underbalance.

Coiled Tubing perforating

Coiled tubing with a conductive cable threaded through it can be used for both logging and perforating. Coiled tubing can be used to perforate multiple intervals using short switched guns .However its limitations are quickly reached when longer guns are run. Coiled tubing will buckle when frictional forces associated with the guns in the horizontal hole exceed the coiled tubing critical buckling load.

The advantages of coiled tubing are the speed of running the guns, the ability to log perforating guns on depth and the ability to make multiple runs.

7. Horizontal Wells-Reservoir Aspects

Deliverability of wells is the main focus of petroleum industry anywhere in the world. Advances in science and technology applied to drilling and production engineering resulted in a modern well design, ability to drill and complete a well with complicated trajectory in order to reach a certain part of the reservoir. As most of the oil and gas reserves are much more extensive in their horizontal dimensions than in their vertical (thickness) dimensions, the concept of horizontal drilling technology came into existence. Advances in computer hardware and software development triggered a new approach to the reservoir enabling a more detailed and better quality analysis and selection of the drainage strategy and field development concept. Multilateral wells are the part of advanced horizontal drilling technology. The first multilateral well was drilled in Russia in 1950's. Europe's first multi-lateral wells were completed by Elf Aquitaine in 1984 in the Paris Basin, France. Norsk Hydro completed successfully the first ever Level 5 multilateral well in the Oseburg Field, North Sea during 1996. In USA, Shell successfully completed its first Level 6 multilateral well during 1998.

7.1 RESERVOIR ENGINEERING CONCEPTS

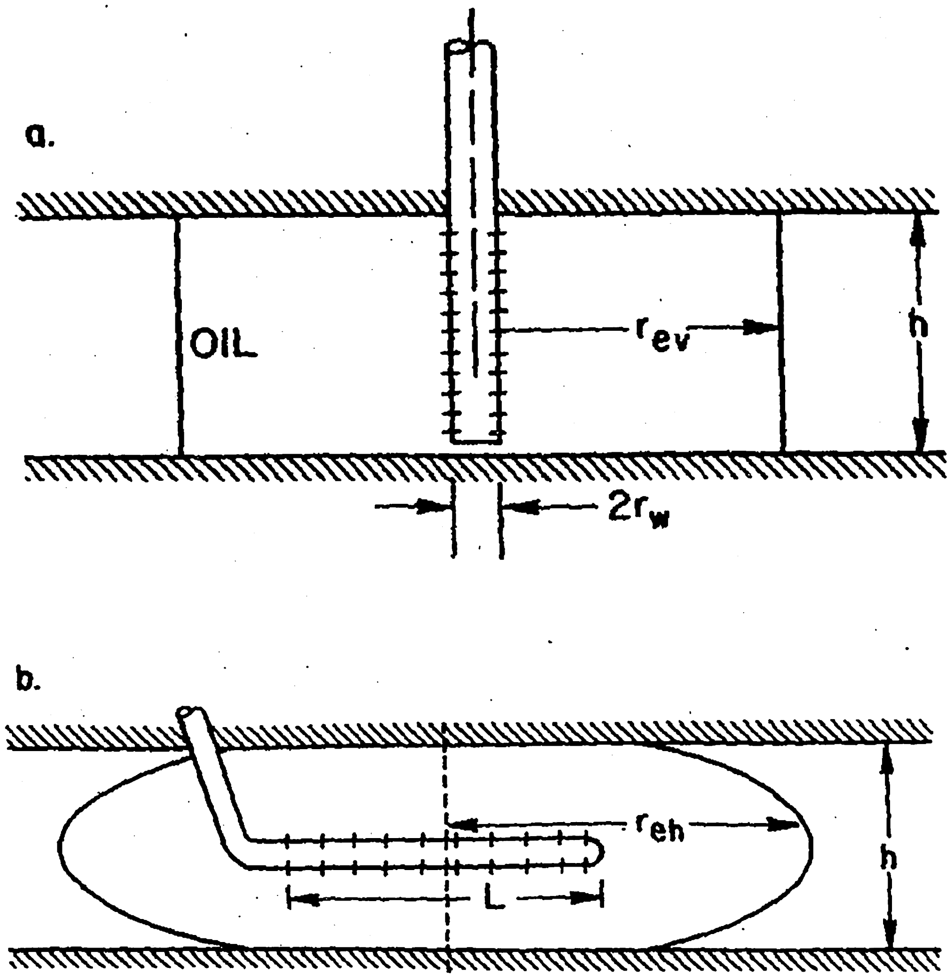


Fig. 7.1. A Schematic Of Horizontal & Vertical Well Drainage Areas

The above illustration/figure shows a drainage area for a vertical well and a horizontal well. A vertical well drains a cylindrical volume, whereas a horizontal well drains an ellipsoid, a three-dimensional ellipse. In general, we expect a horizontal well to drain a larger reservoir volume than a vertical well.

Figure 2 shows a fractured vertical well. The well is drilled in the reservoir of height h. The well is fractured and the fracture is fully penetrating, i.e., it covers the entire reservoir height. The fracture half-length is equal to x_f. Moreover, we assume that the

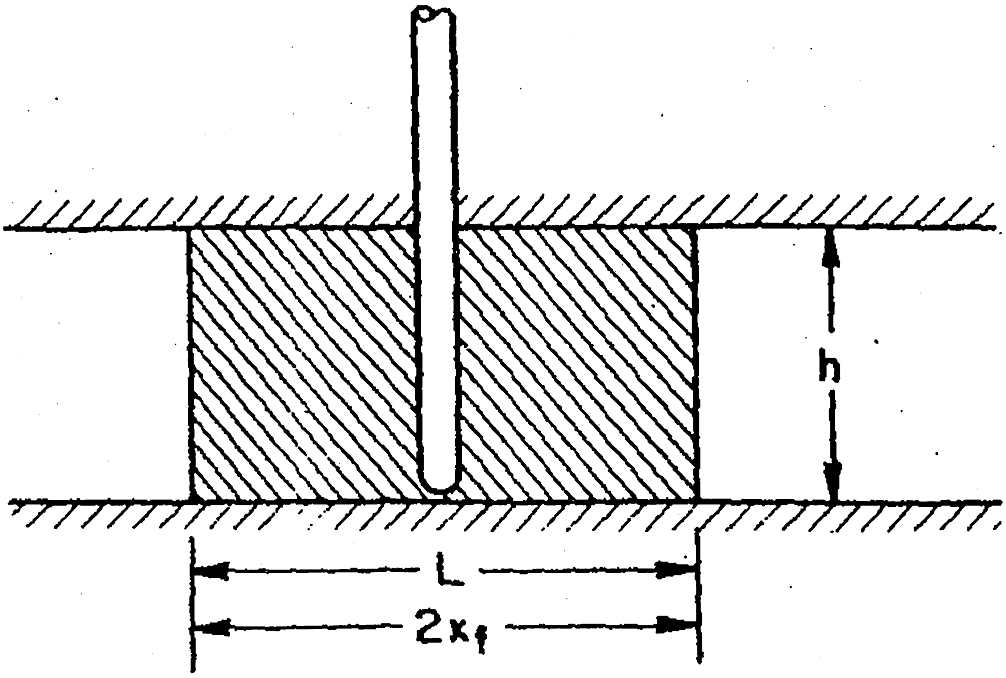


Fig. 7.2. A Schematic Of a Fractured Vertical Well

fracture has art infinite conductivity, which means that pressure drop within the fracture is negligible.

In other words, pressure in the vertical wellbore and at every point within the fracture is the same. This represents an ideal or desired fracture for a vertical well, If the height of this fracture is reduced, one would obtain a horizontal well (Fig. 3).

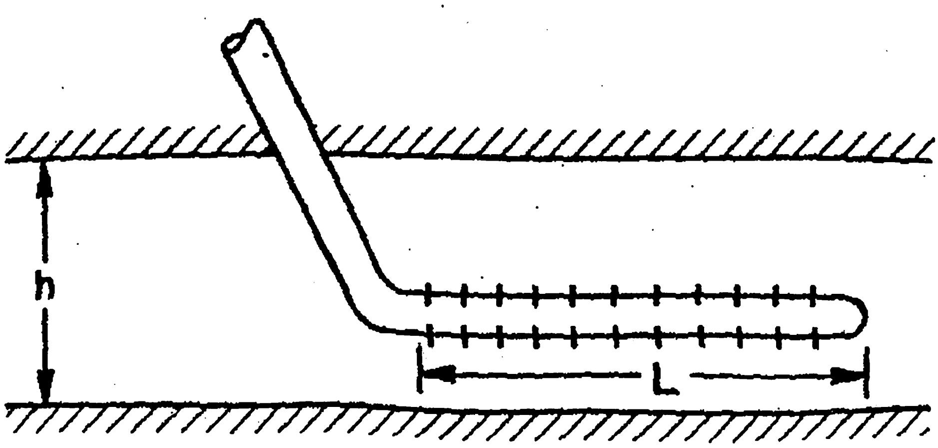


Fig. 7.3. A Schematic of a Horizontal Well

Thus a horizontal well represents a limiting case of an infinite-conductivity fracture where the fracture height is equal to the wellbore diameter. This also tells us that the hole diameter of a horizontal well would have an influence on its performance.

SKIN FACTOR:

Van Everdingen and Hurst[1] introduced the idea of a skin factor to the petroleum industry. They noticed that for a given flow rate, the measured bottom-hole flowing pressure was less than that calculated theoretically. This indicated to them that there was an additional pressure drop over that calculated theoretically. Moreover, this pressure response was found to be independent of time. They attributed this pressure drop to a small zone of damaged or reduced permeability around the wellbore. Van Everdingen and Hurst called this "invaded" zone, or damaged zone, a skin zone, and the associated pressure drop as a skin factor effect. To overcome the inherent mathematical limitations of this concept, Hawkins introduced a concept of thick skin. He showed $s = [(k/k_s) — 1] \ln(rs/r_w)$

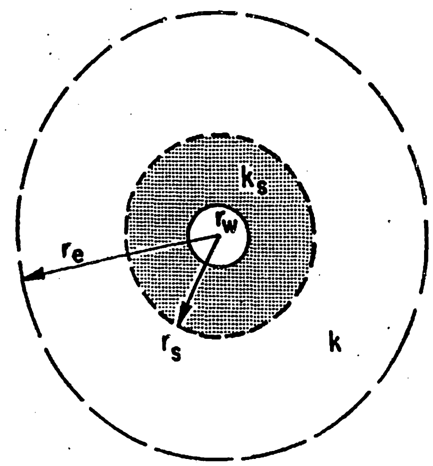


Fig. 7.4 Skin Damage Zone Schematic

Skin concept is only valid for steady and pseudo-steady states. Normally, skin factors are estimated using drill stem testing or pressure build up analysis.

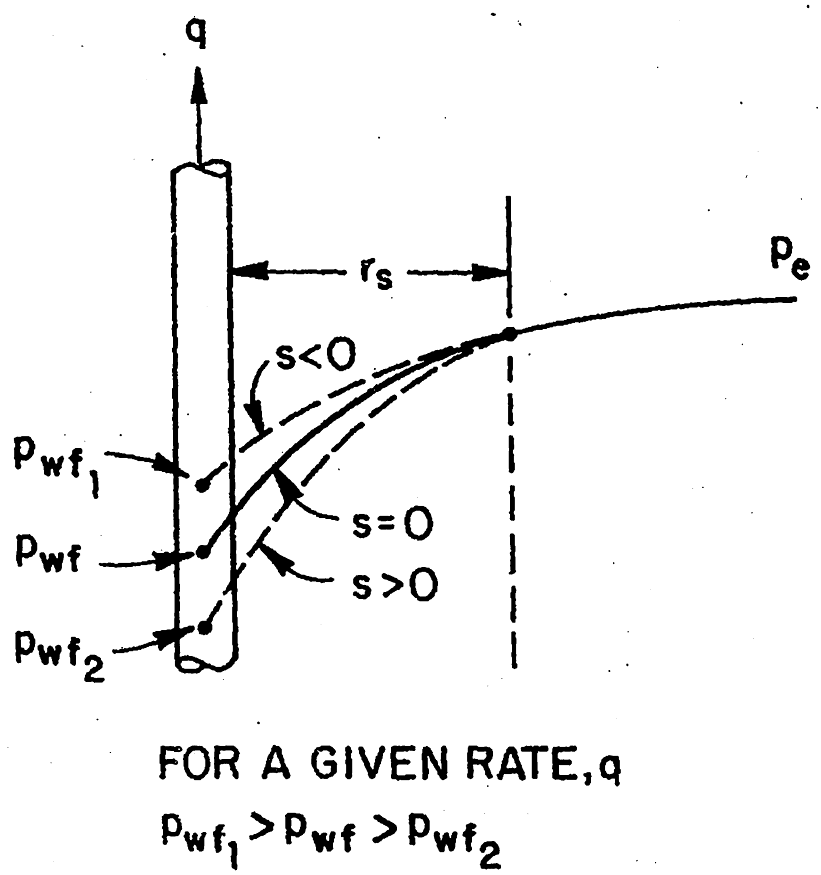


Fig. 7.5. Effect of Skin on Well Flow Pressure

Vertical well pressure drop due to skin is given by

$$(\Delta p)_{skin} = s(141.2\ \mu_o B_o/k)(q/h)$$

For horizontal well we have

$$(\Delta p)_{skin} = s(141.2\ \mu_o B_o/k)(q/L)$$

On comparing the above two equations, we observe that the pressure drop in skin region of a horizontal well is smaller than that in a vertical well. This is because the rate of fluid entry into the wellbore per unit length of a horizontal well is much smaller than that for a vertical well.

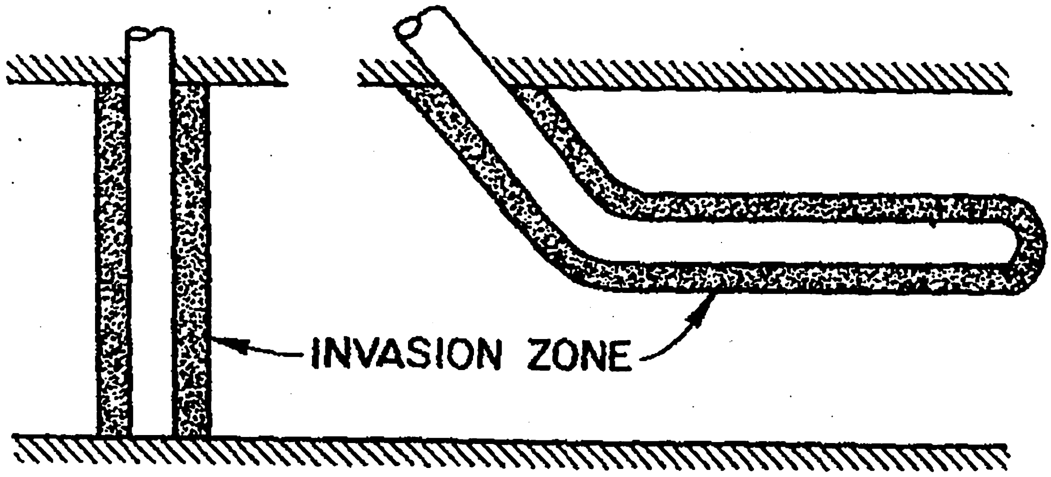


Fig. 7.6. Ideal Mud Damage Zones for Horizontal & Vertical Wells

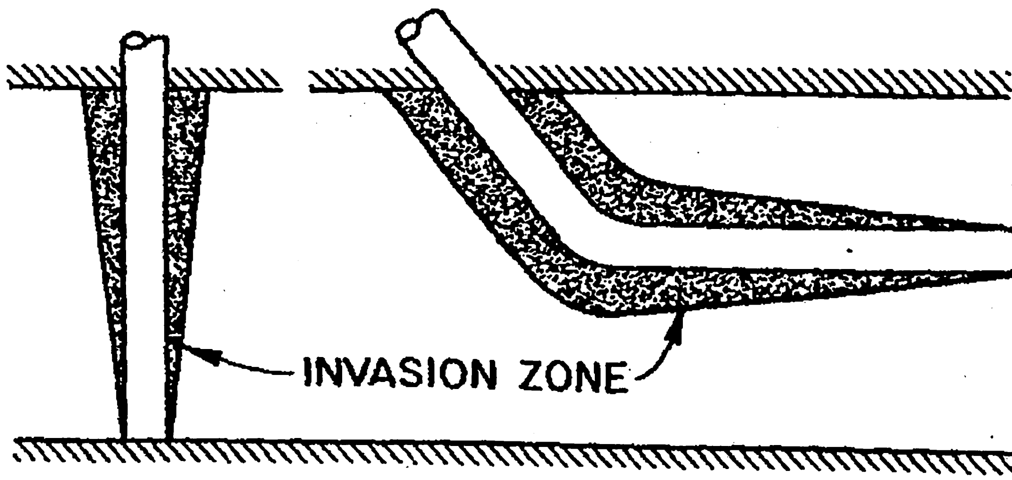


Fig. 7.7. Cone-shaped Damaged Zones

7.2 SKIN DAMAGE FOR HORIZONTAL WELLS:

It can be shown that for a given positive skin factor, the pressure drop in the skin region for a horizontal well is considerably than that for a vertical well. This shows that for a given skin damage the stimulation treatment to remove near wellbore damage would have less effect on the productivity of a horizontal well than on the productivity of a vertical well. Therefore, before deciding to stimulate a horizontal well, it is important to estimate the pressure loss in the skin zone and compare it with the overall pressure drop from the reservoir to the wellbore pressure. The minimum influence of near-wellbore damage on horizontal well productivity in a high permeability reservoir also explains the reasons for many successful horizontal well field projects in high permeability reservoirs.

In many reservoirs especially in low permeability reservoirs, after drilling vertical wells, the vertical wells are cemented and perforated. Prior to production, these wells are stimulated using propped or unpropped fractures. Without fracturing these wells don't produce at economic rates. In these types of reservoirs, vertical well drilling probably causes severe damage, but it is overcome by fracture stimulation. If a horizontal well is drilled in such a reservoir, the damage due to horizontal wells will be larger than that in the vertical well. This is because horizontal drilling takes a longer time than vertical drilling, resulting in a conical-shape damage zone. This damage zone can significantly reduce productivity of a horizontal well. Skin damage could vary along the well length. Based on the experience with vertical well skin damage, and vertical well drilling time, one can attempt to estimate damage along the length of a horizontal well. Availability of core data for damage or drill stem test data on vertical wells will be useful in constructing plots showing variation in the skin factor with the horizontal well length. These plots can be used to estimate expected average damage from a horizontal well. It is important to note that in a horizontal well test, the calculated damage value would represent an average value for the entire well. Based on the expected damage value, a proper stimulation and near- wellbore formation clean up procedure needs to be critically reviewed. A well completed as an open hole or with a slotted liner may be difficult to clean and special cleanup procedures may have to be devised. Swabbing the well is one alternative, but it can be time-consuming and may be inefficient to clean up long horizontal wells. Moreover, depending upon well turning radius, a swab tool may reach only up to the top of the curve section of the wellbore and it is difficult to reach with a swab tool in the horizontal well portion. Another option where severe damage is expected is to consider cementing and perforating horizontal wells.

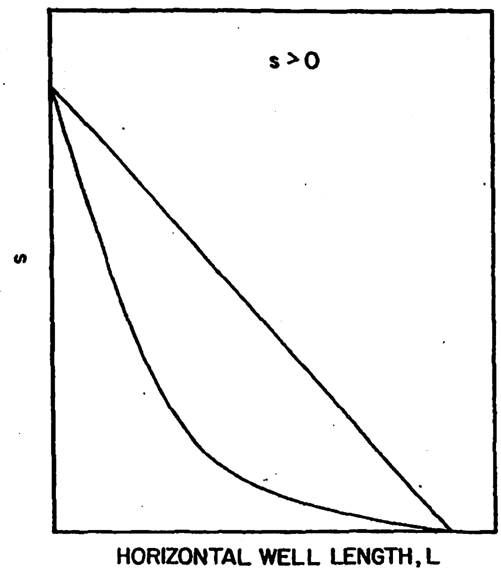


Fig. 7.7. A Possible Variation in Drilling Related Mechanical Skin Factor along the Well Length.

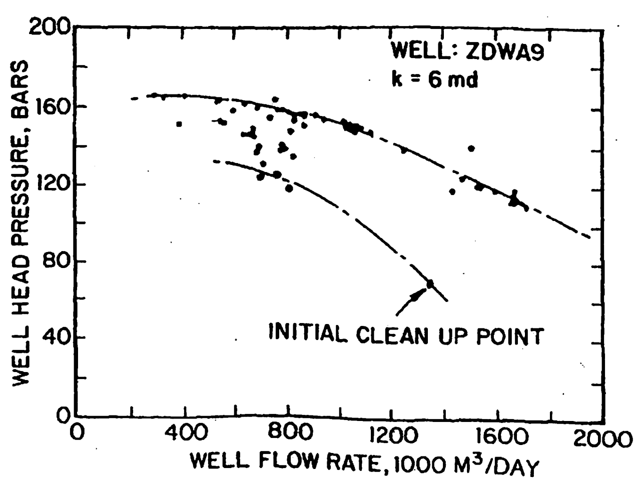


Fig. 7.8. Mud Clean-Up Effect in a Horizontal Gas Well

7.3 FLOW REGIMES:

The production data in the form of flow rate and flowing pressure are available in an oil and gas producing field. Additionally, testing of a well yields reservoir pressure and other formation properties such as permeability, skin, and drainage area. One practical approach is to use productivity index (PI) to characterize the performance of a well and also compare it with similar wells. The productivity index is also denoted by letter 'J' and mathematically expressed for an oil well as:

$$J = \frac{q}{\Delta p} = \frac{q}{(\bar{p} - p_w)}$$

In general, units used are bbl/day/psi or m3/day/kPa.

Productivity index is also considered as the measure of the capacity of the well. In this form PI represents a steady state flow condition.

During the operational life, the hydrocarbon producing well passes through various stages. These stages mainly depend on the pressure drop and the boundary conditions. There are four different flow scenarios, which occur during the operational life of the well. They are:

- Unsteady state.
- Pseudo – steady state.
- Steady state.
- Late Transient.

Unsteady state:

This is the condition of the well when the pressure disturbance caused by the flow has not reached any of the reservoir boundaries. This is also known as Infinite – acting or Transient state.

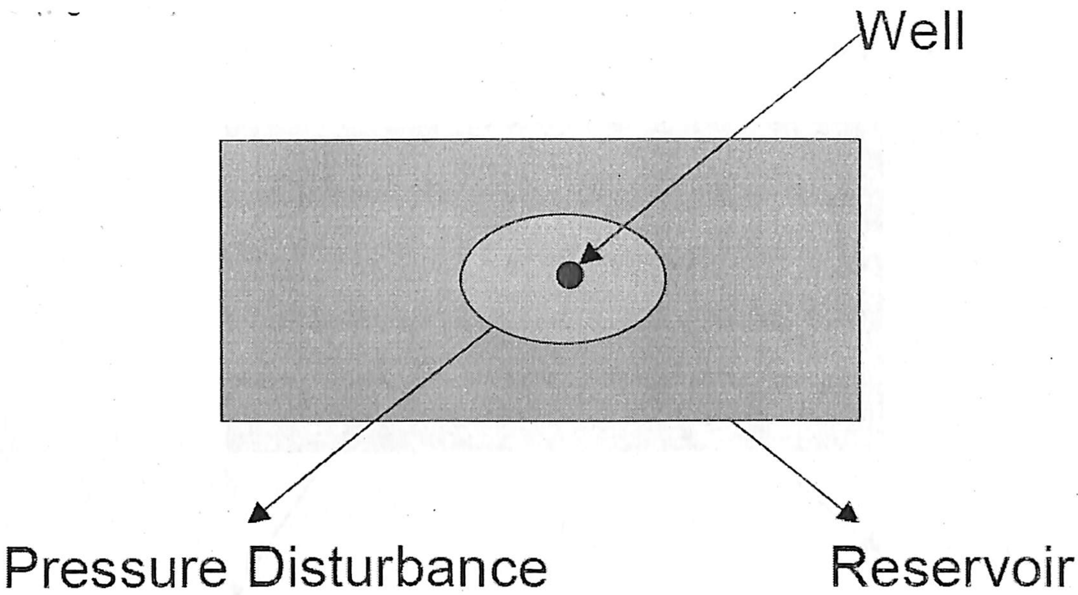


Fig. 7.9 Unsteady State

Mathematically, unsteady state is defined as:

$$\frac{\partial P}{\partial t} = f(r,t)$$

Pseudo – steady State:

This is the condition of the well in a bounded reservoir when the pressure disturbance caused by the flow has reached all of the reservoir boundaries. During this flow regime the reservoir behaves like a tank. The pressure throughout the reservoir decreases at the same constant rate.

