Formation Damage and Horizontal Wells - A Productivity Killer?

D. Brant Bennion, F. Brent Thomas, Ronald F. Bietz, Hycal Energy Research Laboratories Ltd.

Abstract

The use of horizontal drilling is gaining widespread frequency throughout the world. Production results from many horizontal wells have been disappointing, and it is believed that when this has occurred in situations where viable reservoir quality has been present, near wellbore formation damage effects have been a major contributor to the marginal flow performance. Due to the fact that most horizontal wells are completed in an open hole fashion, even relatively shallow invasive near-wellbore damage (that would be penetrated by conventional perforation practices in cased and cemented vertical completions) may substantially impede flow. Drilling induced damage may include fines mobilization, invasion of mud solids, mechanical glazing, phase trapping or chemical reactivity between invading fluids and the formation matrix or in-situ fluids. Calculations illustrate how the permeability of horizontal wells can be reduced dramatically by high near wellbore skins and how this damage effect is attenuated as horizontal to vertical permeability ratio is increased (such as in highly laminated sands). They also illustrate how damage effects are reduced in situations of high vertical permeability, such as formations containing natural vertical fractures which are penetrated by the horizontal well. Underbalanced drilling is discussed as a solution to some horizontal well formation damage problems, and the importance of maintaining a continuous underbalance pressure condition during the entire drilling operation to obtain optimum results is emphasised. A list of reservoir parameters which should be evaluated to design an effective drilling program is presented, and a brief discussion of special core analytical techniques used to optimize drilling fluid and drilling process design is presented.

Introduction

Horizontal wells are being utilized throughout the world in an ever increasing fashion to attempt to increase production rates by maximizing reservoir exposure, targeting multiple zones, reducing drawdowns to minimize premature water or gas coning problems, exploit thin pay zones and, more recently, in such processes as steam-assisted gravity drainage and as injectors and producers in secondary and tertiary enhanced oil recovery processes. Underbalanced drilling using horizontal well technology has also increased as a means of attempting to increase productivity from horizontal wells by reducing formation damage, improve ROP and reduce drilling and stuck pipe problems in severe lost circulation zones.

The use of conventional technology to drill and complete horizontal wells has resulted in disappointing results in many applications, due to what is believed to be formation damage effects. This paper reviews near wellbore skin damage from a mechanistic view in horizontal versus vertical completions, highlights reasons why formation damage effects may be more significant in horizontal versus vertical well applications and reviews current technology levels which are being utilized to attempt to reduce formation damage effects in horizontal well applications.

Mechanism of Formation Damage During Drilling of Horizontal Wells

Mechanisms of formation damage which may be operative in reducing the productivity of horizontal wells have been discussed in the literature by various authors. These damage mechanisms can be grouped into several major categories, these being:

Fines Migration. Fines migration is the motion of naturally pre-existing particulate matter in the pore system. This may be induced during the drilling process by high fluid leakoff rates of water or oil-based mud filtrate into the near wellbore region caused by elevated hydrostatic overbalance pressures or excessively high underbalance pressures.

External Drilling/Mud Solids Invasion. The invasion of artificial mud solids (weighting agents, fluid loss agents or bridging agents), or naturally generated mud solids produced by bit-rock interactions and not removed by surface solids control equipment into the formation during overbalanced drilling conditions.
Phase Trapping. The loss of both water or oil based drilling mud filtrate to the formation in the near wellbore region due to leakoff during overbalanced drilling operations, or due to spontaneous imbibition in some situations during underbalanced drilling operations, can result in permanent entrapment of a portion or all of the invading fluid resulting in adverse relative permeability effects which can reduce oil or gas permeability in the near wellbore region.

Chemical Incompatibility of Invading Fluids with the In-situ Rock Matrix. Many formations contain potentially reactive material in-situ in the matrix, including reactive swelling clays such as smectite or mixed layer clays, or deflocullatable materials such as kaolinite or other loosely attached fines. Expansion or motion of these materials within the pore system, which may be induced by the invasion of non-equilibrium water based mud filtrates into the near wellbore region, can cause considerable reductions in permeability.

Fluid-Fluid Incompatibility Effects Between Invading Fluids and In-Situ Fluids. Oil or water based mud filtrates invading into the near wellbore region during overbalanced drilling processes can react adversely with in-situ hydrocarbons or waters present in the matrix with detrimental results which may reduce permeability. Problems would include the formation of insoluble precipitates or scales between incompatible waters, de-asphalting of the in-situ crude or hydrocarbon based drilling fluid caused by blending of incompatible oils, or the formation of highly viscous stable water in oil emulsions due to turbulent blending of invaded filtrates with either in-situ water or oil.