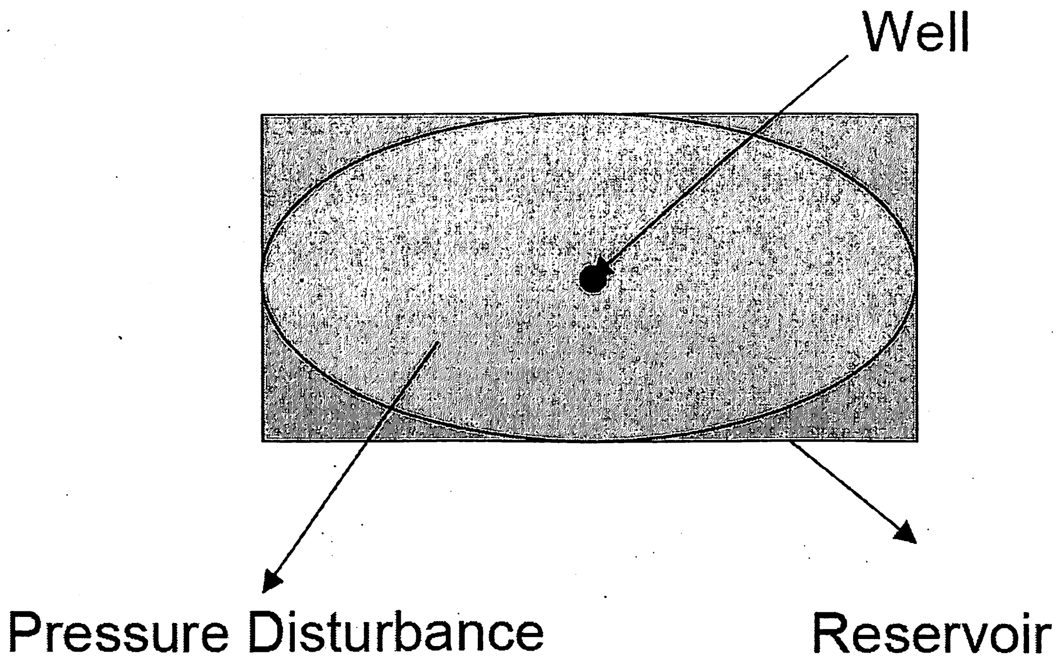


Fig. 7.10. Pseudo-Steady State

Mathematically, pseudo-steady state is given as:

$$\frac{\partial P}{\partial t} = \text{constant}$$

Steady state:

This condition occurs during the late time region when a constant pressure boundary exists. Constant pressure boundaries arise when the reservoir has aquifer support or gas cap expansion support.

Mathematically, steady state is given as:

$$\frac{\partial P}{\partial t} = 0$$

Late Transient State:

This is the state between unsteady state and pseudo – steady state. During this regime the pressure distribution reaches some of the boundaries but not all of it.

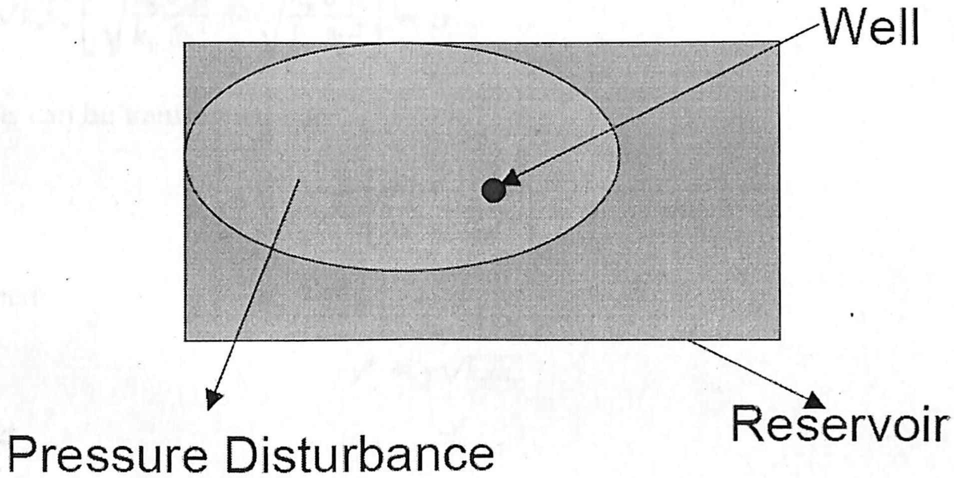


Fig. 7.11. Late Transient State

INFLUENCE OF AREAL ANISOTROPY[13]

In naturally fractured reservoirs, the permeability along the fracture trend is larger than in a direction perpendicular to fractures. In such cases, a vertical well would drain more length along the fracture trend. The derivation shown below can be used to estimate each side of a drainage area in an areally anisotropic reservoir. Assuming a single phase, steady-state (time independent) flow through porous formation, one can write the following equation.

$$\frac{\partial}{\partial x}\left(k_x \frac{\partial p}{\partial x}\right) + \frac{\partial}{\partial y}\left(k_y \frac{\partial p}{\partial y}\right) = 0$$

Assuming constant values of k and k in x and y directions, respectively, equation is rewritten as

$$k_x \frac{\partial^2 p}{\partial x^2} + k_y \frac{\partial^2 p}{\partial y^2} = 0$$

multiplying and dividing throughout by $\sqrt{k_x k_y}$,

$$\sqrt{k_x k_y}\left[\sqrt{\frac{k_x}{k_y}}\frac{\partial^2 p}{\partial x^2} + \sqrt{\frac{k_y}{k_x}}\frac{\partial^2 p}{\partial y^2}\right] = 0$$

This can be transformed into

$$\sqrt{k_x k_y}\left[\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y'^2}\right] = 0$$

where

$$y' = y\sqrt{k_x/k_y}$$

and

$$y = y'\sqrt{k_y/k_x}$$

Thus, an areally anisotropic reservoir would be the equivalent of a reservoir with an effective horizontal permeability of $\sqrt{k_x k_y}$ and the length along the high-permeability side is $\sqrt{k_y/k_x}$ times the length along a low- permeability side. Thus, if permeability along the fracture trend is 16 times larger than perpendicular to it, then drainage length along the fracture four times larger than the length perpendicular to the fracture. In such areally anisotropy reservoirs, it is difficult to drain larger reservoir length in the low-permeability direction using vertical wells. A horizontal well drilled along the low-permeability direction has the potential to drain a significantly larger area than a vertical well, resulting in a larger reserve for horizontal wells than vertical wells. Thus, horizontal wells are highly beneficial in areally anisotropic reservoirs. It is obvious that in naturally fractured formations, horizontal wells drilled in a direction perpendicular t the natural fractures would be highly beneficial. The success of horizontal wells in naturally fractured reservoirs, such as Austin Chalk formation in Texas, U.S.A., and Bakken Shaleformation in North Dakota, U.S.A., illustrates the advantage of horizontal drilling in areally anisotropic formations.

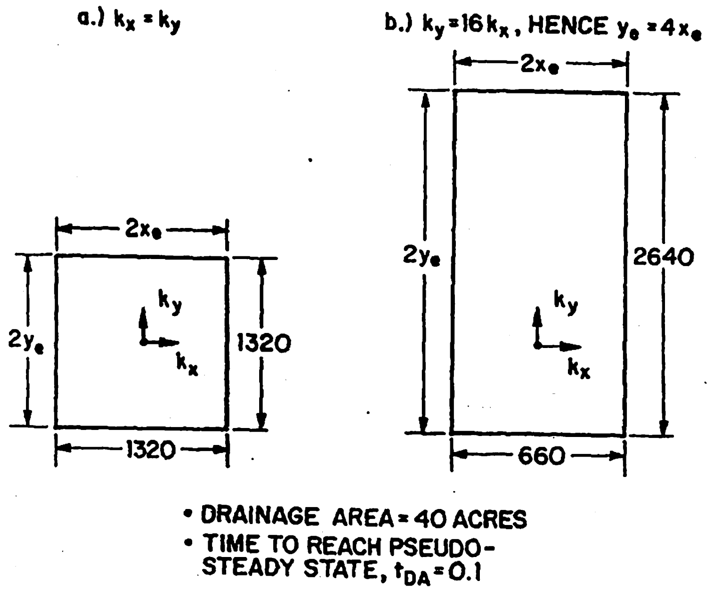


Fig. 7.12. Drainage Areas of a Vertical Well in Isotropic & Anisotropic Reservoirs

DRAINAGE AREA OF HORIZONTAL WELLS[3,2]

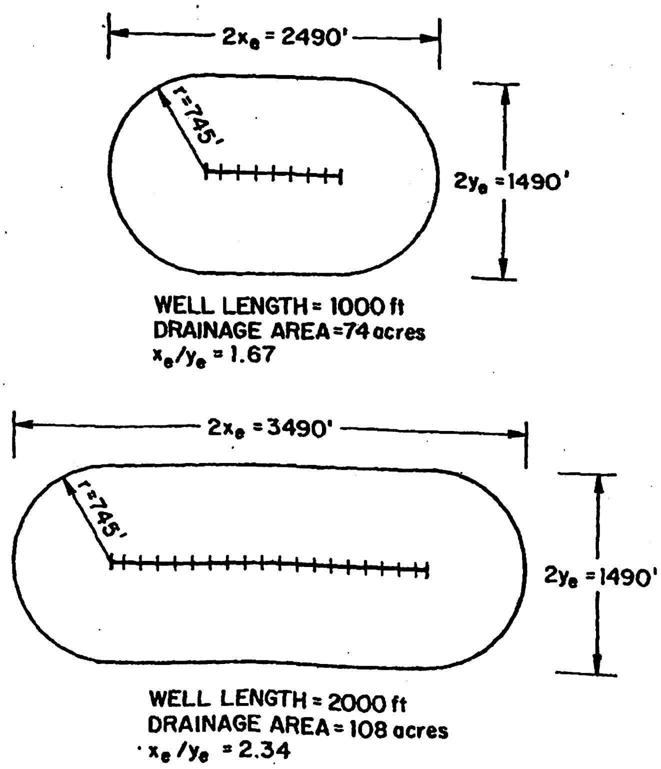


Fig. 7.13. Drainage Areas of 1000 & 2000 ft long Horizontal Wells

Due to longer well length, in a given time period under similar operating conditions, a horizontal well would drain a larger reservoir area than a vertical well. If a vertical well drains a certain reservoir volume (or area) in a given time, then this information can be used to calculate a horizontal well drainage area. A horizontal well can be looked upon as a number of vertical wells drilled next to each other and completed in a limited payzone thickness. Then, each end of a horizontal well would drain either a square or a circular area; with a rectangular drainage area at the center. This concept implicitly assumes that the reservoir thickness is considerably smaller than the sides of the drainage area. It is possible to calculate the drainage area of a horizontal well by assuming an elliptical drainage area in the horizontal plane, with each end of a well as a foci of drainage ellipse. In general, different methods give fairly similar results. As a rule of thumb, a 1000-ft-long horizontal well an drain twice the area of a vertical well while a 2000-ft-long well an drain three times the area of a vertical well in a given time. Thus, it is important to use larger well spacing for horizontal well development than that tied for vertical well development. In a fractured reservoir, where permeability in one direction is higher than the other, then the well would accordingly drain a larger length in a high-permeability direction by a factor of $\sqrt{k_y/k_x}$ where k represents higher permeability in the horizontal plane, and k represents lower permeability in the horizontal plane.

Example 1:

A 400-acre lease is to be developed using 10 vertical wells. An engineer suggested drilling either 1000- or 2000-ft-long horizontal wells. Calculate the possible number of horizontal wells that will drain the lease effectively. Assume that a single vertical well effectively drains 40 acres.

Solution:

A 40-acre vertical well would drain a circle of radius 745 ft. If r_{ev} is a drainage radius of a vertical well, then

$$\text{Area of a circle} = \pi r_{ev}^2 = 40 \text{ acres} \times 43{,}560 \text{ sq ft/acre}$$

$$r_{ev} = 745 \text{ ft}$$

Two methods can be employed to calculate horizontal well drainage area, on the basis of a 40-acre drainage area of a vertical well.

Method I

As shown in Fig. 13, a 1000-ft-long well would drain 74 acres. The drainage area is presented as two half circles at each end and a rectangl in the center. Similarly, as shown in Fig.14, a 2000-ft-long well would drain 108 acres.

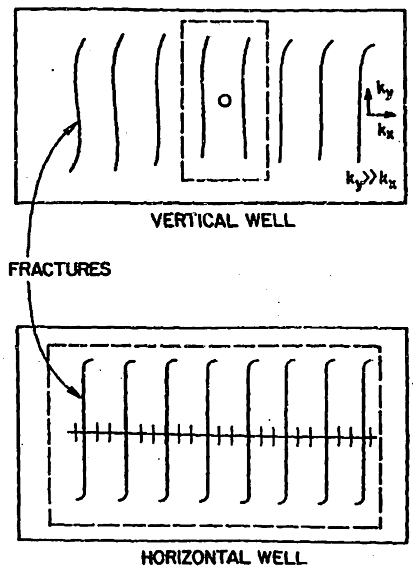


Fig. 7.14. Drainage Areas of Vertical & Horizontal Wells in a fractured reservoir

Method II

If we assume that the horizontal well drainage area is an ellipse in horizontal plane, then for a 1000-ft-long well,

$$a = \text{half major axis of an ellipse} = (L/2) + 745 = (1000/2) + 745 = 1245\ \text{ft}$$

$$b = \text{half minor axis of an ellipse} = 745\ \text{ft}$$

$$\text{Drainage area} = \pi ab/43{,}560 = \pi(1245 \times 745)/43{,}560 = 67\ \text{acres}$$

for a 2000-ft-long well,

$$a = \text{half major axis of an ellipse} = (L/2) + 745 = (2000/2) + 745 = 1{,}745\ \text{ft}$$

$$b = \text{half minor axis of an ellipse} = 745\ \text{ft}$$

$$\text{Drainage area} = \pi ab/43{,}560 = \pi(1745 \times 745)/43{,}560 = 94\ \text{acres}$$

As we see, two methods give different answers for drainage area. If we take average areas using two methods, a 1000-ft well would drain 71 acres and a 2000-ft well would drain 101 acres. Thus, a 400-acre field can be drained by 10 vertical wells; 6 1000-ft-long wells; or 4 2000-ft-long wells. Thus, horizontal wells seem very appropriate for offshore and hostile environment applications where a substantial upfront savings can be obtained by drilling long horizontal wells. This is because a large area can be drained by using a reduced number of wells. This reduces the number of slots that are required on offshore platforms, and thereby significantly reduces the cost of these platforms.

7.4 STEADY-STATE SOLUTIONS[13]

The steady-state analytical solutions are the simplest form of horizontal well solutions. These equations assume steady state, i.e., pressure at any point in the reservoir does not change with time.

In practice, very few reservoirs operate under steady-state conditions. In fact, most reservoirs exhibit change in reservoir pressure over time. In spite of this, steady-state solutions are widely used because (1) they are easy to derive analytically; (2) it is fairly easy to convert steady-state results to either transient and pseudo-steady state results by using concepts of ex panding drainage boundary over time and effective wellbore radius and shape factors, respectively; and (3) steady-state mathematical results can he verified experimentally by constructing physical models in a laboratory.

There are different methods3 for predicting the PI for Steady state Horizontal wells. They are:

- Borisov's method.
- The Giger – Reiss – Jourdan method.
- Joshi's method.
- The Renard – Dupuy method.
- The Giger Method.

Borisov's method[4]

Borisov proposed the following expression for predicting the productivity index of a horizontal well in an isotropic reservoir, i.e., $k_v = k_h$.

$$q_h = \frac{2\pi k_h h \Delta p/(\mu_o B_o)}{\ln[(4r_{eh}/L)] + (h/L)\ln[h/(2\pi r_w)]}$$

The Giger – Reiss – Jourdan method[5]

Giger – Reiss – Jourdan proposed the following expression for predicting the productivity index of a horizontal well in an isotropic reservoir, i.e., $k_v = k_h$.

$$J_h/J_v = \frac{\ln(r_{ev}/r_w)}{\ln\left[\frac{1+\sqrt{1-[L/(2r_{eh})]^2}}{L/(2r_{eh})}\right] + (h/L)\ln[h/(2\pi r_w)]}$$

Joshi's method[7]

Joshi proposed the following expression for estimating the productivity index of a horizontal well in an isotropic reservoir:

$$q_h = \frac{2\pi k_h h \Delta p/(\mu_o B_o)}{\ln\left[\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right] + (h/L)\ln[h/(2r_w)]}$$

$$a = (L/2)\left[0.5 + \sqrt{0.25 + (2r_{eh}/L)^4}\right]^{0.5}$$

The Renard – Dupuy method[6]

For an isotropic reservoir, Renard and Dupuy proposed the following expression:

$$q_h = \frac{2\pi k_h h\Delta p}{\mu_o B_o}\left[\frac{1}{\cosh^{-1}(X) + (h/L)\ln[h/(2\pi r_w)]}\right]$$

$X = 2a/L$ for ellipsoidal drainage area

a = half the major axis of drainage ellipse

In the above equations, L represents horizontal well length, h represents reservoir height, r represents wellbore radius, k_h is horizontal permeability, and r_{ev} and r_{eh} represent drainage radius of vertical and horizontal wells, respectively. Additionally, μ_o is oil viscosity, B_o is oil formation volume factor, ?p is pressure drop from the drainage boundary to the wellbore, and q_h, is flow rate of a horizontal well. The productivity index J_h can be obtained by dividing qh by ?p.

These equations can be modified to the practical field units by replacing 2pkh in the numerator by 0.007078. In this case the production rate is given in STB/day, permeability in md, reservoir thickness in ft, pressure drop in psi, oil viscosity in cp, and oil formation volume factor in RB/STB.

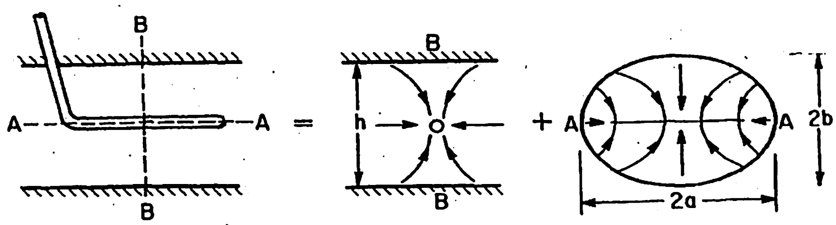


Fig. 7.15. A Division of a 3-D problem into two 2-D problems

The comparison of various equations shows a small difference between the various equations by a term of (h/L) lnp in the denominator of the flow equations. However, the effect of this small difference on the calculations of production rate is normally minimal. If the length of a horizontal well is significantly longer than the reservoir thickness, i.e., L>> h, then the solution reduces to

$$q_h = \frac{0.007078\ k_h h\ \Delta p/(\mu_o B_o)}{\ln (4r_{eh}/L)}$$

This can be rewritten as

$$q_h = \frac{0.007078\ k_h h\ \Delta p/(\mu_o B_o)}{\ln [r_{eh}/(L/4)]}$$

Thus, for a long horizontal well, the effective wellbore radius, $r_w' = L/4$, is the same as that for a fully penetrating infinite-conductivity vertical fracture. Thus, in a limiting case, at least for a single-phase flow, productivity of a horizontal well approaches that of a fully penetrating, infinite-conductivity vertical fracture.

Example 2:

A 1000-ft-long horizontal well is drilled in a reservoir with the following characteristics.

$k_v = k_h$ 75md, μ_o=0.62cp

h = 160ft, B_o = 1.34 RB/STB

r = 0.365 ft

Calculate the steady-state horizontal well productivity using different methods if a typical vertical well drains 40 acres.

Solution:

If a vertical spacing is 40 acres, then a 1000- ft-long horizontal well would drain about 80 acres. For a vertical well draining 40 acres, drainage radius r_{ev} for a circular drainage area is 745 ft. The productivity index for a vertical well can be calculated as:

$$J_v = \frac{0.007078 \times 75 \times 160/(0.62 \times 1.34)}{\ln(745/0.365)}$$
$$= 102.23/\ln(2041)$$
$$= 13.4 \text{ STB/(day-psi)}$$
$$\approx 13 \text{ STB/(day-psi)}.$$

For a horizontal well draining 80 acres, the drainage radius of a circular drainage area is 1053 ft. Thus, r_{eh} = 1053 ft.

Using the earlier mentioned formulae for calculating PI ,the results can be summarized as given below:

J_h/J_v by Different Methods

METHODS	PRODUCTIVITY INDEX J_h, STB/(day/psi)	J_h/J_v	AREAL PRODUCTIVITY INDEX $= J_h$/acre STB/(day-psi-acre)
Borisov	48	3.7	0.60
Giger	50	3.8	0.63
Joshi	44	3.4	0.56

7.5 PARAMETERS INFLUENCING PRODUCTIVITY

1. INFLUENCE OF RESERVOIR HEIGHT ON WELL PRODUCTIVITY[8]

The influence of reservoir height on horizontal wells is quite significant. For a given length of a horizontal well, the incremental gain in reservoir contact area in a thin reservoir is much more than that in a thick reservoir. For example, assume drilling a 1000-ft-long horizontal well in two possible target zones (one zone with a thickness of 50 ft and the other zone with a thickness of 500 ft). The incremental gain in the contact area in a 50-ft-thick reservoir by drilling a 1000-ft-long horizontal well is about 20 times more than that with a vertical well. In contrast, in a 500-ft-thick reservoir, the incremental gain in contact area by drilling a 1000-ft-long horizontal well is only twofold. Thus, significantly more gain in contact area can be achieved in a thin reservoir than in a thick reservoir. It is important to note that the terms thick and thin are relative. One should look for incremental contact area rather than using a specific definition of thick and thin reservoirs.

The influence of reservoir height on horizontal well productivity can be estimated using steady-state equations. Fig. 16 shows the change in productivity of a horizontal well in a 160-acre drainage area under steady-state conditions. The results assume isotropic reservoir. As evident from the figure the incremental gain in well productivity by increasing the length of the horizontal well decreases with increasing reservoir thickness or height. Fig. 17 shows the same results in terms of skin factors.

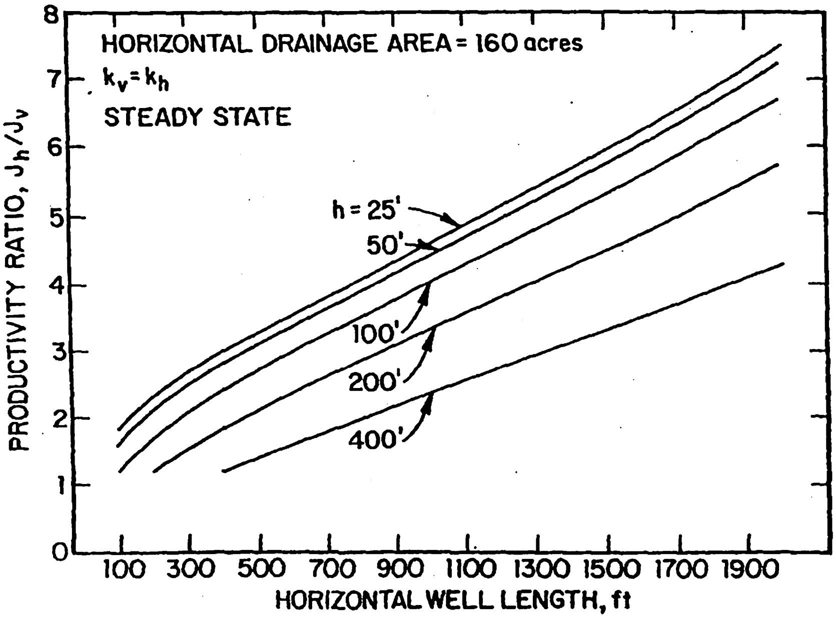


Fig. 7.16. PI ratio vs Well length for different Reservoir thickness

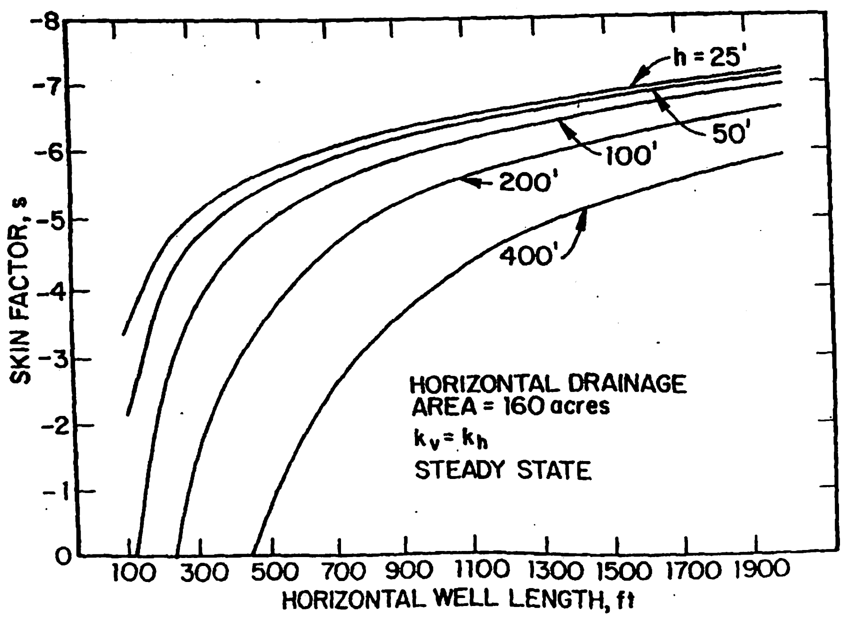


Fig. 7.17. Skin factor vs Well length for different reservoir thickness

2. INFLUENCE OF RESERVOIR ANISOTROPY[7]

If we have a reservoir with different horizontal & vertical permeabilities, then we can write the Laplace equation which represents steady-state flow as:

$$k_h\left(\frac{\partial^2 p}{dx^2}\right) + k_v\left(\frac{\partial^2 p}{dz^2}\right) = 0$$

This can be rewritten as

$$\left(\frac{\partial^2 p}{\partial x^2}\right) + \left(\frac{\partial^2 p}{\partial z'^2}\right) = 0$$

Where

$$z' = z\sqrt{k_h/k_v}$$

And effective permeability k'_{eff}, is defined as

$$k_{eff} = \sqrt{k_v k_h}$$

Thus, the influence of reservoir anisotropy can be accounted for by modifying the reservoir thickness as

$$h' = h\sqrt{k_h/k_v}.$$

Thus the steady-state productivity equations are suitably modified as follows:

Joshi Method:[7]

$$J_h = \frac{0.00708 h k_h}{\mu_o B_o \left[\ln(R) + \left(\frac{B^2 h}{L} \right) \ln\left(\frac{h}{2 r_w} \right) \right]}$$

$$B = \sqrt{\frac{k_h}{k_v}}$$

$$R = \frac{a + \sqrt{a^2 - (L/2)^2}}{(L/2)}$$

Here 'a' is half the major axis of the drainage ellipse and is given by:

$$a = (L/2)\left[0.5 + \sqrt{0.25 + (2 r_{eh} / L)^4} \right]^{0.5}$$

Renard-Dupuy Method:[6]

$$J_h = \frac{0.00708 h k_h}{\mu_o B_o \left[\cosh^{-1}\left(\frac{2a}{L} \right) + \left(\frac{Bh}{L} \right) \ln\left(\frac{h}{2\pi r'_w} \right) \right]}$$

where

$$r'_w = \frac{(1+B) r_w}{2B}, \quad B = \sqrt{\frac{k_h}{k_v}}$$

where $X = 2a/L$ for an ellipsoidal drainage area,

Example 2:

A 2000-ft-long horizontal well is to be drilled in a reservoir with vertical permeability of about one-half of the horizontal permeability. The horizontal well is drilled on a 160-acre spacing. Other reservoir parameters are

k_h = 5 md,

μ_o=0.3 cp, r_w' = 0.365 ft

h = 50 ft

B_o = 1 .2 RB/STB

Calculate the horizontal well productivity by Joshi and Renard- Dupuy methods for k_v/k_h =0.5 & 0.1.

Solution:

Using the formulae mentioned earlier the productivities are calculated.

The results are summarized below:

Horizontal Well Productivity, J_h, STB/(day-psi)

METHOD	k_v/k_h = 0.1	k_v/k_h = 0.5
Joshi	3.2	3.9
Renard & Dupuy	3.6	4.1

The above example shows that the reduction in vertical permeability has the same effect as drilling a horizontal well in a thicker reservoir and reducing incremental contact area.

Good vertical permeability is essential for successful horizontal well operations. If one has to drill a horizontal well in low vertical permeability reservoir, then it is essential to create reasonable vertical permeability artificially by fracturing a horizontal well. However if on plans to increase vertical permeability by fracturing a horizontal well, then either medium radius or long radius drilling techniques will have to be used so that the small portions of a long well can be isolated for effective stimulation treatment. The zonal isolation in a long horizontal well can be obtained either by cementing &

perforating the liner or small portions of a solid liner can be isolated into several sections by using external casing packers.

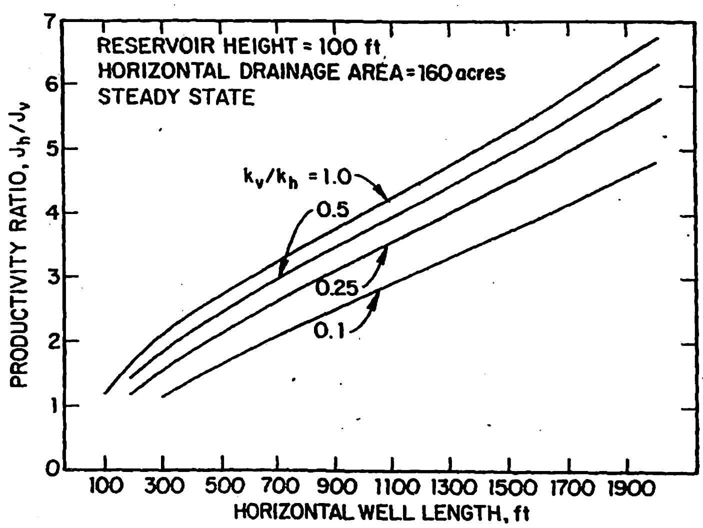


Fig. 7.18. Effects of vertical permeability on Productivity ratio of Horizontal & Vertical Wells.

TABLE 8.1- INFLUENCE OF RESERVOIR ANISOTROPY ON HORIZONTAL WELL PRODUCTIVITY INCREASE AS COMPARED TO A VERTICAL WELL

J_h/J_v

HORIZONTAL LENGTH (ft)	$(k_v/k_h) = 0.1$	$(k_v/k_h) = 0.5$	$(k_v/k_h) = 1.0$
	RESERVOIR HEIGHT = 25 ft		
100	1.07	1.53	1.67
200	1.59	2.04	2.17
500	2.58	3.02	3.13
1000	3.86	4.33	4.44
1500	5.11	5.65	5.77
2000	6.48	7.13	7.28
	RESERVOIR HEIGHT = 50 ft		
100	—	1.14	1.34
200	1.09	1.66	1.87
500	1.99	2.66	2.87
1000	3.16	3.94	4.16
1500	4.27	5.21	5.46
2000	5.46	6.60	6.91
	RESERVOIR HEIGHT = 100 ft		
200	—	1.17	1.42
500	1.32	2.10	2.40
1000	2.24	3.29	3.65
1500	3.12	4.43	4.86
2000	4.04	5.66	6.19
	RESERVOIR HEIGHT = 200 ft		
500	—	1.42	1.76
1000	1.37	2.40	2.86
1500	1.96	3.32	3.90
2000	2.57	4.28	5.01
	RESERVOIR HEIGHT = 400 ft		
500	—	—	1.11
1000	—	1.50	1.93
1500	1.08	2.14	2.71
2000	1.43	2.79	3.52

3. WELL ECCENTRICITY[8,13]

For drilling a horizontal well, it is essential to decide on tolerance limits for well elevation. In other words, one has to decide how much deviation from a vertical elevation is tolerable. For small tolerance limits (± 5 ft), several measurements and surveys are required as the horizontal well is being drilled. Well drilling time is proportional to the number of directional surveys required.

The type of reservoir determines the drilling elevation tolerance..

1. Reservoirs with closed top and bottom boundaries: In this case, bottom water and top gas are absent. Ideally, one would like to drill a well at the reservoir elevation center. A loss of productivity is expected when the well is not at the elevation center. This is because a long horizontal well drilled in a thin reservoir acts as though it is a vertical fracture intersecting the entire reservoir height. A horizontal well, which acts as a fluid withdrawal conduit can be located anywhere in this vertical plane, with a minimum loss of productivity regardless of well location.
2. Reservoirs with water and/or gas coning: In these reservoirs, well location in the vertical plane is very important. A well location in the vertical plane, especially for a long well, would not cause a significant change in well productivity. However, the location of the well in the vertical plane would determine the breakthrough time of either gas or water or both, and subsequent changes in gas-oil ratio (GOR) and water-oil ratio (WOR). Thus, the well location in the vertical plane will affect the ultimate reserves producible from a well.

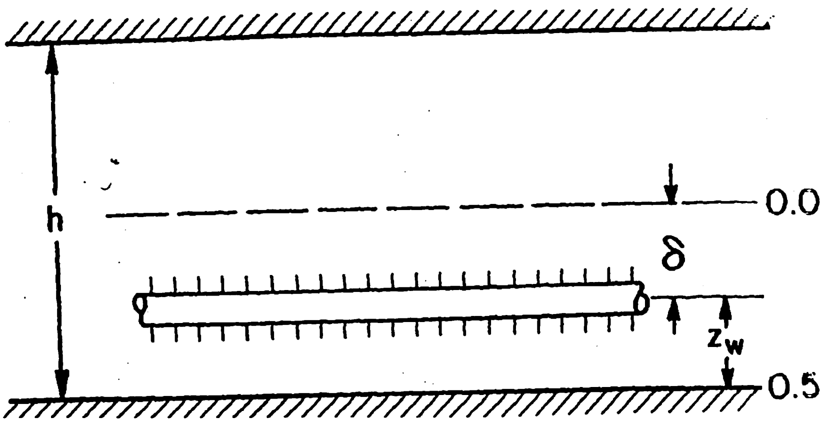


Fig. 7.19. A Schematic View of an Off-Centered Horizontal Well.

STEADY-STATE EQUATIONS

Fig. 19 shows a schematic diagram of an off-centered horizontal well in a vertical plane. In the figure d represents well eccentricity. The influence of eccentricity on the well production rate is calculated using the following equation.

$$q_h = \frac{0.007078\, k_h\, h\, \Delta p/(\mu_o B_o)}{\ln\left[\dfrac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] + (\beta h/L)\ln\left[\dfrac{(\beta h/2)^2 + \beta^2 \delta^2}{(\beta h\, r_w/2)}\right]}$$

for $L > \beta h$, $\delta < h/2$ and $L < 1.8\, r_{eh}$

q_h = oil flow rate, STB/day
h = reservoir height, ft
Δp = pressure drop, psi
k_h = horizontal permeability, md
μ_o = oil viscosity, cp
B_o = oil formation factor, RB/STB
r_w = wellbore radius, ft
L = horizontal well length, ft
δ = horizontal well eccentricity, ft

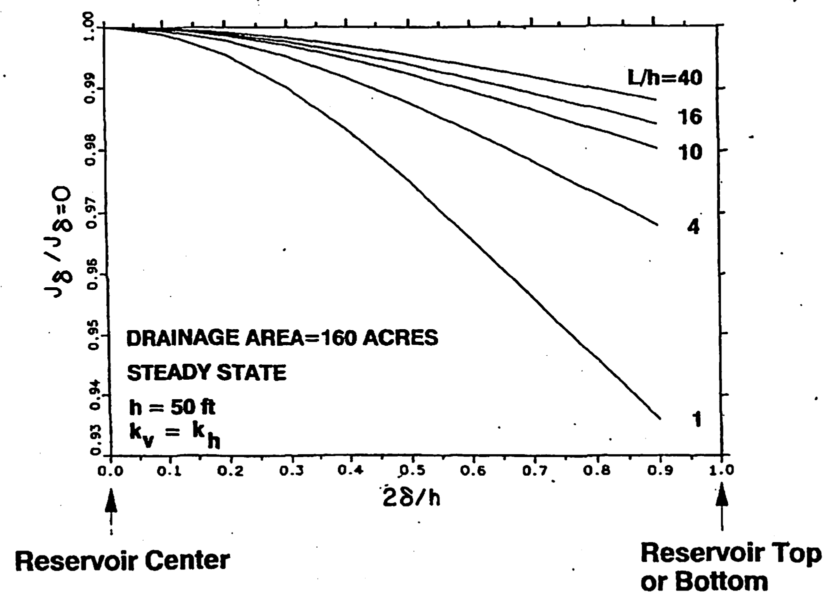


Fig.7.20. Influence of Horizontal Well Eccentricity on Productivity.

The above figure compares the productivities of an off-centered horizontal well with that of a centered well for different well eccentricities. It can be seen that if the horizontal well is sufficiently long as compared to the reservoir height, the well can be located anywhere in the vertical plane without significant loss of productivity. In general, a horizontal well's performance is not significantly affected by eccentricity as long as the well is located between +- 25% from the reservoir centre.

7.6 HORIZONTAL WELLS vs FINITE-CONDUCTIVITY FRACTURES[10, 2, 13]

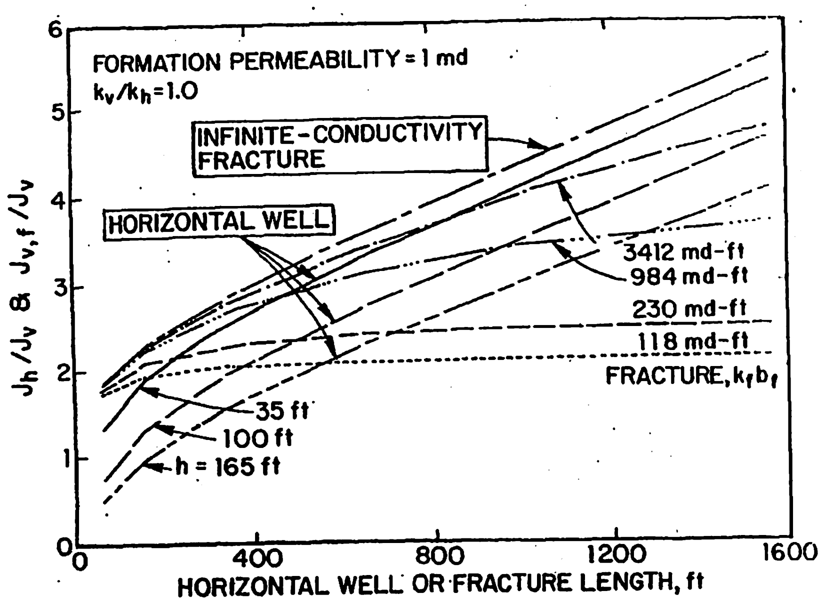


Fig. 7.21. A Comparison of Productivities of Horizontal and Stimulated Vertical Wells

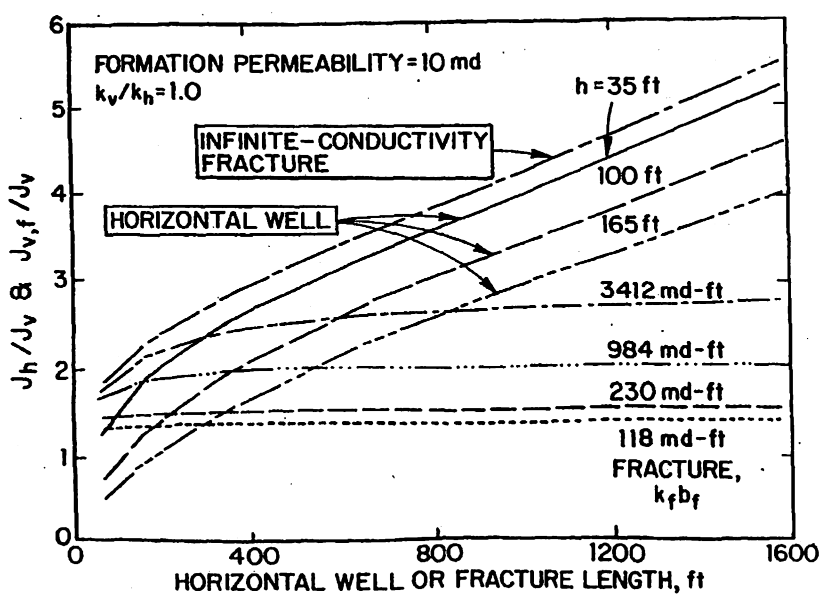


Fig. 7.22. A Comparison of Productivities of Horizontal and Stimulated Vertical Wells

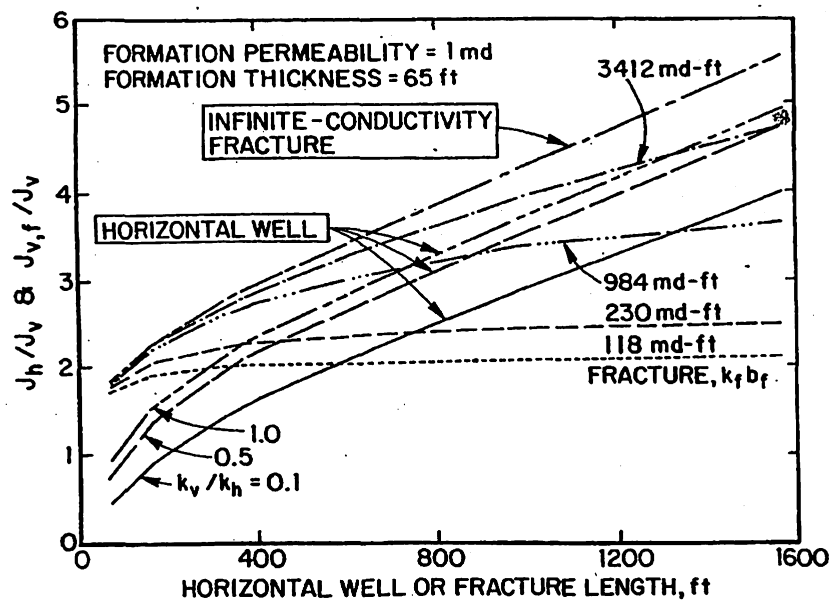


Fig. 7.23. A Comparison of Productivities of Horizontal and Stimulated Vertical Wells

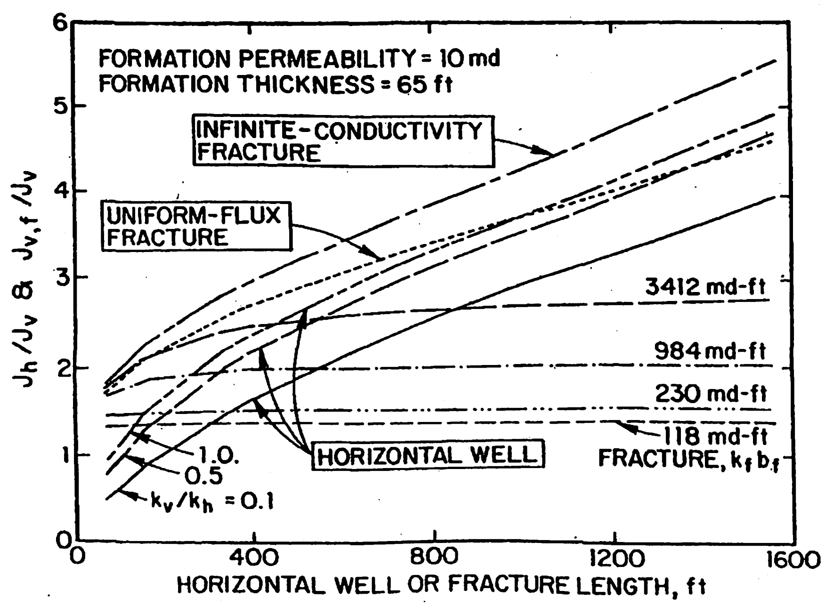


Fig. 7.24 A Comparison of Productivities of Horizontal and Stimulated Vertical Wells

The above figures depict comparisons of horizontal well productivities with productivities of fully penetrating fractures of the same length. Thus loss in productivity due to partial fracture penetration is ignored. The comparison is based on steady-state productivity indices of horizontal wells & fractured vertical wells.

Figures 21 & 24 tell us that in reservoirs with permeability greater than 10 md, conventional fracturing has a minimum effect in enhancing well productivity. This is because of a pressure drop within the fracture itself, which is comparable to reservoir pressure drop. In contrast, with a horizontal well, one can achieve significant productivity improvement by drilling long wells, as long as vertical permeability is sufficiently high.

Another method to compare horizontal wells with hydraulically fractured vertical wells is to calculate the effective wellbore radius, of a fractured vertical well that is required to produce at the same rate as a horizontal well. This can be accomplished using the following expression:

$$r'_w = \frac{r_{ev}\,(L/2)}{[a + \sqrt{a^2 - (L/2)^2}]\,[\beta h/(2r_w)]^{(\beta h/L)}}$$

And also

$$r'_w = m\,x_f$$

In the above equations, rn= 0.5 for an infinite-conductivity vertical fracture. Additionally, r_w' is an effective wellbore radius of a fractured vertical well in ft, a is calculated separately, r_{ev} is drainage radius of a fractured vertical well in ft, and ß is equal to $(k_v/k_h)^{\wedge 1/2}$. This equation shows that in low- permeability formations, the economic feasibility of a horizontal well strongly depends on the anisotropy, i.e. on the value of ß. For high ß values, i.e., in reservoirs with low vertical permeability, short fracture lengths are required in a vertical well to match the productivity of a horizontal well. Figure 25 shows fracture half-length sizes that are required to match productivities of horizontal wells.

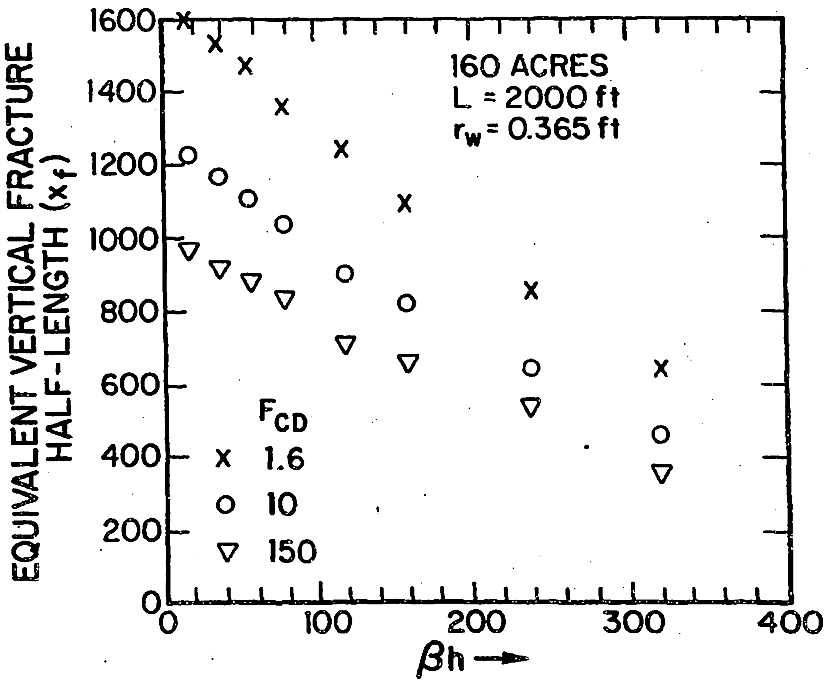


Fig. 7.25. An Equivalent Fracture Half-Length Needed in a Vertical Well to Match Horizontal Well Productivity.