Near Wellbore Wettability Alteration and Surface Adsorption Effects. Many drilling fluid additives used for mud rheology, stability, emulsion control, corrosion inhibition, torque reduction or lubricity contain polar surfactants or compounds which can be preferentially adsorbed on the surface of the rock. The physical adsorption of these compounds can cause reductions in permeability by the physical occlusion of the pore system, in the case of high molecular weight long chain polymers, particularly in low permeability porous media where the small pore throats may be easily bridged by long chain polymer molecules. Polar compound adsorption may alter the wetting characteristics of the matrix in the near wellbore region, generally in most cases to a preferentially more oil-wet state. This causes a potentially significant increase in water phase relative permeability in this region, which may adversely elevate producing water oil ratio for the well if the completion is in a zone where a mobile water saturation is present.

Mechanical Near Wellbore Damage Effects. Mechanical action of the bit, combined with fine cuttings, poor hole cleaning and a poorly centralized drill string may result in the formation of a thin "glaze" of low permeability surrounding the wellbore. This problem is believed to be aggravated by straight gas drilling operations, where a large amount of heat is generated at the rock-bit interface due to the poor heat transfer capacity of the gas based drilling fluid system in comparison to a conventional drilling fluid. Open hole completions in low permeability clastic formations tend to be the most probable candidates for this type of damage. Glazing will not generally occlude large permeability features, such as fractures or vugs, and the glaze is usually readily removable in carbonate based formations with a light acid wash due to its highly soluble nature.

Factors Which Will Tend to Increase the Severity of Near Wellbore Damage

The overriding factor which will increase the severity of near wellbore damage will be the extent of incursion of fluids and solids into the reservoir and how these materials will react with the formation once they come into contact with the rock matrix.

Factors which will tend to increase the fluid/solid loss performance of a drilling mud in a horizontal drilling application may include:

Overbalance Pressure. The greater the density of the hydrostatic fluid column and resulting downhole pressure generated in comparison to the net effective reservoir pore pressure, the greater the tendency for losses of both fluids and mud solids to the formation. Highly weighted mud systems (due to either deliberate high concentrations of weighting agents for well control or poor surface solids control resulting in an undesirable build-up of a high concentration of dense natural silicate or carbonate based formation drill solids in the fluid system), high backpressures or drilling operations in significantly pressure depleted formations (particularly in deep zones) may all contribute to high overbalance pressures. Overbalance pressures in excess of about 7000 kPa (1000 psi) are generally considered to be severe and may cause serious losses to the formation, particularly in zones of high reservoir quality.

High Solids Content. A high concentration of artificial or natural solids in the mud system, which are inappropriately sized to form a low permeability filter cake, can either invade into the rock matrix (if the solids are too small, that is, less than approximately 30% of the median pore throat aperture), or may screen off on the formation face forming porous, high permeability, thick filter cakes which may result in long-term filtrate seepage and stuck pipe problems if the solids are too large. For an open hole completion scenario, an appropriate size distribution of particulate matter in the mud is essential to establish a sealing, low permeability filter cake rapidly on the face of the formation. This will minimize solids invasion to directly at the wellbore-formation interface where it can hopefully be readily removed either by direct mechanical backflow or some type of very localized chemical or mechanical stimulation treatment.

Poor Fluid Rheology. The use of high API fluid loss, low viscosity fluids will generally increase the potential for filtrate losses to the formation. Consideration is often given to the use of so called "clear" fluids with no added solids in the hopes that if the base fluid is compatible with the formation no damage will occur, even if significant fluid losses occur during the drilling process. Unfortunately, the presence of naturally generated drill
solids in clear fluid systems often results in near wellbore mechanical damage as large volumes of the base fluid, along with the often inappropriately sized naturally generated fines from the drilling process, are carried off into the formation. The use of appropriate viscosifiers/polymer can assist in the reduction of uncontrolled fluid losses to the formation in some cases, and should be evaluated for each specific situation under consideration.

**Poor Base Fluid Compatibility.** Even in the best designed overbalanced drilling operation, and often in many so called "underbalanced" drilling operations, some unavoidable losses of mud filtrate to the formation occur. Shallow invasion may not be significant for cased/perforated completions, but may be quite problematic for open hole situations. This being the case, it is usually prudent to design the base mud filtrate with full compatibility with the formation matrix in mind. This would include anticipating problems with reactive clays, in-situ fluids (emulsion potential and precipitation ability) and phase trapping (possibility of including IFT reducing agents such as surfactants or alcohols to lessen the impact of phase trapping if fluid losses do occur).