The figure clearly shows that in thin formation and in high vertical permeability formations, i.e., at small ßh values, fractured vertical wells should have very long fracture lengths to match the productivity of horizontal wells.

In mature petroleum environments such as North and South America, an estimated 80% or more of all wells are hydraulically fractured (Willard, 1989). Hydraulic fracturing is a long-established means of completing and stimulating wells in moderate- to low-permeability reservoirs. Recently, there has been a tendency to fracture higher permeability formations as well, either to bypass near-wellbore damage or to control sand production by reducing pressure drawdown.

Reduced pressure drawdown, of course, also represents one of the main benefits of horizontal wells. This raises the possibility of using horizontal wells in place of fractured vertical wells. To evaluate this possibility, we must compare each alternative based on expected well performance.

Mukherjee and Economides (1991)[11] developed the following comparison for equal well performance:

$$r'_{wD} x_f = \frac{r_{eV} L/2}{\left[a + \sqrt{a^2 - (L/2)^2}\right]\left(\frac{I_{ani} h}{(I_{ani}+1) r_w}\right)^{I_{ani} h / L}} \quad \textbf{(3.8)}$$

where variables are those used in Equation 1.1.

$$q = \frac{k_H h (p_e - p_{wf})}{141.2 B \mu \left[\ln\left(\frac{a + \sqrt{a^2 - (L/2)^2}}{(L/2)}\right) + \left(\frac{I_{ani} h}{L} \times \ln \frac{I_{ani} h}{r_w (I_{ani} + 1)}\right)\right]} \quad \textbf{(3.1)}$$

xf is the fracture half-length in the vertical well, and r'_{wD} is the dimensionless effective wellbore radius, which is a function of the relative fracture capacity a (Prats, 1962):

$$\alpha = \frac{\pi k x_f}{2 k_f w} \quad \textbf{(3.9)}$$

This relative capacity parameter is related to the fracture conductivity (FCD) by

$$F_{CD} = \frac{\pi}{2\alpha} \quad \textbf{(3.10)}$$

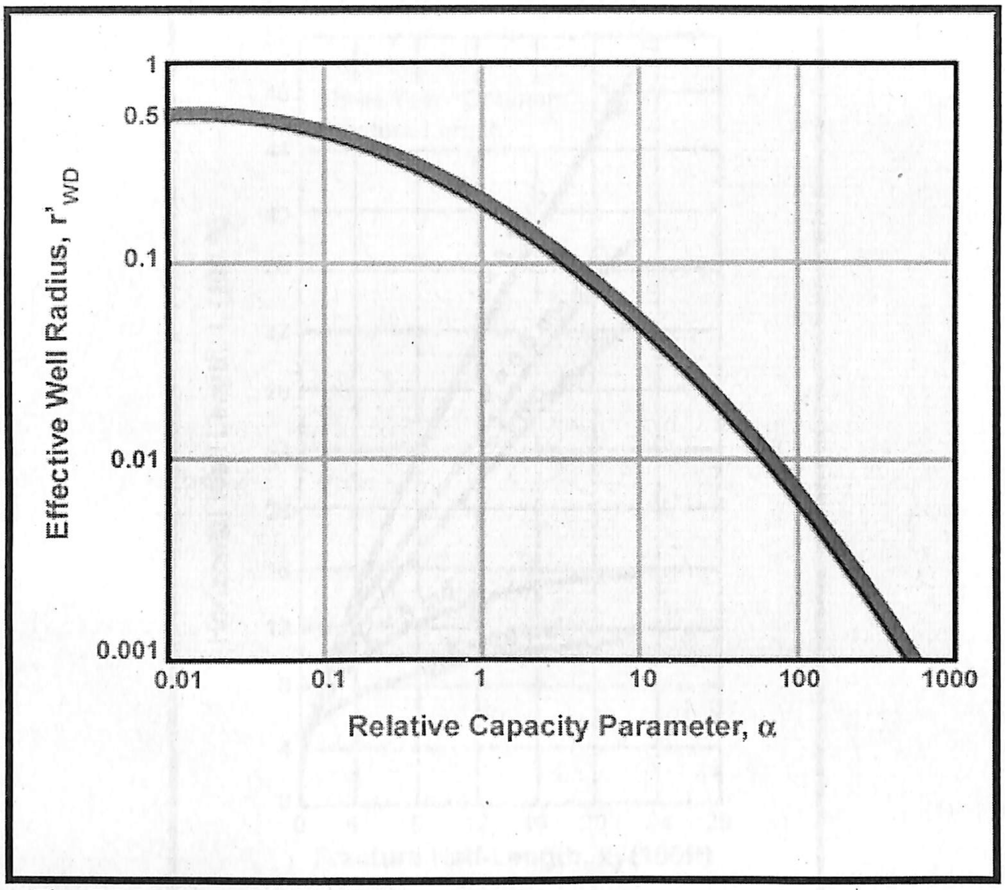


Fig. 7.26.

Fig. 26. relates the relative capacity parameter and the dimensionless well-bore radius. Using this relationship and Equation 3.8 we can determine the required section length for a horizontal well to perform at the same level as a hydraulically fractured vertical well having a fracture half-length x_f and a dimensionless effective wellbore radius r'_{wD}.

Fig.28(Brown and Economides, 1992)[9] is such a comparison for five different reservoir permeabilities, plotting the vertical well fracture half-length and the required horizontal wellength.

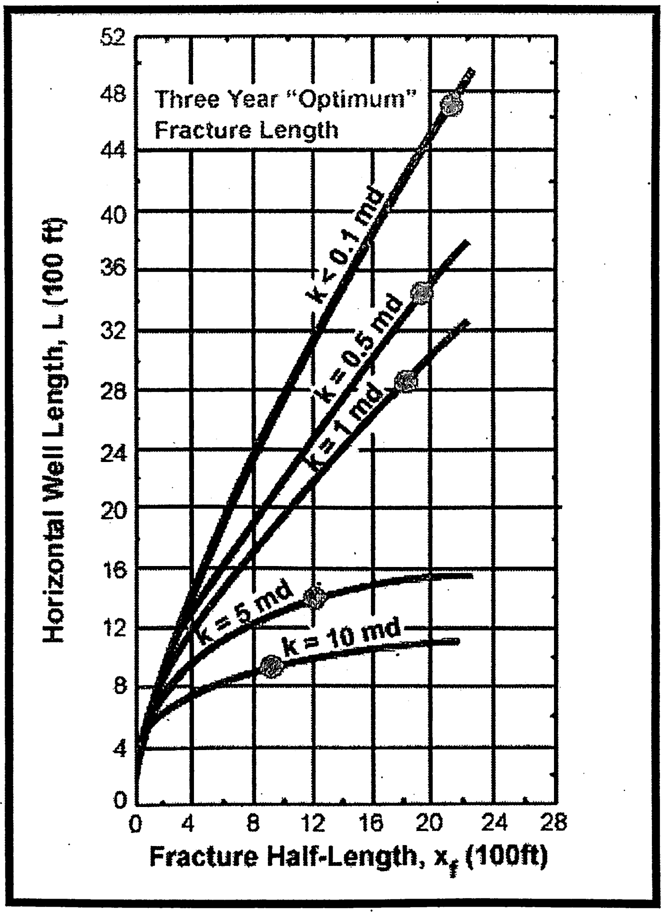


Fig. 7.27.

It also shows the optimum fracture lengths, based on a Net Present Value (NPV) calculation. For example, for a reservoir permeability of 1 md, the optimum fracture half-length is 1,800 ft [549 m]; for a horizontal well to produce at the same level, its section length would have to be 2,800 ft [853 m]. The decision regarding a horizontal versus a fractured vertical well thus becomes an issue of cost, and of whether we can attain the optimum fracture length.

On the other hand, Equation 4.8and Figure 28assume no formation damage in the horizontal well. A damage skin effect would require a longer section length (see Brown and Economides (1992) for a comprehensive treatment). In general, we may conclude that unfractured horizontal wells are not attractive in reservoirs where hydraulically fractured vertical wells have traditionally been successful. This implies that in such environments, horizontal wells themselves need to be fractured.

If a is approximately equal to r_{eH} (almost always true) and if reH reV, then Equation 3.8 has a much simpler approximation:

$$r'_{wD} x_f = \frac{L/4}{\left(\frac{I_{ani} h}{(I_{ani}+1) r_w}\right)^{I_{ani} h / L}} \quad \textbf{(3.11)}$$

Example: Horizontal Well Length vs. Fractured Vertical Well

Suppose that a reservoir has a permeability of 1 md, a thickness of 75 ft, and an Iani value of 3. Optimized hydraulic fracture design suggests that x_f should be 1500 ft and FCD = 1.8. If r_{eH} = 2980 and r_w = 0.328 ft, calculate the minimum horizontal well length required for equal well performance.

Solution:

The relative capacity parameter (a), from Equation 4.10 is equal to 0.87. From Figure27 r'_{wD} = 0.25.

Therefore, from Equation 1.11 and appropriate substitutions,

$$375 = \frac{L/4}{[171.5]^{225/L}} \quad \textbf{(3.12)}$$

and by trial and error, L = 2400 ft [732 m].

7.7 PSEUDO-STEADY STATE PRODUCTIVITY CACULATIONS

There are three methods available to calculate pseudo-steady state productivities of horizontal wells for single phase flow. In all these methods, the reservoir is assumed to be bounded in all directions and the horizontal well is located arbitrarily within a rectangular bounded drainage area.

The difference between the three methods is in their mathematical solution methods and the boundary conditions used. For e.g. the first method assumes a horizontal well as an infinite-conductivity well. The second method assumes a uniform flux boundary condition and the last method uses an approximate infinite conductivity solution where the constant wellbore pressure is estimated by averaging pressure values of the uniform-flux solution along the wellbore length.

Method I

For rectangular drainage areas with 2Xe/(2Ye)=1 to 20, Mutalik et al.[3] reported the shape factors and the corresponding equivalent skin factors for horizontal wells located at various positions within the drainage volume. The skin factors S_{cAh} for centrally located wells within drainage area with ratios of sides, 2Xe/(2Ye)=1, 2 and 5 are plotted in Figures 29 through 31. The following equation can be used to calculate the productivity of a horizontal well:

Where

$$J_h = \frac{q}{\bar{p}_R - p_{wf}} = \frac{0.007078\ kh/(\mu_0 B_0)}{\ln\left(\frac{r_e'}{\ }\right) - A' + s_f + s_m + s_{CA,h} - c' + Dq}$$

and

D = turbulence coefficient, 1/BOPD for oil and 1/MSCFD for gas

s_m = mechanical skin factor, dimensionless

s_f = skin factor of an infinite-conductivity, fully penetrating fracture of length, L

$s_f = -\ln[L/(4r_w)]$

$s_{CA,h}$ = shape-related skin factor

c' = shape factor conversion constant = 1.386

s_m here is calculated as $s_m = s\,(h/L)\sqrt{kh/kv}$ where s is the skin factor

By using figures 29 through 31 value of S_{cAh} is determined and knowing s_f and S_{cAh}, the productivity can be calculated.

Method II

In this method, a horizontal well problem is looked upon as a problem similar to that for a partially penetrating vertical well. If this partially penetrating vertical well problem is turned sideways, it results in a horizontal well problem. Babu and Odeh[12] derived the following equation for horizontal well pseudo-steady state productivity:

$$J_h = \frac{0.007078\,(2x_e)\sqrt{k_y k_v}/(\mu_o B_o)}{\ln(\sqrt{A_1}/r_w) + \ln C_H - 0.75 + s_R}$$

Where k_y is the horizontal permeability in the direction perpendicular to the wellbore. The value s_R accounts for the skin factor due to partial penetration of the horizontal well in the areal plane. $s_R=0$ when $L = 2x$. C_H is the shape factor. A_l is horizontal well drainage area in the vertical plane ($A_l = 2y_e h$). The values 2Xe and 2Ye are reservoir dimensions shown in Figure 29.

Calculation of $\ln C_H$

$$\ln C_H = 6.28\left(\frac{2y_e}{h}\right)\sqrt{\frac{k_v}{k_y}}\left[\frac{1}{3} - \left(\frac{y_w}{2y_e}\right) + \left(\frac{y_w}{2y_e}\right)^2\right] - \ln\left[\sin\left(180^\circ\frac{z_w}{h}\right)\right] - 0.5\ln\left[\left(\frac{2y_e}{h}\right)\sqrt{\frac{k_v}{k_y}}\right] - 1.088$$

Where z_w is the vertical distance between the horizontal well and the bottom boundary and as noted in Figure 29, y_e denotes the distance from the horizontal well to the closest boundary in the y direction.

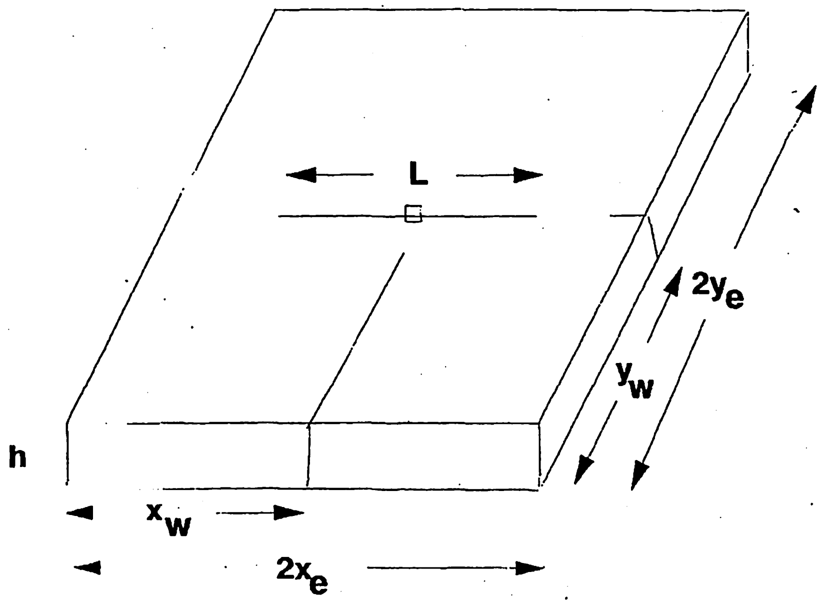


Fig 7.29: Horizontal Well in Rectangular Drainage volume

Calculation of s_R

As stated previously, $s_R = 0$ when $L = 2Xe$. If $L < 2Xe$, then the value of partial penetration skin factor s_R depends upon the following two conditions:

Case 1: $2y_e/\sqrt{k_y} \geq 1.5x_e/\sqrt{k_x} >> 0.75h/\sqrt{k_v}$

Case 2: $2x_e/\sqrt{k_x} \geq 2.66y_e/\sqrt{k_y} >> 1.33h/\sqrt{k_v}$

Case 1

Here, $s_R = PXYZ + PXY'$

The *PXYZ* Component

$$PXYZ = \left[\frac{2x_e}{L} - 1\right]\left[\ln\left(\frac{h}{r_w}\right) + 0.25\ln\left(\frac{k_y}{k_v}\right) - \ln\left(\sin\frac{180^\circ z_w}{h}\right) - 1.84\right]$$

The *PXY'* Component

$$PXY' = \left(\frac{2(2x_e)^2}{Lh}\sqrt{\frac{k_v}{k_x}}\right)\left[f(x) + 0.5\,\{f(y_1) - f(y_2)\}\right]$$

Where f represents a function. The terms in parenthesis after f are their arguments defined as

$$x = \frac{L}{4x_e},\quad y_1 = \frac{4x_w + L}{4x_e},\ \text{and}\ y_2 = \frac{4x_w - L}{4x_e}$$

Where x_w is the distance from the horizontal well mid-point to the closest boundary in the x direction. Additionally pressure computations are made at the mid-point along the well length and function f(x) is defined as

$$f(x) = -x\,[0.145 + \ln(x) - 0.137(x)^2]$$

The evaluation of $f(y_1)$ and $f(y_2)$ depends upon their arguments. If the argument, (y_1 or y_2)<= 1, the above equation is used by replacing x with y_1 or y_2 . On the other hand , if (y_1 or y_2)> 1 then the following equation can be used.

$$f(y) = (2 - y)\,[0.145 + \ln(2 - y) - 0.137(2 - y)^2]$$

where $y = y_1$ or y_2

Case 2

Here, $s_R = PXYZ + PY + PXY$

The *PXYZ* Component

This is calculated as before

The *PY* Component

$$PY = 6.28 \frac{(2x_e)^2}{2y_e h} \frac{\sqrt{k_y k_v}}{k_x} \left[\left\{ \frac{1}{3} - \left(\frac{x_w}{2x_e}\right) + \left(\frac{x_w}{2x_e}\right)^2 \right\} + \frac{L}{48x_e}\left(\frac{L}{2x_e} - 3\right) \right]$$

where x_w is the mid-point co-ordinate of the well.

The *PXY* Component

$$PXY = \left(\frac{2x_e}{L} - 1\right) \frac{6.28\,(2y_e)}{h} \sqrt{\frac{k_v}{k_y}} \left[\frac{1}{3} - \left(\frac{y_w}{2y_e}\right) + \left(\frac{y_w}{2y_e}\right)^2 \right]$$

$$\text{for } [\mathrm{Min}\,\{y_w, (2y_e - y_w)\} \geq 0.5y_e]$$

Method III

Kuchuk et al used an approximate infinite-conductivity solution, where the constant wellbore pressure is obtained by averaging pressure values of the uniform flux solution along the well length. Their productivity equation is expressed as

$$J_h = \frac{k_h h/(70.6\ \mu_o)}{F + (h/0.5L)\sqrt{k_h/k_v}\ s_x}$$

F is a dimensionless function that depends on $y_w/2y_e$, $x_w/2x_e$, $L/4\ x_e$ and $y_e/x_e\ \sqrt{k_x/k_y}$. Typical values of F are listed in table 2.

$\frac{y_e}{x_e}\sqrt{\frac{k_x}{k_y}}$	$y_w/(2y_e) = 0.50$, $x_w/(2x_e) = 0.50$ — $L/(4x_e)$ 0.1	0.2	0.3	0.4	0.5
0.25	3.80	2.11	1.09	0.48	0.26
0.50	3.25	1.87	1.12	0.69	0.52
1.00	3.62	2.30	1.60	1.21	1.05
2.00	4.66	3.34	2.65	2.25	2.09
4.00	6.75	5.44	4.74	4.35	4.19

	$y_w/(2y_e) = 0.25$, $x_w/(2x_e) = 0.50$ — 0.1	0.2	0.3	0.4	0.5
0.25	4.33	2.48	1.36	0.70	0.46
0.50	3.89	2.42	1.58	1.10	0.92
1.00	4.47	3.13	2.41	2.00	1.83
2.00	6.23	4.91	4.22	3.83	3.67
4.00	9.90	8.58	7.88	7.49	7.33

	$y_w/(2y_e) = 0.25$, $x_w/(2x_e) = 0.25$ — 0.05	0.1	0.15	0.2	0.25
0.25	9.08	7.48	6.43	5.65	5.05
0.50	6.97	5.56	4.71	4.12	3.71
1.00	6.91	5.54	4.76	4.24	3.90
2.00	8.38	7.02	6.26	5.76	5.44
4.00	11.97	10.61	9.85	9.36	9.04

	$y_w/(2y_e) = 0.50$, $x_w/(2x_e) = 0.25$ — 0.05	0.1	0.15	0.2	0.25
0.25	8.44	6.94	5.98	5.26	4.70
0.50	6.21	4.83	4.02	3.47	3.08
1.00	5.86	4.50	3.73	3.23	2.90
2.00	6.73	5.38	4.62	4.12	3.81
4.00	8.82	7.46	6.71	6.21	5.89

The value of s_x is calculated using the following equation.

$$s_x = \ln\left[\left(\frac{\pi r_w}{h}\right)\left(1 + \sqrt{\frac{k_v}{k_h}}\right)\sin\left(\frac{\pi z_w}{h}\right)\right] - \sqrt{\frac{k_h}{k_v}}\left(\frac{2h}{L}\right)\left[\frac{1}{3} - \left(\frac{z_w}{h}\right) + \left(\frac{z_w}{h}\right)^2\right]$$

OPTIMIZATION OF PRODUCTION THROUGH EXPANDABLE, INTELLIGENT MULTILATERAL WELLS

During the past decade, the oil and gas industry has implemented several new well completion technologies. Among these are expandable, multilateral, and intelligent well systems. These three technologies have each proven themselves beneficial because of their ability to reduce costs and/or increase production. The next logical step is to integrate all three of these technologies in a single well bore to achieve even greater well construction and production efficiencies. This article reviews the state of the art in expandable, multilateral and Intelligent Well Systems and explores the potential for production optimization when all three technologies are implemented in one well.

Expandable Systems[15]

Expandable metal technology has been applied in various industries for many years to form metal into fit-for-purpose shapes. It has been only a little over a decade since expandable metal technology was adapted to oilfield tubular products. Since then, expandable metal technology has been used in more than a thousand downhole applications. Most of the early wells that successfully employed this technology are in the former Soviet Union and Vietnam. Today, the technology is being used throughout the world to repair or seal worn and damaged pipe and to help operators construct deeper, slimmer wells that are more productive, yet use fewer casing sizes than larger wells.

Intelligent Well Systems[15]

Intelligent Well Systems offer a more flexible approach to the management of hydrocarbon assets. By combining real-time data monitoring with surface-controlled sliding sleeves, an operator can reduce or eliminate interventions and their associated risks, reduce production downtime, and lower overall well operating costs. The ability to control multiple production or injection intervals independently without intervention allows selective control in horizontal and extended reach, multilateral and subsea wells.

Interventions are not needed since downhole flow control devices can be actuated through remote control. These devices enable selective total shut-off or rate control of undesirable water or gas encroachment in a producing well, or total shut-off or injectivity rate control of a selected interval in an injection well.

In addition to the benefits of remote flow control, real-time monitoring of downhole pressure, temperature and flow allows for:

- Precise dynamic tubing pressure measurement at or near perforation depths
- Precise sandface pressure determination with no wellbore storage effects
- Selective interference and transient pressure testing.

Currently, intelligent well systems for remote control and permanent monitoring include:

- Hydraulically based system with electronic permanent downhole gauges
- hydraulically based system with fiber optic sensors
- All-electric intelligent completion system

Combining Expandable and Multilateral Technology

During 2001, the world's first TAML Level 6 re-formable junction was installed in conjunction with expandable screens in a North Sea well. To deliver 1500 ft (457 m) of a completed section in close proximity to the gas-oil contact (GOC), the operator had decided on a multilateral completion. A Level 6 FORMation junction was selected and the dual-lateral sections installed horizontally in the reservoir just below the GOC. The pre-formed leg section was then hydro-mechanically re-formed prior to cementing the junction and casing in place. Two 6-in. lateral legs were drilled and completed sequentially to provide a combined production interval of 2,600 ft (792 m) in an unconsolidated sandstone reservoir. By using an expandable screen, a 5-in. ID was achieved across the producing intervals. Installation of conventional sand screens would have produced a significant reduction in open inflow area, which would have compromised pressure management and productivity. The dual lateral enabled delivery of higher production rates at a lower pressure drawdown, thus reducing the well's susceptibility to gas coning.

The well's initial production exceeded predicted values. To date, the well has delivered about 30% more reserves than originally forecasted.