**Presence of Zones of Extreme Permeability.** Fluid losses and potential damage will generally be more significant in zones of high permeability, such as high perm intercrystalline streaks, fractures or interconnected vugular porosity which may be penetrated by the horizontal well. Conversely, if invasion depth is not too significant, these zones may be the most forgiving and easy to clean up in some respects due to more favourable capillary pressure relations and larger pore sizes.

**Why Is Damage More of a Concern In Horizontal Versus Vertical Wells?**

There are a number of reasons why horizontal wells appear to be more susceptible to formation damage than their vertical well counterparts. One of the major reasons is related to the completion practices used for most horizontal wells. The fact is that the majority of horizontal wells are completed either a direct open hole fashion, or with some type of slotted or prepacked liner, which, as far as produced fluids are concerned, is equivalent to an open hole completion. This is in comparison to vertical wells where most of the wells are cased, cemented and perforated. One can thus see that a degree of relatively small invasive formation damage, several centimetres in depth about a vertical wellbore may be insignificant, as a normal perforation charge will penetrate beyond the damaged zone and access undamaged reservoir matrix to facilitate reasonable production rates if a permeable formation is present. Many types of damage, such as solids invasion, do, in fact, tend to be very localized about the wellbore in this limited type of radius, particularly in the absence of zones of extreme permeability (such has highly fractured or vugular porosity systems).

It can be observed in an open hole horizontal completion, however, that the produced reservoir fluids must pass completely through the zone of damage which may have been created about the wellbore during the drilling process. Although shallow in some cases, the permeability of this affected zone may be extremely low, creating a very high zone of what is referred to as "skin" damage about the wellbore. Thus, even relatively shallow invasive damage, which may be insignificant in a cased and perforated completion, can be very substantial in an open hole scenario. Other reasons contributing to increased severity of damage in horizontal versus vertical wells could include:

**Greater Depth of Invasion.** Drilling times for horizontal wells are usually greater than conventional vertical wells. Fluid exposure time at the heel of the well may be significant if poor mud rheology is present in an overbalanced condition, or if the mud filter cake is continuously disturbed by a poorly centralized drill string or multiple tripping operations, invasion depth of damaging mud filtrate and solids into the near wellbore region may be substantially greater than in a conventional vertical well application.

**Selective Cleanup/Damage.** The large exposed length of a horizontal well often results in zones of highly variable reservoir quality being penetrated. High permeability streaks may preferentially clean up upon drawdown resulting in minimal drawdown pressure being applied to more heavily damaged and invaded portions of the well, making it difficult to obtain an effective cleanup. Production logs on horizontal wells often indicate the majority of the produced fluid is being sourced from only a very small section of the total length of the well.

**Difficulty of Stimulation.** Damaged vertical wells may often be effectively stimulated economically using a variety of penetrative techniques such as hydraulic or acid fracturing, acid or other types of chemical squeezes, heat treatments, etc. These types of processes are not readily economically applied to horizontal wells due to cost and technical considerations associated with attempting to stimulate a section hundreds of meters in length (instead of only a few meters in length as often is the case in a vertical well). Therefore, most horizontal well stimulation treatments tend to be relatively non-invasive in nature, such as acid washes, and may only be effective in penetrating shallow near wellbore damage.

**Anisotropic Flow.** The flow patterns into a horizontal well are completely different than a vertical well, this is schematically illustrated as Figure 1. It can be seen that a vertical well in a uniform strata of cross bedded planes which it penetrates in an orthogonal fashion will drain the reservoir in a uniform planar radial fashion. Conversely, a horizontal well sources fluids from both the vertical and horizontal planar direction and hence is much more radically affected by variations in the vertical permeability of the reservoir. This shall be described in greater detail in the following sections of the paper.

In a similar fashion, invasion occurring during an overbalanced drilling operation is governed by directional permeability which exists in the reservoir. This is illustrated for a vertical and horizontal well as Figure 2. It can be seen that invasive damage about a vertical well in a situation of uniform non directional
horizontal permeability will be in a cylindrical pattern, with the depth of invasion in an unimpeded fluid loss situation being governed by the variable permeability of the strata under consideration. In a horizontal well, due to the frequent anisotropy of horizontal versus vertical permeability in many reservoir systems, the invasion pattern will be elliptical in nature, with the direction of the primary axis of the invasion ellipsoid being oriented in the direction of highest permeability.