Combining Multilateral and Intelligent Well Systems

In March 2003, Baker Oil Tools installed a Level 3 Hook Hanger system in conjunction with an InForce IWS system in the Mukhaizna field, onshore Oman. A horizontal multilateral was chosen because the cost-effective method of completion would allow for commingled heavy oil production through an electric submersible PCP pump.The option to shut off production from the mainbore in the event of anticipated water breakthrough is achieved by closing the hydraulic sliding sleeve remotely from the surface. Once the water coning has dissipated, production from the lower leg can be initiated by opening the sliding sleeve, again from the surface. This capability reduces cost as it eliminates shut down of production from the lateral leg and rig down time associated with manipulation. It also reduces risk associated with intervention activities. To create the junction, the WindowMaster™ system was deployed and the 81/2-in. hole was drilled. The whipstock assembly was retrieved and the liner assembly with a bent sub, slotted liner and Hook Hanger were run into the well with the "hook" engaging the casing at the bottom of the casing exit window. In one trip, the payzone packer was inflated, the lateral diverter was released and the lower zone opened for production. The InForce IWS system was run with the submersible pump assembly and the hydraulic sliding sleeve was function tested. At a later date, production was initiated at the level expected

Combining the Three Technologies

In October 2002, CNOOC successfully completed an offshore Indonesia well that combined expandable, multilateral and an Intelligent Well System. Due to the limited number of well slots available on the platform, multilateral technology was selected to maximize the production of two oil zones with a single well. Expandable screens were selected, based on a one-trip installation, annular flow reduction, large inside diameter and a sand study. An Intelligent Well System was chosen to allow periodic shutoff of the upper lateral, with maximum return (production and recovery) and minimal total cost (capital and operating expenditures). After reaching TD, the drilling assembly was back reamed to the casing shoe, then run back to TD and back reamed out again. An open-ended stabilized assembly was then run into the open hole with a casing scraper. Care was taken to ensure wellbore stability before running in the expandable system. Subsequently, an assembly of blank pipe, expandable screen, isolation packers and liner hanger were successfully expanded (Figure 8.1). The results show the productivity index to be better than expected.

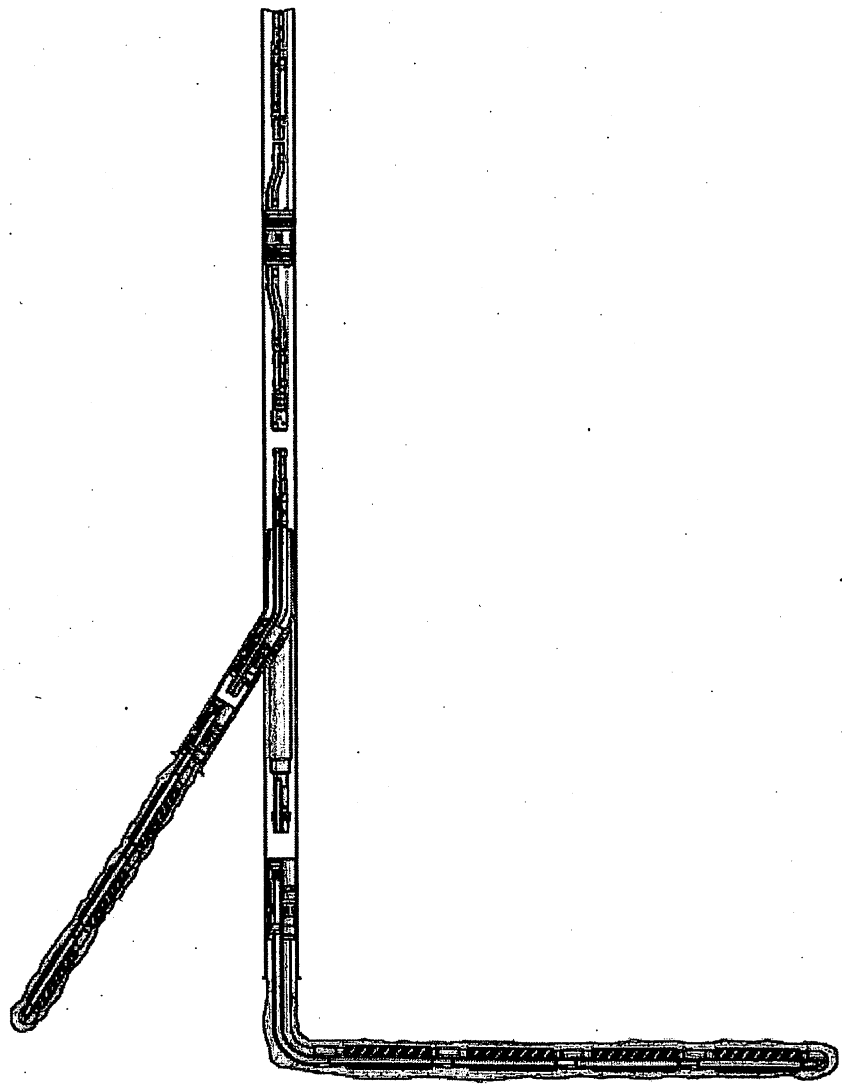


Fig 8.1: Combining expandable, multilateral and MIS technologies

9. Conclusion

The upstream oil industry being a high risk industry puts a great emphasis on "hitting paydirt" i.e. finding substantial reserves of oil & gas, which unfortunately is getting harder to locate day by day. Fortunately the industry has made great strides in the technological aspect. In the last century it was basically easy oil but lack of efficient technology.

Horizontal well and multilateral wells have become popular in the past decade with the stress on exploiting difficult to access & thin formations. Horizontal & Multilateral technology is an advanced technology that is taking the game further.

Horizontal & Multilateral technology is an expensive technology & hence depends on the proper integration of geologic, reservoir, drilling, completion & economic data. Thus the problem needs to be understood clearly for the successful implementation of the technology. That is the geological & reservoir aspects must be thoroughly studied before the decision to drill is taken. For example the effect of the ratio of vertical to horizontal permeability, the well length & the payzone thickness for a given play needs to be adequately dealt to identify the suitable completion scheme, based on the simulation of well performance for different completion techniques.

The completion of these non-conventional wells is a challenge to any completion team. Therefore the completion team must include reservoir engineers & geo-mechanics experts apart from the completion engineers, in order to select the appropiate completion scheme that takes into account factors such as formation integrity, completion longevity & pressure integrity at the junctions as well as economics.

Depending on the completion scheme, a certain bore dia for the drainhole to be drilled is obtained. The build up rates & the tangent sections are then determined depending on the lateral dia & True vertical depth. The drilling of these wells is laden with uncertainties, which is why the drilling engineers must be given the maximum tolerances.

The two most important challenges for drilling non- conventional wells are torque & drag and hole cleaning. Based on these factors the tubulars & mud system for the wells are selected.

Well eccentricity plays an important role not only in drilling but also on the performance of non-conventional wells. The productivity of horizontal wells can be calculated based on steady states calculations & pseudo steady state calculations. The productivity mainly depend the well length, the thickness and the reservoir anisotropy.

Prediction of horizontal well performance has been achieved using a software for a real life field. Also a history matching for multilateral well has been illustrated for a real field using another software.

The softwares used are JTI Horizontal & JTI Multilateral. It is observed from the results of the software runs that productivity increases with the acreage, well length and permeability ratio.

Thus the planning of Horizontal & Multilateral wells is a seamless integration of reservoir, geological, completion & driliing aspects.

ANNEXURE

1. HORIZONTAL WELL PERFORMANCE BY SOFTWARE

We used JTI Horizontal version 6.1 for predicting the well performance. The input parameters were taken from the Bakken Field after going through its case history. The performance has been predicted for a single horizontal oil well.

The input parameters were:

Reservoir pressure= 4400 psi
Bottom hole flowing pressure= 4360 psi
Maximum allowable well rate= 10000 BOPD
Economic limit= 10 BOPD
Well length= 4000 ft
Mechanical skin factor= 0
Wellbore radius= 3.1 inch
Viscosity of oil= 0.7 cp
Formation volume factor of oil= 1.2 RB/STB
Reservoir temp= 190 F
Permeability ratio= 0.1
Permeability= 0.5 md
Payzone thickness= 15 ft
Area= 1280 acres
Water saturation= 0.25
Porosity= 0.12

The following results were obtained:

JTI.HORIZONTAL - Version 6.1(Aug 1999)
Single Well Analytical Rate Forecast Program

Echo of Input Data

WELL DATA

Case Name	: Bakken Horizontal
Date	: 04/26/2007
Time	: 23:49:17.48
Well Type	: H
Oil or Gas	: O
Forecast Type	: RATE
Solution Type	: ICS
Unit Type	: OILFIELD
Well Radius	: 3.100 in
Horizontal Length	: 4000. ft
Mechanical Skin Factor	: 0.00
BHFP	: 4360. psia
Well Allowable	: 30000.00 BOPD
Economic Limit	: 10.00 BOPD

RESERVOIR DATA

Drainage Area	: 1280. acres
Xe/Ye Ratio	: 1.0

Net Pay Thickness	:	15. ft
Porosity	:	0.120
Permeability	:	0.500 md
kv/kh Ratio	:	0.10
Reservoir Pressure	:	4400. psia
Water Saturation	:	0.250
Oil Viscosity	:	0.70 cp
Oil FVF	:	1.20 RB/STB
Total Compressibility	:	0.250E-04 1/psi
Decline Exponent	:	1.00
Turbulence Coefficient	:	Ignored

JTI.HORIZONTAL - Version 6.1 (Oct 1998)

Single Well Analytical Rate Forecast Program

DIAGNOSTIC CALCULATIONS

Case Name Bakken Horizontal

Original Oil in Place 11.17 MMBO

Decline Coefficient,Di 0.07 1/year

0.00020 1/day

Harmonic Decline

Time to Pseudo Steady State 3681.3 Days

Effective Drainage Radius 4213. feet

Drainage Area is 7467. feet long by 7467. feet wide

Permeability/Viscosity Ratio 0.23 md/cp

** k/u should be greater than 0.1 **

Shape Related Skin Factor, Sca -0.1

Total Effective Skin Factor -8.3

Effective Wellbore Radius 946.3 feet

Dimensionless Length 42.2

** LD should be between 1 and 55 **

L/2Xe Ratio 0.5

** L/2Xe should be less than 0.8 **

BACKPRESSURE CHANGES

From 4360. psia to 2650. psia at 30. days

From 2650. psia to 2350. psia at 426. days

TIME DAYS	TIME YEARS	CUM PRODN MSTB	REC %	AVG RATE STB/MO	AVG RATE BOPD
30.0	0.08	0.45	0.0	423.	BK PRESS CHG
60.9	0.17	20.16	0.2	17739.	583.
91.3	0.25	29.87	0.3	9708.	319.
121.7	0.33	37.76	0.3	7893.	259.
152.2	0.42	44.70	0.4	6941.	228.
182.6	0.50	51.02	0.5	6318.	208.
213.1	0.58	56.88	0.5	5863.	193.
243.5	0.67	62.40	0.6	5512.	181.
273.9	0.75	67.62	0.6	5227.	172.
304.4	0.83	72.61	0.6	4985.	164.
334.8	0.92	77.39	0.7	4785.	157.
365.2	1.00	82.01	0.7	4613.	152.
395.7	1.08	86.46	0.8	4455.	146.
426.0	1.17	90.76	0.8	4315.	BK PRESS CHG
456.6	1.25	98.37	0.9	7249.	238.
487.0	1.33	104.14	0.9	5765.	189.
517.4	1.42	109.48	1.0	5339.	175.
547.9	1.50	114.56	1.0	5084.	167.
578.3	1.58	119.44	1.1	4885.	160.
608.7	1.67	124.18	1.1	4732.	155.
639.2	1.75	128.78	1.2	4604.	151.
669.6	1.83	133.26	1.2	4482.	147.
700.1	1.92	137.64	1.2	4377.	144.

730.5	2.00	141.92	1.3	4277.	141.
760.9	2.08	146.11	1.3	4196.	138.
791.4	2.17	150.23	1.3	4119.	135.
821.8	2.25	154.27	1.4	4042.	133.
852.2	2.33	158.25	1,4	3978.	131.
882.7	2.42	162.17	1.5	3915.	129.
913.1	2.50	166.02	1.5	3852.	127.
943.6	2.58	169.80	1.5	3786.	124.
974.0	2.67	173.55	1.6	3742.	123.
1004.4	2.75	177.24	1.6	3690.	121.
1034.9	2.83	180.88	1.6	3645.	120.
1065.3	2.92	184.48	1.7	3598.	118.
1095.8	3.00	188.04	1.7	3559.	117.
1126.2	3.08	191.55	1.7	3512.	115.
1156.6	3.17	195.01	1.7	3456.	114.
1187.1	3.25	198.45	1.8	3448.	113.
1217.5	3.33	201.85	1.8	3399.	112.
1247.9	3.42	205.22	1.8	3363.	110.
1278.4	3.50	208.55	1.9	3330.	109.
1308.8	3.58	211.84	1.9	3297.	108.
1339.2	3.67	215.10	1.9	3257.	107.
1369.7	3.75	218.34	2.0	3244.	107.
1400.1	3.83	221.55	2.0	3206.	105.
1430.6	3.92	224.73	2.0	3179.	104.
1461.0	4.00	227.88	2.0	3150.	103.
1491.4	4.08	231.00	2.1	3124.	103.
1521.9	4.17	234.10	2.1	3097.	102.
1552.3	4.25	237.16	2.1	3061.	101.
1582.7	4.33	240.21	2.2	3048.	100.
1613.2	4.42	243.23	2.2	3022.	99.
1643.6	4.50	246.24	2.2	3006.	99.

1674.1	4.58	249.23	2.2	2993.	98.
1704.5	4.67	252.17	2.3	2939.	97.
1734.9	4.75	255.10	2.3	2933.	96.
1765.4	4.83	258.02	2.3	2912.	96.
1795.8	4.92	260.90	2.3	2880.	95.
1826.2	5.00	263.76	2.4	2868.	94.
2008.9	5.50	280.53	2.5	2794.	92.
2191.5	6.00	296.67	2.7	2691.	88.
2374.1	6.50	312.20	2.8	2588.	85.
2556.7	7.00	327.17	2.9	2495.	82.
2739.4	7.50	341.61	3.1	2407.	79.
2922.0	8.00	355.55	3.2	2323.	76.
3104.6	8.50	369.01	3.3	2244.	74.
3287.2	9.00	382.02	3.4	2167.	71.
3469.9	9.50	394.58	3.5	2094.	69.
3652.5	10.00	406.73	3.6	2024.	66.
3835.1	10.50	418.43	3.7	1950.	64.
4017.7	11.00	429.71	3.8	1880.	62.
4200.4	11.50	440.61	3.9	1817.	60.
4383.0	12.00	451.15	4.0	1757.	58.
4565.6	12.50	461.37	4.1	1702.	56.
4748.2	13.00	471.26	4.2	1650.	54.
4930.9	13.50	480.87	4.3	1601.	53.
5113.5	14.00	490.19	4.4	1554.	51.
5296.1	14.50	499.26	4.5	1511.	50.
5478.8	15.00	508.08	4.5	1470.	48.
5661.4	15.50	516.66	4.6	1431.	47.
5844.0	16.00	525.02	4.7	1394.	46.
6026.6	16.50	533.17	4.8	1358.	45.
6209.2	17.00	541.12	4.8	1325.	44.
6391.9	17.50	548.88	4.9	1293.	42.

6574.5	18.00	556.46	5.0	1263.	41.
6757.1	18.50	563.86	5.0	1234.	41.
6939.8	19.00	571.10	5.1	1206.	40.
7122.4	19.50	578.18	5.2	1180.	39.
7305.0	20.00	585.11	5.2	1155.	38.
7487.6	20.50	591.89	5.3	1130.	37.
7670.2	21.00	598.53	5.4	1107.	36.
7852.9	21.50	605.04	5.4	1085.	36.
8035.5	22.00	611.43	5.5	1064.	35.
8218.1	22.50	617.68	5.5	1043.	34.
8400.8	23.00	623.82	5.6	1023.	34.
8583.4	23.50	629.85	5.6	1004.	33.
8766.0	24.00	635.76	5.7	986.	32.
8948.6	24.50	641.57	5.7	968.	32.
9131.2	25.00	647.27	5.8	951.	31.
9313.9	25.50	652.88	5.8	934.	31.
9496.5	26.00	658.39	5.9	919.	30.
9679.1	26.50	663.81	5.9	903.	30.
9861.8	27.00	669.14	6.0	888.	29.
10044.4	27.50	674.38	6.0	874.	29.
10227.0	28.00	679.54	6.1	860.	28.
10409.6	28.50	684.62	6.1	846.	28.
10592.2	29.00	689.62	6.2	833.	27.
10774.9	29.50	694.54	6.2	821.	27.
10957.5	30.00	699.39	6.3	808.	27.
11140.1	30.50	704.17	6.3	796.	26.
11322.7	31.00	708.88	6.3	785.	26.
11505.4	31.50	713.52	6.4	774.	25.
11688.0	32.00	718.10	6.4	763.	25.
11870.6	32.50	722.61	6.5	752.	25.
12053.2	33.00	727.06	6.5	742.	24.

12235.9	33.50	731.45	6.5	732.	24.
12418.5	34.00	735.78	6.6	722.	24.
12601.1	34.50	740.05	6.6	712.	23.
12783.7	35.00	744.27	6.7	703.	23.
12966.4	35.50	748.43	6.7	694.	23.
13149.0	36.00	752.54	6.7	685.	23.
13331.6	36.50	756.60	6.8	676.	22.
13514.2	37.00	760.61	6.8	668.	22.
13696.9	37.50	764.57	6.8	660.	22.
13879.5	38.00	768.48	6.9	652.	21.
14062.1	38.50	772.34	6.9	644.	21.
14244.7	39.00	776.16	6.9	636.	21.
14427.4	39.50	779.94	7.0	629.	21.
14610.0	40.00	783.67	7.0	622.	20.
14792.6	40.50	787.35	7.0	615.	20.
14975.2	41.00	791.00	7.1	608.	20.
15157.9	41.50	794.61	7.1	601.	20.
15340.5	42.00	798.17	7.1	594.	20.
15523.1	42.50	801.70	7.2	588.	19.
15705.7	43.00	805.19	7.2	582.	19.
15888.4	43.50	808.64	7.2	575.	19.
16071.0	44.00	812.06	7.3	569.	19.
16253.6	44.50	815.44	7.3	563.	19.
16436.2	45.00	818.78	7.3	557.	18.
16618.9	45.50	822.09	7.4	552.	18.
16801.5	46.00	825.37	7.4	546.	18.
16984.1	46.50	828.61	7.4	541.	18.
17166.7	47.00	831.83	7.4	535.	18.
17349.4	47.50	835.01	7.5	530.	17.
17532.0	48.00	838.16	7.5	525.	17.
17714.6	48.50	841.28	7.5	520.	17.

17897.2	49.00	844.37	7.6	515.	17.
18079.9	49.50	847.43	7.6	510.	17.
18262.5	50.00	850.46	7.6	505.	17.
18445.1	50.50	853.46	7.6	501.	16.
18627.7	51.00	856.44	7.7	496.	16.
18810.4	51.50	859.38	7.7	491.	16.
18993.0	52.00	862.31	7.7	487.	16.
19175.6	52.50	865.20	7.7	483.	16.
19358.2	53.00	868.07	7.8	478.	16.
19540.9	53.50	870.92	7.8	474.	16.
19723.5	54.00	873.74	7.8	470.	15.
19906.1	54.50	876.53	7.8	466.	15.
20088.7	55.00	879.30	7.9	462.	15.
20271.4	55.50	882.05	7.9	458.	15.
20454.0	56.00	884.78	7.9	454.	15.
20636.6	56.50	887.48	7.9	450.	15.
20819.2	57.00	890.16	8.0	447.	15.
21001.9	57.50	892.82	8.0	443.	15.
21184.5	58.00	895.45	8.0	439.	14.
21367.1	58.50	898.07	8.0	436.	14.
21549.7	59.00	900.66	8.1	432.	14.
21732.4	59.50	903.23	8.1	429.	14.
21915.0	60.00	905.79	8.1	425.	14.
22097.6	60.50	908.32	8.1	422.	14.
22280.2	61.00	910.83	8.2	419.	14.
22462.9	61.50	913.33	8.2	416.	14.
22645.5	62.00	915.80	8.2	412.	14.
22828.1	62.50	918.26	8.2	409.	13.
23010.7	63.00	920.70	8.2	406.	13.
23193.4	63.50	923.11	8.3	403.	13.
23376.0	64.00	925.52	8.3	400.	13.

23558.6	64.50	927.90	8.3	397.	13.
23741.2	65.00	930.27	8.3	394.	13.
23923.9	65.50	932.61	8.3	391.	13.
24106.5	66.00	934.95	8.4	389.	13.
24289.1	66.50	937.26	8.4	386.	13.
24471.7	67.00	939.56	8.4	383.	13.
24654.4	67.50	941.84	8.4	380.	12.
24837.0	68.00	944.11	8.5	378.	12.
25019.6	68.50	946.36	8.5	375.	12.
25202.2	69.00	948.60	8.5	373.	12.
25384.9	69.50	950.82	8.5	370.	12.
25567.5	70.00	953.02	8.5	367.	12.
25750.1	70.50	955.21	8.6	365.	12.
25932.7	71.00	957.39	8.6	363.	12.
26115.4	71.50	959.55	8.6	360.	12.
26298.0	72.00	961.69	8.6	358.	12.
26480.6	72.50	963.83	8.6	355.	12.
26663.2	73.00	965.94	8.6	353.	12.
26845.9	73.50	968.05	8.7	351.	12.
27028.5	74.00	970.14	8.7	348.	11.
27211.1	74.50	972.22	8.7	346.	11.
27393.7	75.00	974.28	8.7	344.	11.

Transient results:

TRANSIENT ANALYTICAL SOLUTION
(WITHOUT ANY BACK-PRESSURE CHANGES)

DIMENSIONLESS PARAMETERS AT DIFFERENT TIME STEPS

TD	TDA	QD	QDI
0.189E-03	0.135E-04	0.182E+02	0.437E-02
0.377E-03	0.271E-04	0.147E+02	0.743E-02
0.113E-01	0.812E-03	0.342E+01	0.670E-01
0.115E-01	0.824E-03	0.340E+01	0.675E-01
0.230E-01	0.165E-02	0.256E+01	0.101E+00
0.345E-01	0.247E-02	0.219E+01	0.128E+00
0.459E-01	0.330E-02	0.196E+01	0.152E+00
0.574E-01	0.412E-02	0.181E+01	0.173E+00
0.689E-01	0.494E-02	0.169E+01	0.193E+00
0.804E-01	0.577E-02	0.159E+01	0.212E+00
0.919E-01	0.659E-02	0.152E+01	0.230E+00
0.103E+00	0.742E-02	0.145E+01	0.247E+00
0.115E+00	0.824E-02	0.140E+01	0.263E+00
0.126E+00	0.906E-02	0.135E+01	0.279E+00
0.138E+00	0.989E-02	0.130E+01	0.294E+00
0.149E+00	0.107E-01	0.126E+01	0.309E+00
0.161E+00	0.115E-01	0.123E+01	0.323E+00
0.161E+00	0.115E-01	0.123E+01	0.323E+00
0.172E+00	0.124E-01	0.120E+01	0.337E+00
0.184E+00	0.132E-01	0.117E+01	0.351E+00
0.195E+00	0.140E-01	0.114E+01	0.364E+00
0.207E+00	0.148E-01	0.112E+01	0.377E+00

0.218E+00	0.157E-01	0.110E+01	0.390E+00
0.230E+00	0.165E-01	0.108E+01	0.402E+00
0.241E+00	0.173E-01	0.106E+01	0.415E+00
0.253E+00	0.181E-01	0.104E+01	0.427E+00
0.264E+00	0.190E-01	0.102E+01	0.438E+00
0.276E+00	0.198E-01	0.100E+01	0.450E+00
0.287E+00	0.206E-01	0.989E+00	0.461E+00
0.299E+00	0.214E-01	0.975E+00	0.473E+00
0.310E+00	0.222E-01	0.962E+00	0.484E+00
0.322E+00	0.231E-01	0.949E+00	0.495E+00
0.333E+00	0.239E-01	0.936E+00	0.506E+00
0.345E+00	0.247E-01	0.924E+00	0.516E+00
0.356E+00	0.255E-01	0.913E+00	0.527E+00
0.368E+00	0.264E-01	0.902E+00	0.537E+00
0.379E+00	0.272E-01	0.892E+00	0.548E+00
0.391E+00	0.280E-01	0.882E+00	0.558E+00
0.402E+00	0.288E-01	0.873E+00	0.568E+00
0.414E+00	0.297E-01	0.864E+00	0.578E+00
0.425E+00	0.305E-01	0.854E+00	0.588E+00
0.436E+00	0.313E-01	0.846E+00	0.597E+00
0.448E+00	0.321E-01	0.838E+00	0.607E+00
0.459E+00	0.330E-01	0.830E+00	0.617E+00
0.471E+00	0.338E-01	0.822E+00	0.626E+00
0.482E+00	0.346E-01	0.815E+00	0.635E+00
0.494E+00	0.354E-01	0.808E+00	0.645E+00
0.505E+00	0.363E-01	0.801E+00	0.654E+00
0.517E+00	0.371E-01	0.794E+00	0.663E+00
0.528E+00	0.379E-01	0.787E+00	0.672E+00
0.540E+00	0.387E-01	0.781E+00	0.681E+00
0.551E+00	0.396E-01	0.774E+00	0.690E+00
0.563E+00	0.404E-01	0.768E+00	0.699E+00

0.574E+00	0.412E-01	0.762E+00	0.708E+00
0.586E+00	0.420E-01	0.756E+00	0.716E+00
0.597E+00	0.429E-01	0.750E+00	0.725E+00
0.609E+00	0.437E-01	0.745E+00	0.734E+00
0.620E+00	0.445E-01	0.740E+00	0.742E+00
0.632E+00	0.453E-01	0.734E+00	0.751E+00
0.643E+00	0.461E-01	0.729E+00	0.759E+00
0.655E+00	0.470E-01	0.724E+00	0.767E+00
0.666E+00	0.478E-01	0.718E+00	0.776E+00
0.678E+00	0.486E-01	0.713E+00	0.784E+00
0.689E+00	0.494E-01	0.708E+00	0.792E+00
0.758E+00	0.544E-01	0.680E+00	0.840E+00
0.827E+00	0.593E-01	0.654E+00	0.886E+00
0.896E+00	0.643E-01	0.630E+00	0.931E+00
0.965E+00	0.692E-01	0.608E+00	0.973E+00
0.103E+01	0.742E-01	0.586E+00	0.101E+01
0.110E+01	0.791E-01	0.566E+00	0.105E+01
0.117E+01	0.841E-01	0.547E+00	0.109E+01
0.124E+01	0.890E-01	0.528E+00	0.113E+01
0.131E+01	0.939E-01	0.510E+00	0.117E+01
0.138E+01	0.989E-01	0.493E+00	0.120E+01
0.139E+01	0.997E-01	0.491E+00	0.121E+01

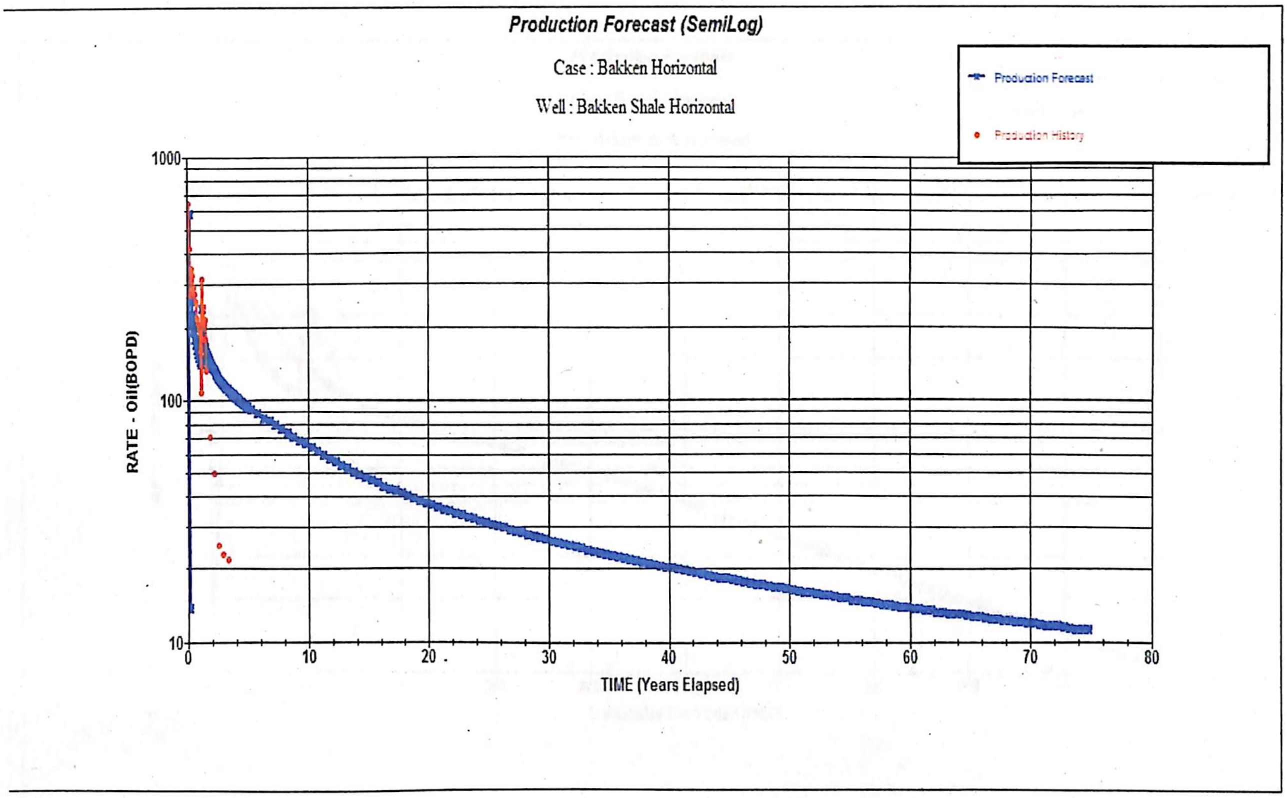
TRANSIENT RATE FORECAST

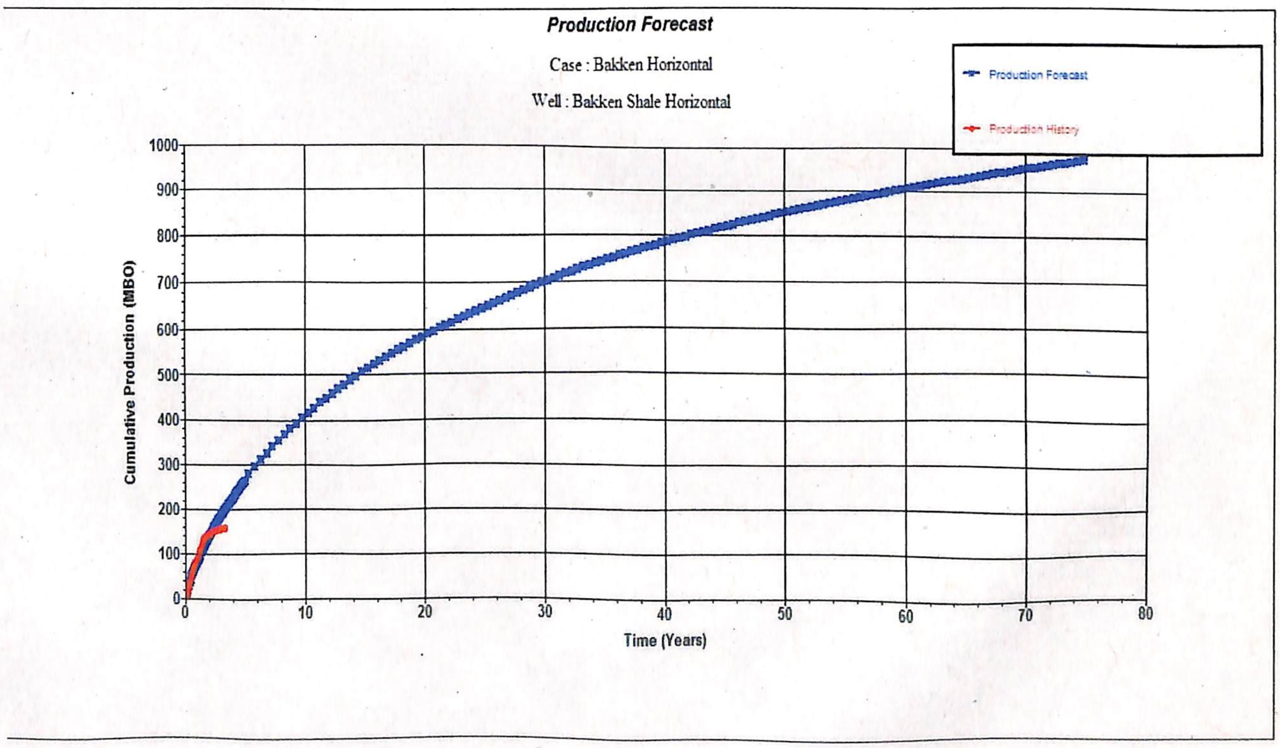
Time Rate

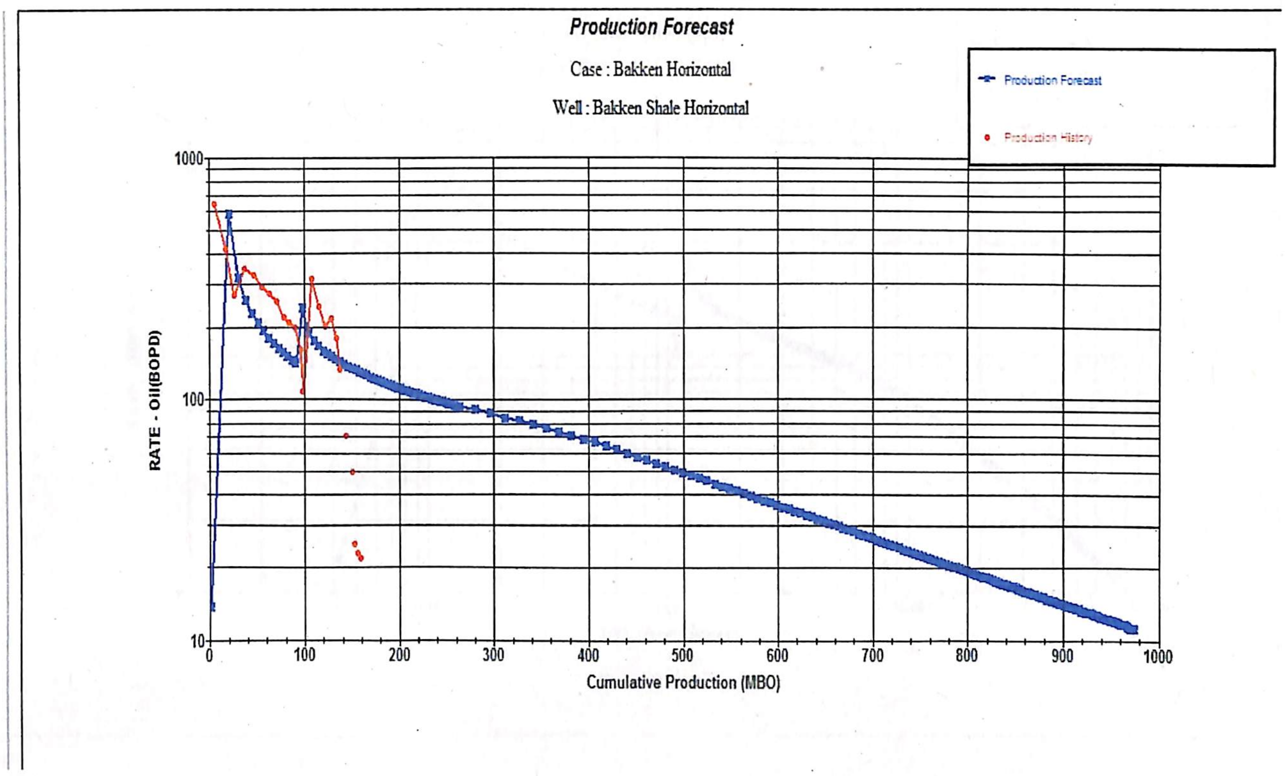
Days	STB/D
0.50	46.
1.00	37.
30.00	9.
30.44	9.
60.87	6.
91.31	6.
121.75	5.
152.19	5.
182.62	4.
213.06	4.
243.50	4.
273.94	4.
304.37	4.
334.81	3.
365.25	3.
395.69	3.
426.00	3.
426.12	3.
456.56	3.
487.00	3.
517.44	3.
547.87	3.
578.31	3.
608.75	3.
639.19	3.
669.62	3.
700.06	3.
730.50	3.

760.94	3.
791.37	2.
821.81	2.
852.25	2.
882.69	2.
913.12	2.
943.56	2.
974.00	2.
1004.44	2.
1034.88	2.
1065.31	2.
1095.75	2.
1126.19	2.
1156.62	2.
1187.06	2.
1217.50	2.
1247.94	2.
1278.37	2.
1308.81	2.
1339.25	2.
1369.69	2.
1400.12	2.
1430.56	2.
1461.00	2.
1491.44	2.
1521.87	2.
1552.31	2.
1582.75	2.
1613.19	2.
1643.62	2.
1674.06	2.

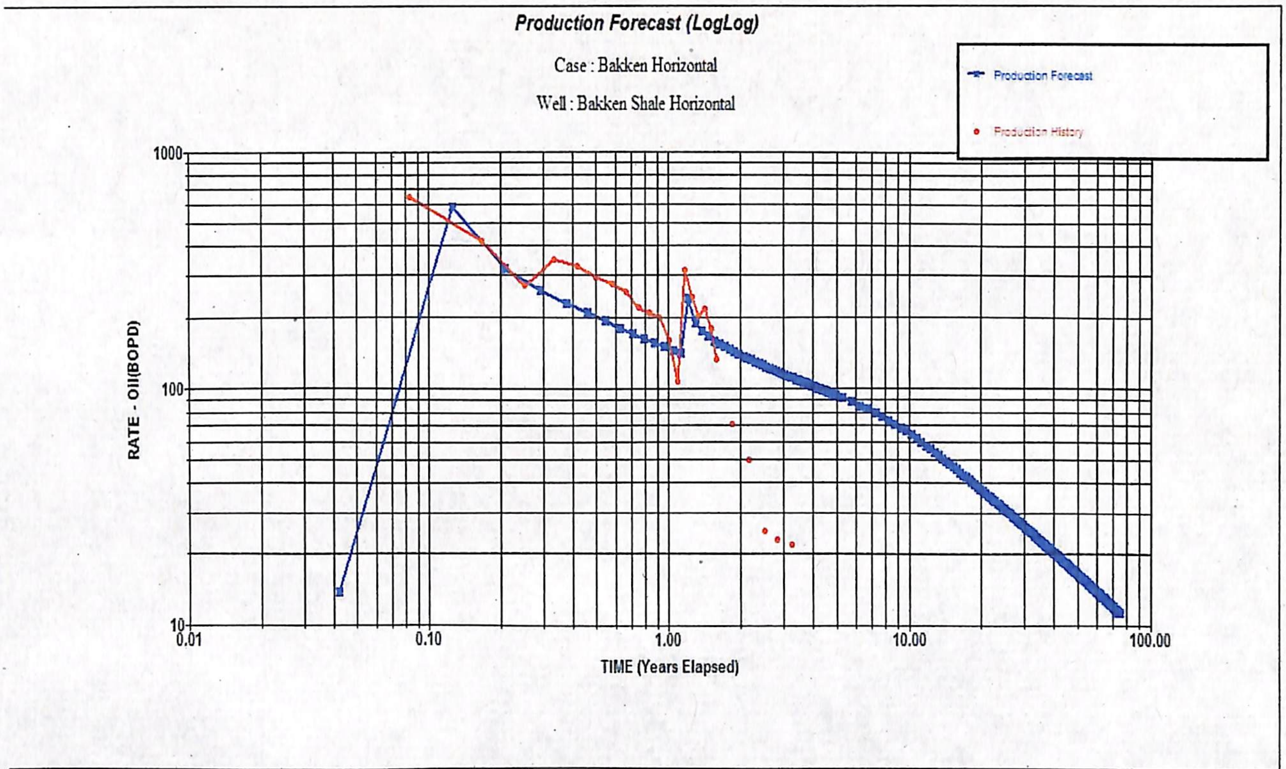
1704.50	2.
1734.94	2.
1765.37	2.
1795.81	2.
1826.25	2.
2008.87	2.
2191.50	2.
2374.12	2.
2556.75	2.
2739.38	1.
2922.00	1.
3104.62	1.
3287.25	1.
3469.88	1.
3652.50	1.
3681.29	1.

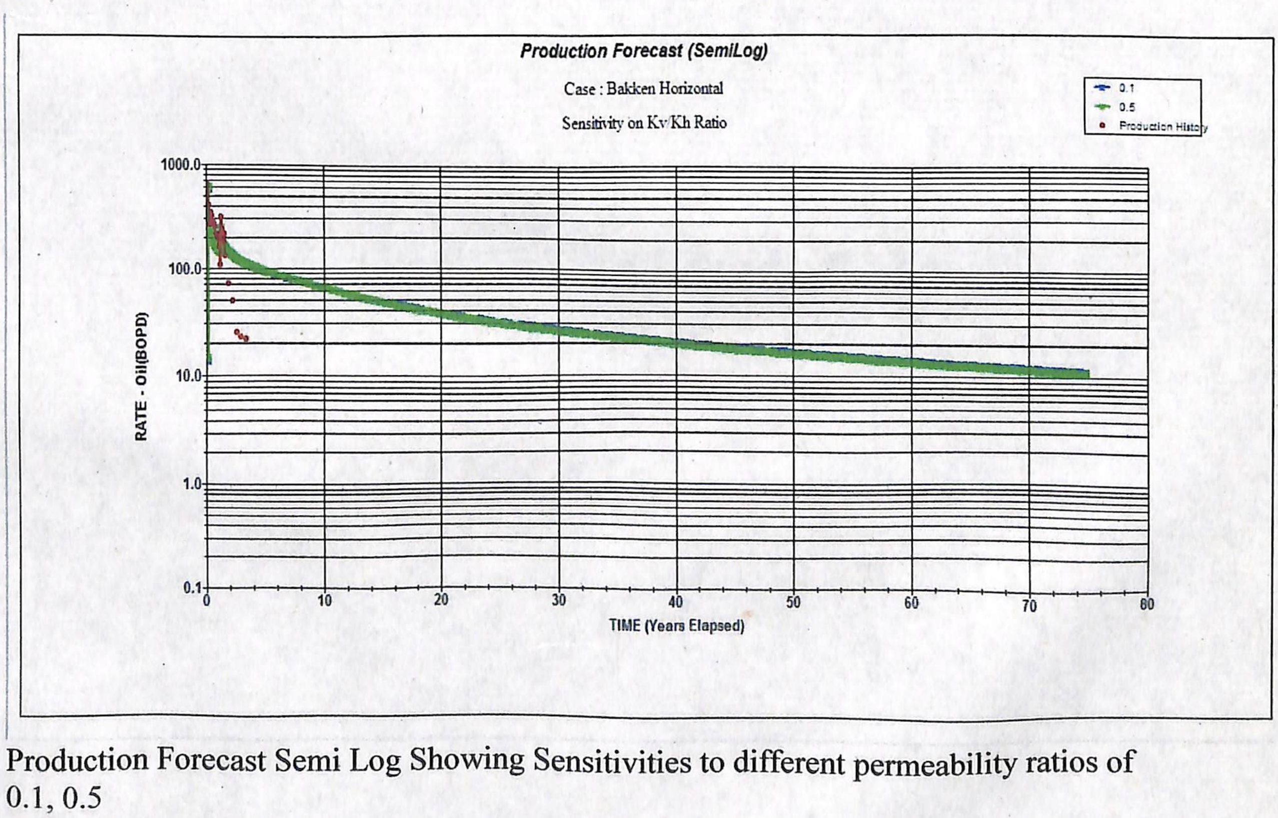

Production Forecast (SemiLog)
Case : Bakken Horizontal
Well : Bakken Shale Horizontal
Production Forecast
Production History
RATE - Oil(BOPD)
1000
100
10
0
10
20
30
40
50
60
70
80
TIME (Years Elapsed)


Production Forecast
Case : Bakken Horizontal
Well : Bakken Shale Horizontal
Production Forecast
Production History
Cumulative Production (MBO)
1000
900
800
700
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
80
Time (Years)

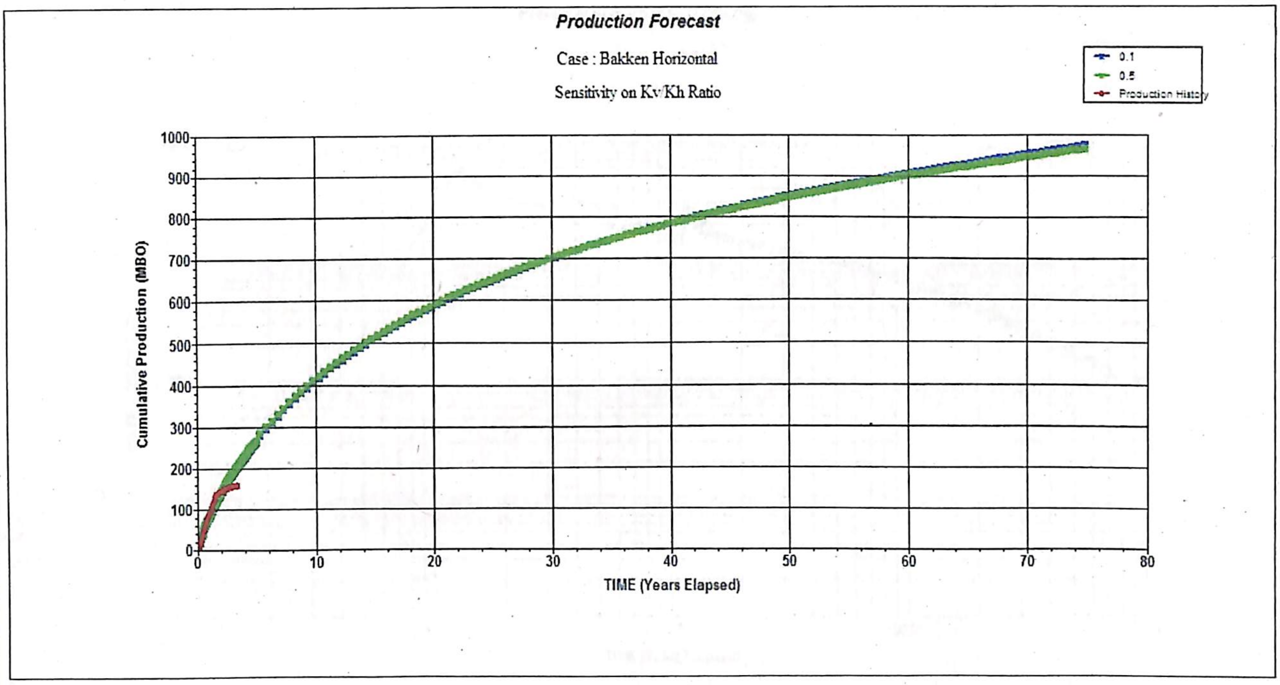


Production Forecast
Case : Bakken Horizontal
Well : Bakken Shale Horizontal
Production Forecast
Production History
RATE - Oil(BOPD)
1000
100
10
0
100
200
300
400
500
600
700
800
900
1000
Cumulative Production (MBO)