Flow Into Horizontal and Vertical Wellbores

Uniform flow into a vertical well of constant and non directional horizontal permeability can be described by the Equation:\(^10\):

\[ Q = \frac{2\pi kh (P_e - P_w)}{\mu \ln \left( \frac{R_e}{R_w} \right)} \]  

(1)

where

- \( Q \) = low rate of reservoir fluid (m\(^3\)/s)
- \( k \) = Average horizontal permeability (m\(^2\))
- \( h \) = Pay zone height (m)
- \( P_e \) = Reservoir pressure at effective drainage radius (Pa)
- \( P_w \) = Wellbore pressure (Pa)
- \( \mu \) = Viscosity (Pa*s)
- \( R_e \) = Effective drainage radius (m)
- \( R_w \) = Wellbore radius (m)

The effect of near wellbore damage can be included in Equation 1 through the use of a resistance factor commonly called the "skin" factor. This concept was introduced in 1953 by van Everdingen:\(^1\):

\[ \Delta P_{skin} = S \left[ \frac{Q_0}{2\pi kh} \right] \]  

(2)

Thus, for a constant flow to the wellbore, the skin, induced by a combination of the invasive damage mechanisms which have been discussed previously, adds a constant pressure drop to the total drawdown (or, in other terms, a portion of the available drawdown is dissipated in overcoming the fluid resistance to flow through the zone of impaired permeability created about the wellbore). A wellbore with normal radius of \( R_w \) therefore, with a skin effect present, behaves as if the well were a "clean" well with a reduced wellbore radius given by:

\[ R_{w,eff} = R_w e^{-s} \]  

(3)

where \( R_{w,eff} \) is the reduced wellbore radius which is substituted into Equation 1.

For a horizontal well of uniform drainage and permeability, the flow equation is given by:\(^10\):

\[ Q = (P_c - P_w) \frac{2kLh}{\mu} \left[ \frac{1}{1 + \frac{h}{\pi \ln \left( \frac{h}{2\pi R_w} \right)}} \right] \]  

(4)

where

- \( L \) = Length of horizontal section (m)
- \( x \) = Distance to horizontal no flow boundary (m)

To incorporate the effect of skin damage in a horizontal well, the skin factor, as described in Equation 3, can be substituted for the well radius as given in Equation 4. To account for the common situation of asymmetric horizontal and vertical permeabilities, which exist in many formations, the terms \( h \) and \( R_w \) in Equation 4 can be further modified as follows:

\[ h^* = \sqrt{\frac{k_h}{k_v}} \]  

(5)

\[ R_{w}^* = 0.5 \left( R_w \left( 1 + \sqrt{\frac{k_h}{k_v}} \right) \right) \]  

(6)

where

- \( k_h \) = Horizontal permeability (m\(^2\))
- \( k_v \) = Vertical permeability (m\(^2\))

The resulting final formulation for inflow production rate to a horizontal well with disparate horizontal versus vertical permeability can be expressed as follows:

\[ Q = (P_c - P_w) \frac{2k_hLh}{\mu} \left[ \frac{1}{1 + \frac{h^*}{\pi \ln \left( \frac{h^*}{2\pi R_{w}^*} \right)}} \right] \]  

(7)

Table 1 provides a list of the test parameters which were used for the comparative calculations. All results from the calculations are represented on the basis of "normalized flow". The normalized flow represents the actual flow rate for the given horizontal or vertical well situation at the effective "skin" condition, divided by the flow rate at the same conditions in an undamaged zero skin condition. Therefore, all curves at zero skin have an effective value of one. The purpose of this form of analysis is not to illustrate the increase in absolute production rate observed when moving from a vertical to a horizontal well application, as this is a rather strong function of effective formation permeability, pay and well geometry, but to illustrate, on a comparative basis, the effect of skin and the productivity of the wells as damage increases. This allows comprehension of the effect and magnitude of permeability reductions to be expected in the case of a severe near wellbore formation damage problem in an open hole horizontal well.
Comparison of Skin Damage in Horizontal Versus Vertical Wells in an Isotropic Permeability Condition

Table 2 provides the results of the calculations on horizontal and vertical well geometries using identical reservoir parameters (as detailed in Table 1). This data is based on isotropic (equal) horizontal and directional permeabilities. Figure 3 illustrates the horizontal and vertical well normalized productivity in a low skin factor (5 = 0-10) regime, and Figure 4 at the range of skin factors up to 500. The data illustrates that preferentially the horizontal well, due to greater length and reservoir exposure (in this geometry) suffers less relative productivity reduction than the equivalent vertical well. However, it should be noted at extreme skin factors (which may occur in a badly damaged overbalanced open hole completion) that the horizontal well productivity is reduced to only 13.9% of the original value (in comparison to the vertical well whose productivity is reduced to 1.49% of the initial value).