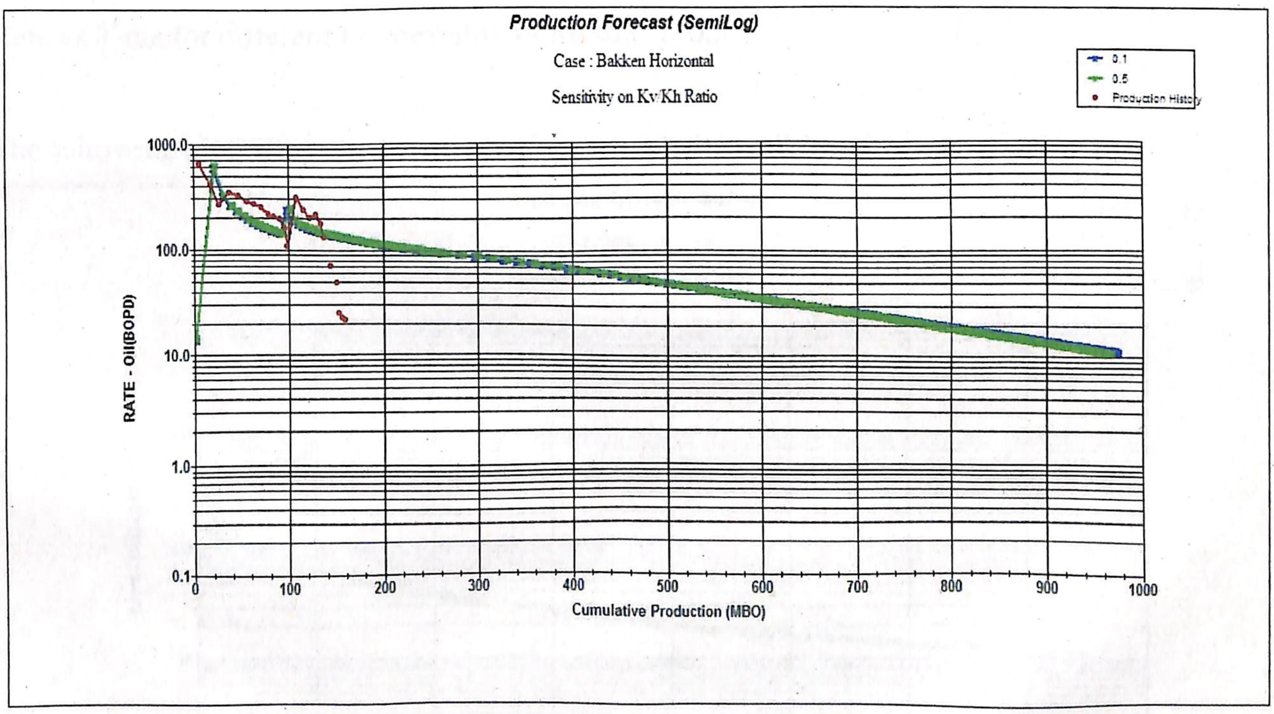




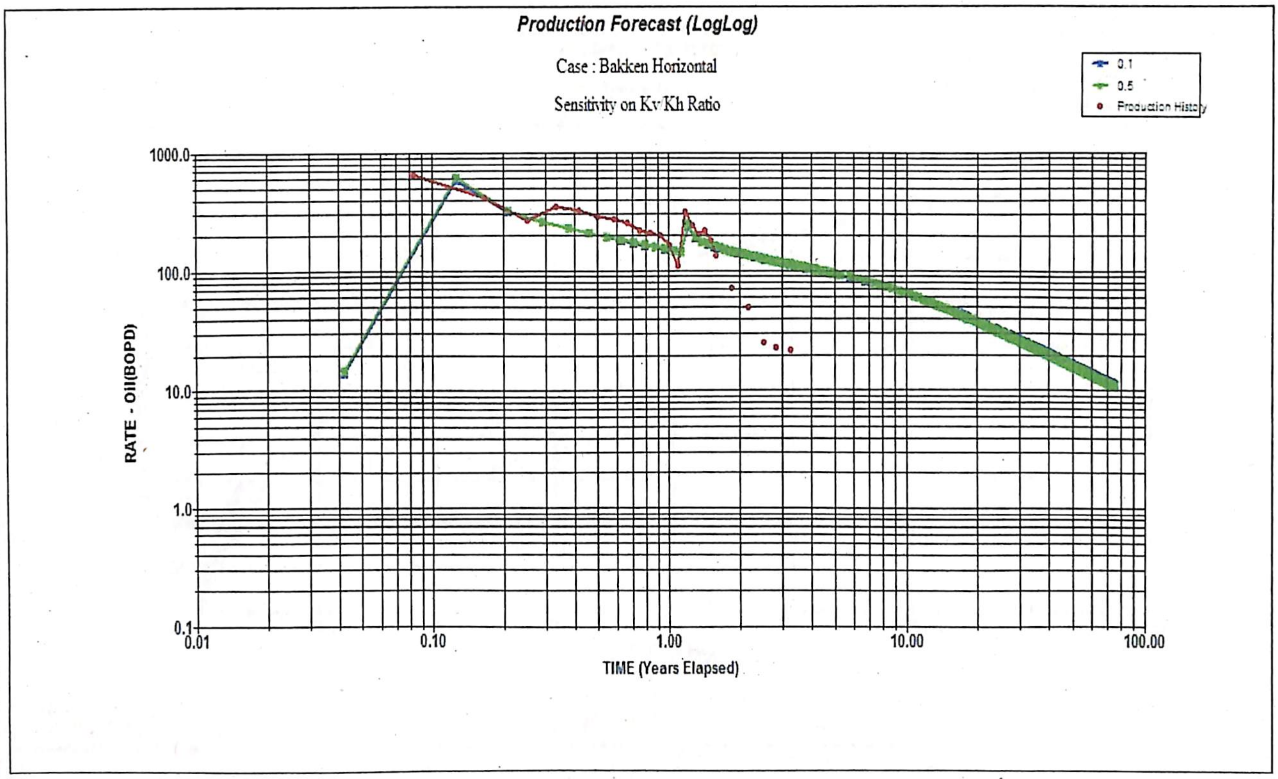
Production Forecast Semi Log Showing Sensitivities to different permeability ratios of 0.1, 0.5



Cumulative production vs Time for different Permeability ratios of 0.1, 0.5

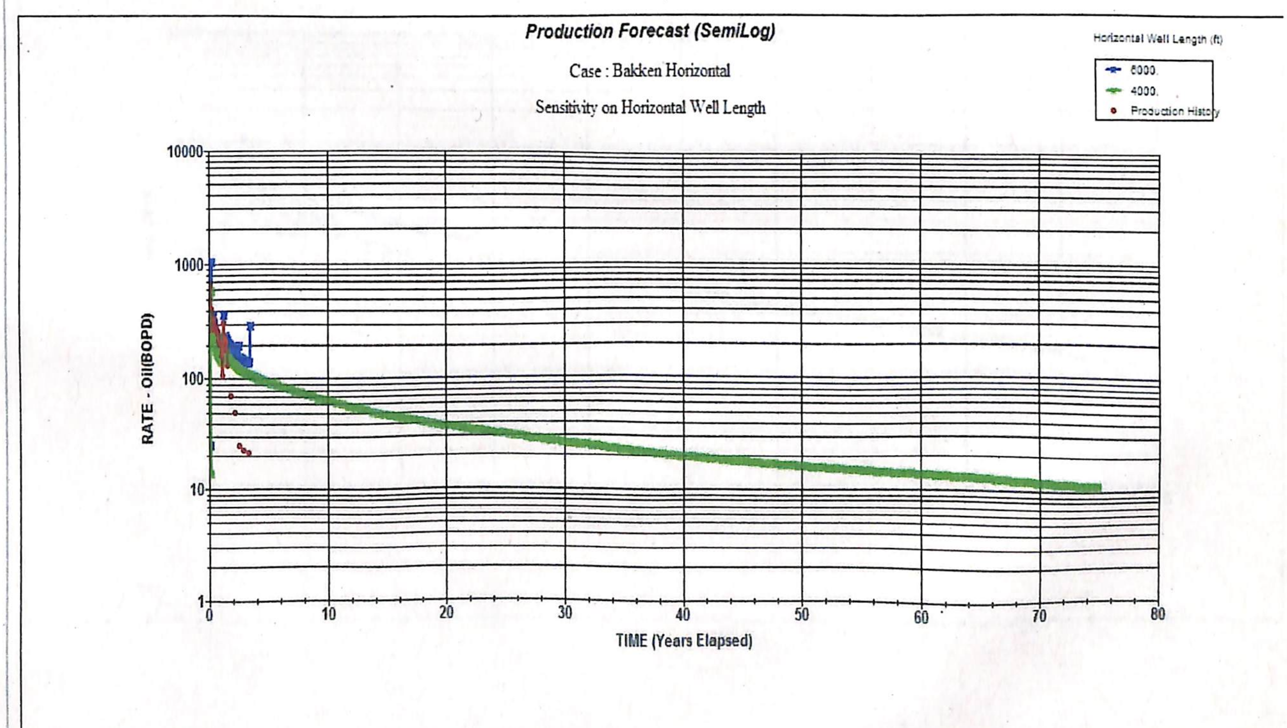


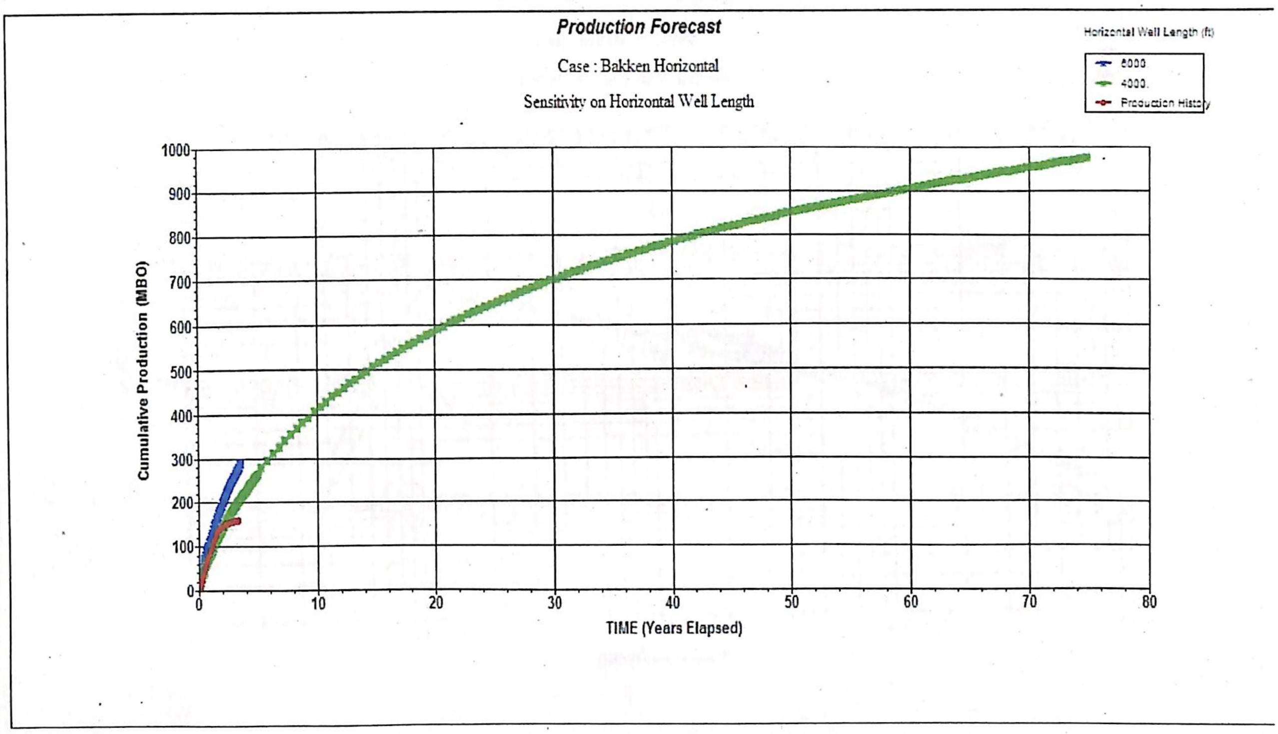
Rate vs Cumulative production for different Permeability ratios of 0.1, 0.5



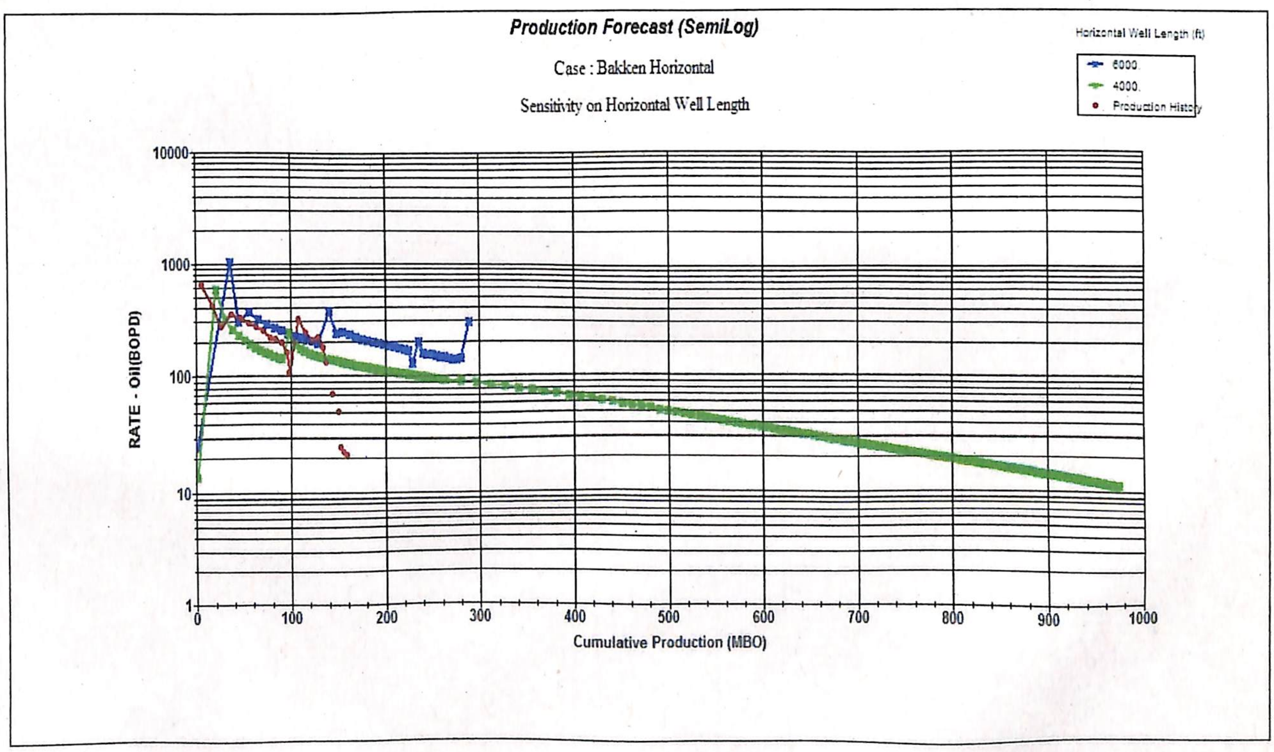
Rate vs Time for different Permeability ratios of 0.1, 0.5

The following plots illustrate the effect of increasing the well length

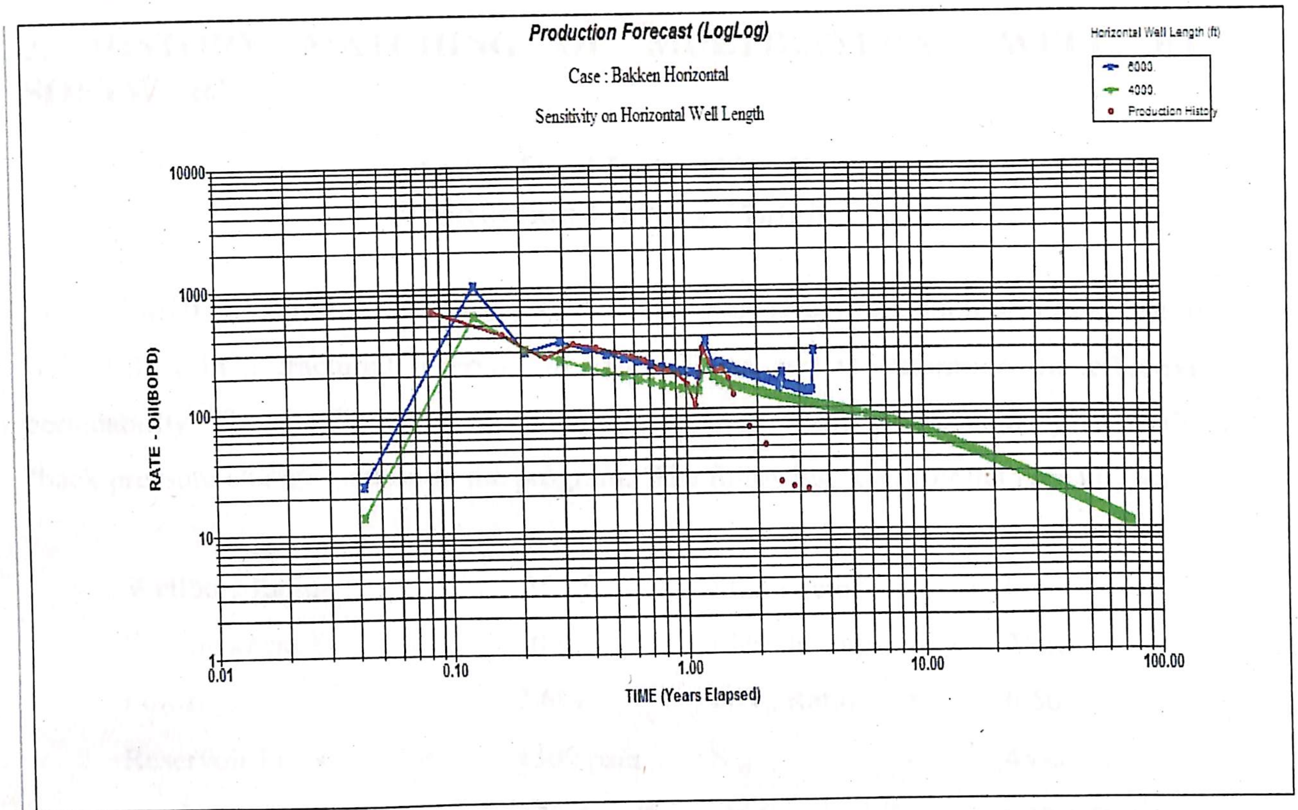




Production Forecast
Case : Bakken Horizontal
Sensitivity on Horizontal Well Length
Horizontal Well Length (ft)
6000
4000.
Production History
Cumulative Production (MBO)
TIME (Years Elapsed)



Production Forecast (SemiLog)
Case : Bakken Horizontal
Sensitivity on Horizontal Well Length
Horizontal Well Length (ft)
6000
4000.
Production History
RATE - Oil(BOPD)
Cumulative Production (MBO)



Production Forecast (LogLog)
Case : Bakken Horizontal
Sensitivity on Horizontal Well Length
Horizontal Well Length (ft)
6000.
4000.
Production History
RATE - Oil(BOPD)
10000
1000
100
10
1
0.01
0.10
1.00
10.00
100.00
TIME (Years Elapsed)

2. HISTORY MATCHING OF MULTILATERAL WELL BY SOFTWARE

Texas Dual Lateral Well
Production History Match

The JTI MULTILATERAL was used to match the historical production of a dual lateral well drilled in a fractured reservoir in south Texas and to determine the effective permeability. The installation of rod pumps in the well was approximated by using the "back pressure change" option in the program. The following reservoir data are known.

Wellbore radius	=	.354 ft.	Skin Factor	=	0.0
Pay thickness=	=	50 ft	Elev. In Pay	=	25 ft
Porosity	=	2.6%	k_v/k_h Ratio	=	0.50
Reservoir Press	=	4300 psia	S_{wi}	=	45%
Res. Temp.	=	275 deg. F	GOR	=	900 scf/stb
Total Compress.	=	.000015 1/psi			
Decline Exp.	=	.3			
Drainhole Length	=	2000 ft.			

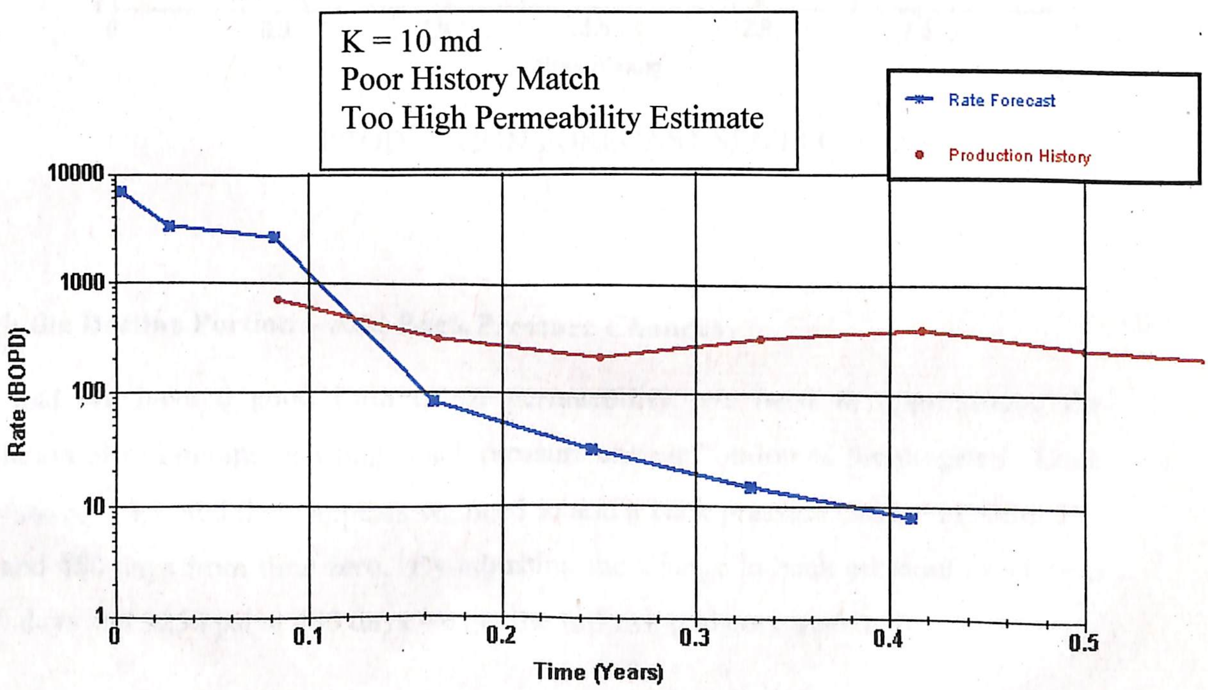
The production history is tabulated below.

Month	STB/d	Cumulative, MSTB
1	706	20
2	311	27
3	223	34
4	328	44
5	395	56
6	265	64
7	203	66
8	112	67
9	475	80
10	491	94
11	176	99
12	319	108
13	255	112

14	131	116
15	108	118
16	528	129
17	192	134
18	126	138
19	111	141
Month	**STB/d**	**Cumulative, MMCF**
20	72	143
21	93	145
22	92	147
23	91	150
24	51	151
25	144	152
26	75	154
27	56	156
28	35	157

Matching Initial Rate- Initial Permeability Guess

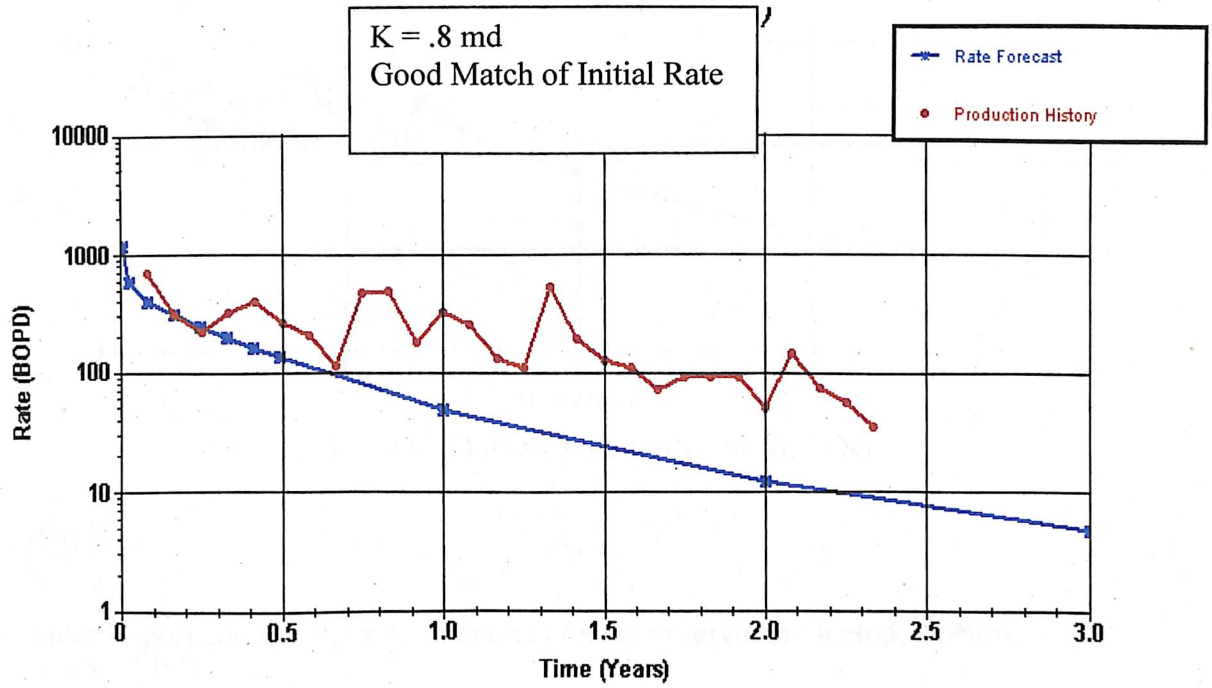
To estimate permeability, a guess of 10 md is made and compared



PRODUCTION FORECAST SEMI LOG

Matching Initial Rate – Fine Tune Permeability

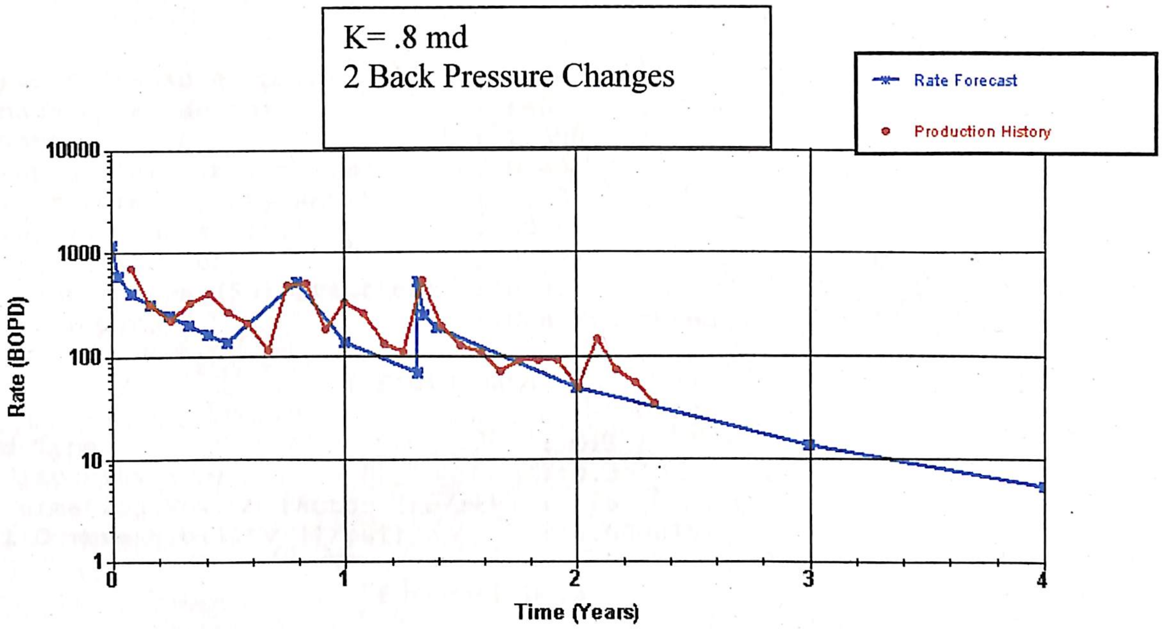
It appears that the 10md estimate was too high. Now try 1md and fine tune to .8md



PRODUCTION FORECAST SEMI LOG

Match the Decline Portion – Add Back Pressure Changes

Now that we have a good estimate of permeability, we need to approximate the installation of rod pumps by using "back pressure change" option of the program. Look at the above graph and there appears we need to add a back pressure change at about 290 days and 480 days from time zero. By adjusting the change in back pressure to 3450psi at 290 days and 3250 psi at 480 days we get the following history match.



PRODUCTION FORECAST SEMI LOG

The Tabular Report and the 4 graphs generated by the program are included below.

MULTILATERAL 1.1

Report Generated By :
Title :
Department :
Company :
Case Name : Texas Well

Well Data

Well Name : Dual lateral
Measured Depth (ft.) : 10000.0
Total Vertical Depth (ft.) : 6000.0

Drainhole data

Number of Drainholes : 2
Coordinate System : Cylindrical

Drain hole#	Elevation (ft.)	Rw (ft.)	Treat as Fractured	Angle (deg.)	Start (ft.)	End (ft.)
1	25.0	0.17	No	0	100	2100
2	25.0	0.17	No	180	100	2100

Reservoir Data

Reservoir Pressure (psia)	:	4300
Drainage Area (acres)	:	640
X/Y Ratio	:	1.500
Horizontal Permeability (md)	:	0.800
Ver./Hor.Permeability Ratio	:	0.50
Net Pay Thickness (ft.)	:	50.0
Porosity (fraction)	:	0.026
Water Saturation (Sw)(fraction)	:	0.45
Reservoir Type	:	Non-Fractured

Fluid Data

Fluid Type	:	Oil
Oil Viscosity (cp)	:	0.3
Oil Formation Volume Factor (rb/stb)	:	1.6
Total Compressibility (1/psi)	:	0.000015

Forecast Data

Production Type	:	Constant Pressure Production
Common Flowing Pressure(Pwf) (psi)	:	3650
Max. Allowable Rate	:	9999999.0
Economic Limit	:	10.0

Decline Data

Decline Type	:	Arp's Fetkovich Curve
Decline Exponent	:	0.3
Decline Coefficient	:	0.008 1/days
No. Of Back Pressure Changes	:	2.0
Time1 (days)	:	290.0
Bottom Hole Pressure1 (psia)	:	3450.0
Time2 (days)	:	480.0
Bottom Hole Pressure2 (psia)	:	3250.0

Time to Pseudosteady state	=	39.6 days
Original Oil in Place	=	2290300 BBLS

Calculation

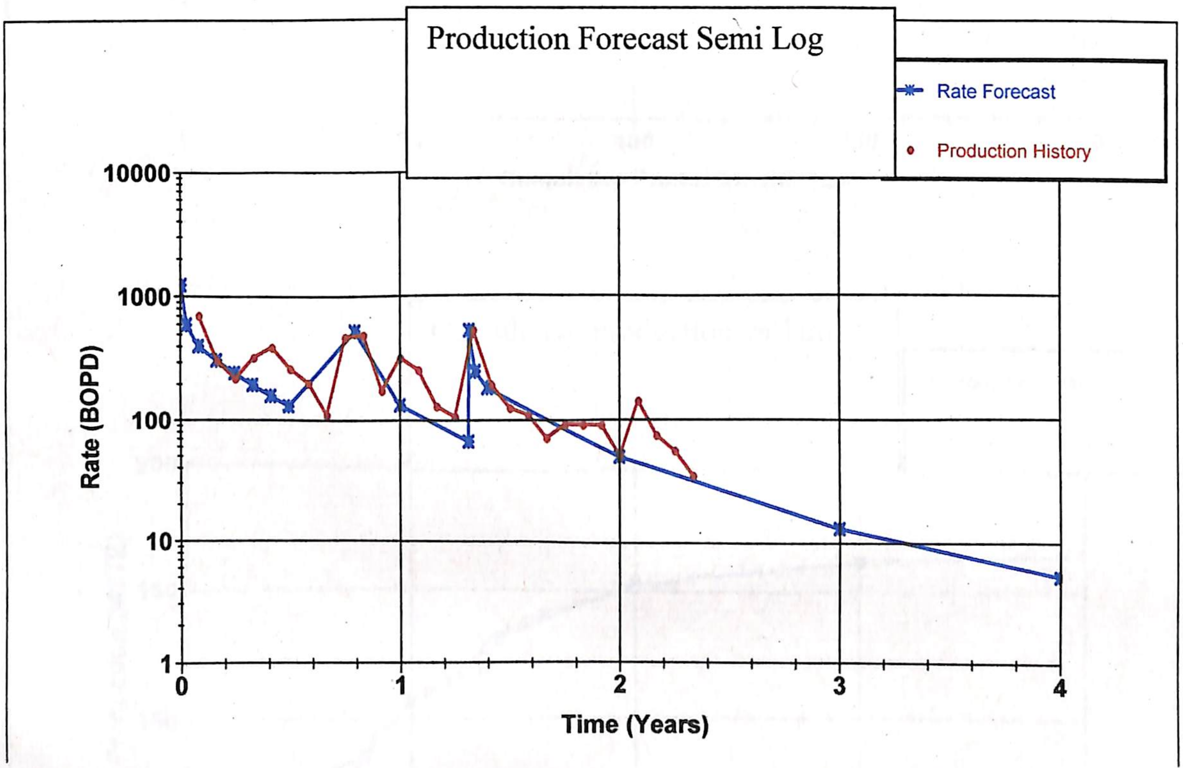
Time (Days)	Time (Years)	Rate (BOPD) or Pressure(psia)	Cumulative (MSTB)	Recovery (%)
1.0	0.0	1209	1	0.1
10.0	0.0	589	15	0.7
30.0	0.1	401	35	1.5
60.0	0.2	310	50	2.2
90.0	0.2	246	58	2.5
120.0	0.3	198	65	2.8
150.0	0.4	161	70	3.1
180.0	0.5	133	75	3.3
290.0	0.8	518	86	3.7

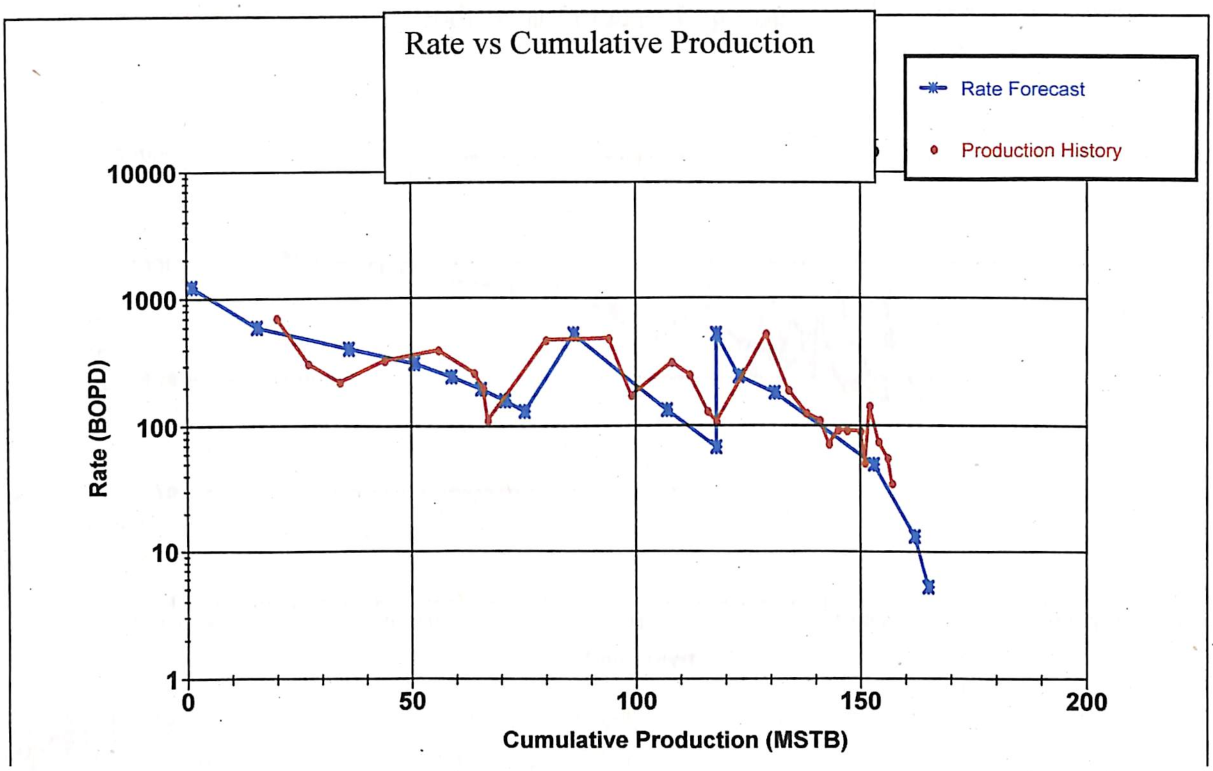
365.0	1.0	134	106	4.6
479.0	1.3	69	117	5.1
480.0	1.3	515	117	5.1
490.0	1.3	246	122	5.4
510.0	1.4	182	130	5.7
730.0	2.0	51	152	6.7
1095.0	3.0	14	162	7.1

Well economic limit reached in 1460.0 days

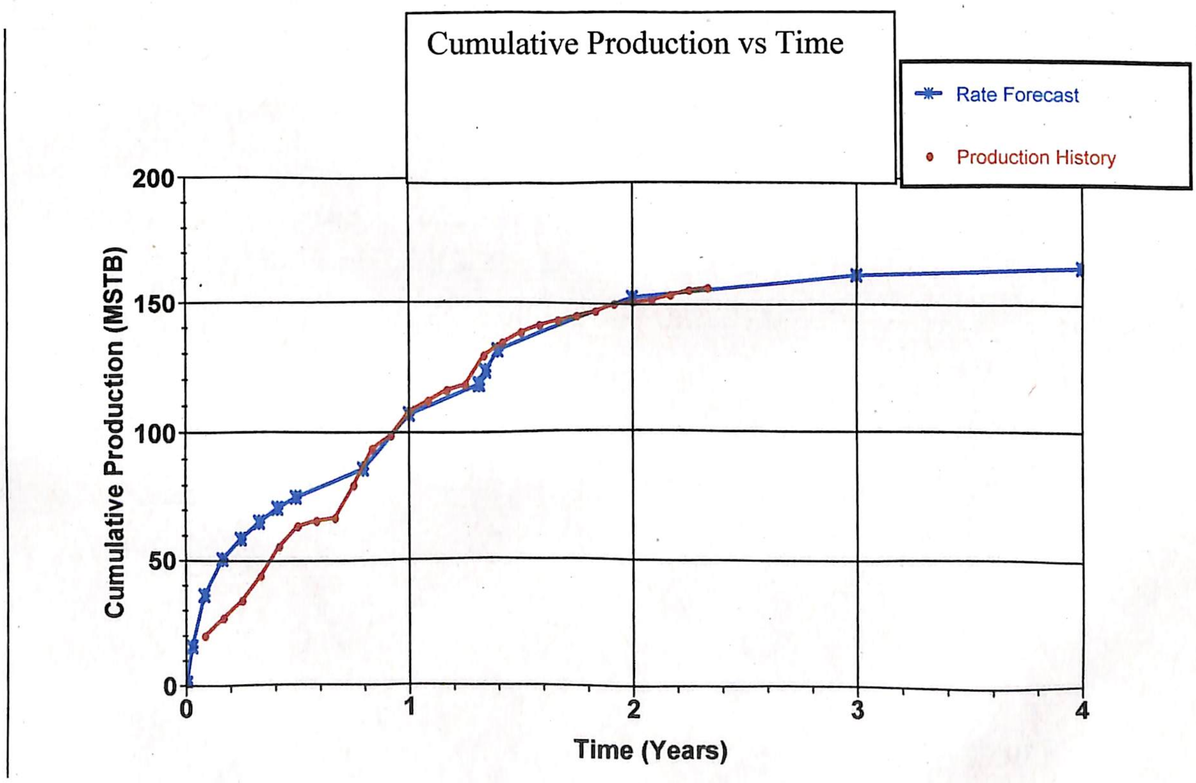
1460.0	4.0	5	165	7.2

Recovery factor is reasonable at 7.2%.

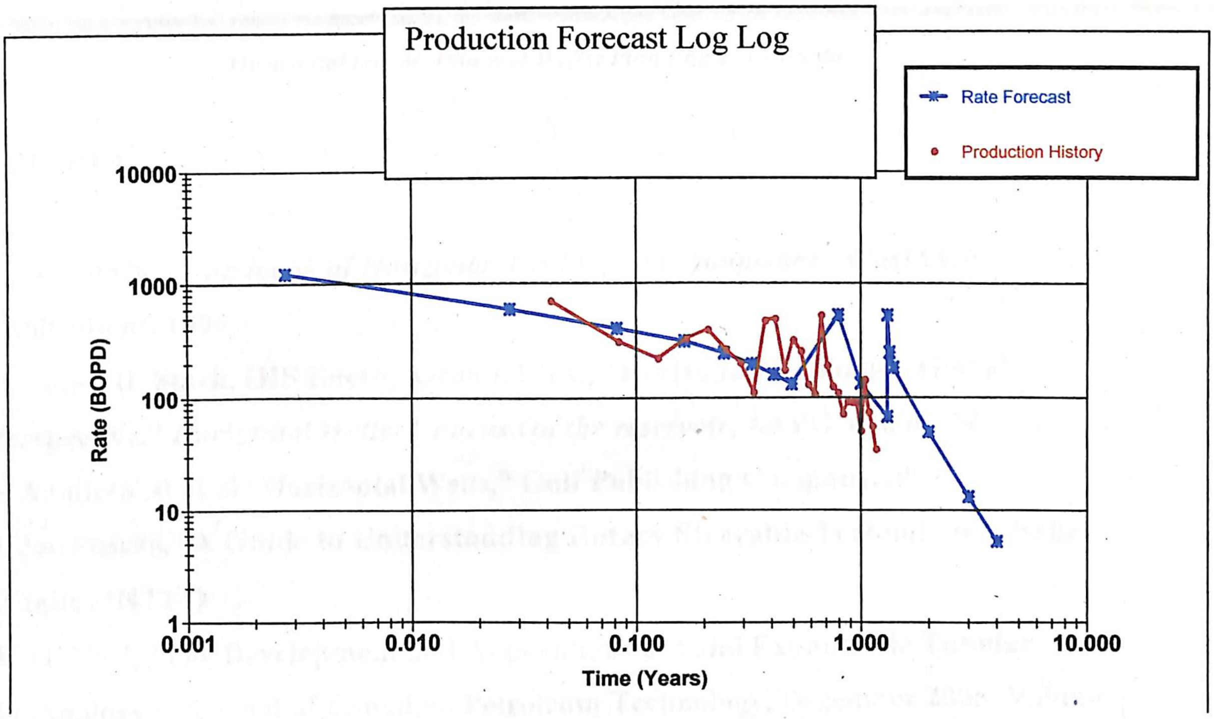




Rate vs Cumulative Production
Rate Forecast
Production History
10000
1000
100
10
1
0
50
100
150
200
Rate (BOPD)
Cumulative Production (MSTB)



Cumulative Production vs Time
Rate Forecast
Production History
200
150
100
50
0
0
1
2
3
4
Cumulative Production (MSTB)
Time (Years)


Production Forecast Log Log
Rate Forecast
Production History
Rate (BOPD)
10000
1000
100
10
1
0.001
0.010
0.100
1.000
10.000
Time (Years)

REFERENCES

1 . *World Oil's Handbook of Horizontal Drilling and Completion,* World Oil Publications, 1995

2 . Philip H. Stark, IHS Energy Group, USA., "Horizontal Drilling-A Global Perspective," *Horizontal Wells-A Focus On the reservoir*, AAPG Vol. no-34

3. Aguilera ,R et al "Horizontal Wells," Gulf Publishing Company,1991

4. Jon Ruszka, "A Guide to Understanding Rotary Steerable Technology", Baker Hughes INTEQ

5. G. Noel, "The Development and Applications of Solid Expandable Tubular Technology", Journal of Canadian Petroleum Technology, December 2005, Volume 44, No.12.

6. Mike Sumrow, Expandable tubular gaining industry confidence, January 21, 2002, Oil & Gas Journal.

7. Rod Rezvani, Halliburton/Sperry Sun, and Bruce Techentien, Halliburton Energy Services Inc., "Torque and Drag Modeling Predicts Tension, Compression, and Torque Limits for Horizontal Openhole Completion Systems,"AADE-05-NTCE-50

8. Blaine C. Comeaux, Sperry-Sun Drilling Services, "Implementation of a Next Generation Rotary Steerable System," AADE 01-NC-HO-25

9. Warren, T.M., "Technology gains momentum," World Oil, September 1997, pp. 101–105

10. Edgar W. Van Sickle, William D. Myers, Simon P. Benavides, Baker Atlas and Kristian Vargervik, Baker Oil Tools, "Horizontal-Oriented Perforating System Optimizes Perforating Efficiency and Production," Baker Inteq pp 34-43,October 2003.

11. George Sutherland , "Development & Application of Versatile and Economical 3D Rotary Steering Technology," AADE 01-NC-HO-21

12. Warren, T.M., "Slimhole Rotary-steerable system Broadens Applications, "World Oil, September 1997, pp. 83–97.

13. Peter Kostel and Knut Ostvang, SPE Statoil"Completion of Horizontal and ERD wells at Stratjford",SPE Paper no.28559,December 1995.

14. L.-B. Ouyang, SPE, and B. Huang, SPE, Chevron Energy Technology Co., "An Evaluation of Well Completion Impacts on the Performance of Horizontal and Multilateral Wells," SPE Paper no. 96530

15. M.D. Erwin, SPE, ConocoPhillips Alaska Inc., and D.O. Ogbe, SPE, U. of Alaska Fairbanks, "Predicting Openhole Horizontal Completion Success on the North Slope of Alaska," SPE paper no. 97121

16. Robert C. Burton and Richard M. Hodge, ConocoPhillips, "Key Drilling and Completion Concerns in Horizontal Wells,"AADE-03-NTCE-16

17. Chris Lenamond, Schlumberger Drilling & Measurements, "A Graphical Hole Monitoring Technique to Improve Drilling in High-Angle and Inclined Deepwater Wells in Real-Time," AADE-03-NTCE-24.

18. S. D. Joshi, SPE, Joshi Technologies International, Inc., "Cost/Benefits of Horizontal Wells," SPE paper no. 83621

19.C Cameron , "Drilling fluids Management For ERD Wells, "SPE paper 72290

20. TAML Multilateral Classification System.

REFERENCES FOR RESERVOIR ASPECTS

1. Van Everdingen A,F "The Skin Effect & Its Influence on the Productive Capacity of a Well", Trans, AIME, vol 198, pp 171, 1953.
2. Gringarten, A.C, Ramey, H.J, jr. & Raghavan, R, "Unsteady State Pressure Distribution Created by a well with a Single infinite Vertical Fracture", SPE, Aug 74.
3. Mutalik P.N, Godbole S.P, & Joshi S.D, "Effect of Drainage Area Shapes on the Productivity of Horizontal wells", SPE paper 18301, 1988.
4. Borisov, Ju. P, "Oil Production Using Horizontal & Multiple Deviation Wells", Nedra, Moscow, 1964.
5. Giger, F.M, Reiss, L.H & Jourdan, A.P, " The Reservoir Engineering Aspect of Horizontal Drilling", paper SPE 13024, 1984.
6. Renard, G.I & Dupuy, J.M, "Influence of Formation Damage on the Flow Efficiency of Horizontal Wells", paper SPE 19414, 1990.

7. Joshi S.D, " A Review of Horizontal Well & Drainhole Technology", paper SPE 16868, 1988.
8. Joshi S.D, "Augmentation of Well Productivity Using Slant & Horizontal Wells", journal SPE, 1988.
9. Economides, M.J & Nolte, K.G, "Reservoir Stimulation".
10. Joshi S.D, "Production Forecasting Methods for Horizontal Wells", SPE paper 17580, 1988.
11. Mukherjee, H. & Economides, M.J, " A Parametric Comparison of Horizontal & Vertical Well Performance', paper SPE 18303, 1988.
12. Babu, D.K & Odeh, A.S, "Productivity of a Horizontal Well", SPE Reservoir Engineering.
13. Joshi, S.D, "Horizontal Well Technology", Pennwell books.
14. "Horizontal Wells", Gulf Publishing Company.
15. Emerson, B, "Optimizing Production Through Expandable, Intelligent Multilateral Wells", Baker Oil Tools.
16. Aziz, K. "Productivity & Injectivity Of Horizontal Wells", report 1999.
17. TAML Multilateral Classification System.