Comparison of Horizontal to Vertical Well Performance in Zones of Isotropic Permeability But Variable Pay

Table 3 summarizes the results of the calculations conducted using vertical and horizontal well geometries for pay zones thicknesses of 2, 10 and 50 meters respectively in an isotropic permeability situation. The data has been plotted for low skin factors as Figure 5 and for high skin and damage values as Figure 6. Since the data is presented on a normalized basis the profiles for the vertical well are identical for all three pay situations (as the flow rate increase is a simple linear multiple of pay zone thickness in this situation). It can be seen that on a normalized basis horizontal well open hole performance becomes more sensitive to near wellbore formation damage effects as net pay increases (even though on an non-normalized basis total flow rate will likely increase). This can be explained by the greater contribution to flow from the over/underlying sections of the formation in a thick pay zone. Boundary effects caused by damage in such a situation result in preferential reductions in the ability of the well to effectively access the entire drainage volume and energy of the overlying formation zones.

Comparison of Horizontal to Vertical Well Performance in Reservoir Zones of Anisotropic Permeability

Table 4 summarizes the results of these calculations and the data have been plotted for low skin factors as Figure 7 and high skins as Figure 8. These situations mimic the more common real life reservoir case where vertical and horizontal permeability are not equal. Low vertical permeabilities, creating adverse permeability ratios, are common in many sands, particularly if a high degree of interlamination is present in the system. Calculations have been conducted for vertical to horizontal permeability ratios of 0.1, 0.01 and 0.001 respectively. Absolute productivity of horizontal wells, in general, is significantly reduced with adverse $k_v/k_h$ ratios and in many cases horizontal wells may not be capable of economic production rates at extreme $k_v/k_h$ ratios, even in the total absence of any near wellbore formation damage effects. Examination of the data indicates that the severity of formation damage is radically increased as formation $k_v/k_h$ ratio becomes more and more adverse. A large number of horizontal wells are drilled in formations exhibiting $k_v/k_h$ ratios of less than 0.1, so the impact of even a relatively small amount of near wellbore skin on ultimate well productivity is apparent. It is interesting to note at very adverse $k_v/k_h$ ratios the horizontal well productivity ratio is actually affected more significantly than the vertical well value, a possible explanation as to why some very badly damaged horizontal wells actually perform more poorly than offsetting vertical well counterparts.

Table 4 and Figures 7 and 8 also illustrate the effect of the opposite situation, high vertical permeability in comparison to horizontal permeability. This situation might occur in a reservoir where the horizontal well is orthogonally intersecting vertical fracture planes as commonly occurs with horizontal well applications in areas such as the Austin Chalk in Texas. In this case, the reverse situation holds true that, the higher the $k_v/k_h$ ratio becomes, the less sensitive to skin damage the production rate. At a $k_v/k_h$ of 1000, which would not be uncommon for a tight matrix highly fractured formation, it can be seen that the production rate is virtually insensitive to skin, even at very high skin values. This is somewhat of an oversimplification, as we are assuming in these calculations that the entire wellbore is contributing to flow, rather than a few isolated fractures. Therefore, massive fluid losses to a vertical fracture system may still result in productivity reductions. Well results in areas such as the Austin Chalk, where highly damaging drilling practices such as mud cap drilling are routinely utilized and highly productive horizontal wells are still obtained, suggest, however, that the general trend predicted here is correct for vertically fractured formations.

Underbalanced Drilling

The previous analysis has illustrated that near wellbore skin damage in a horizontal well can significantly reduce productivity to the point where, in some situations, the wells are uneconomic. Much of this damage is associated with invasion of fluids and solids during the conventional overbalanced drilling process. Underbalanced drilling has been used in recent years as a means to attempt to reduce invasive formation damage and improve the productivity of wells in high damage/high fluid loss prone scenarios. Success with underbalanced drilling operations has been mixed, primarily due to misapplication of the technology in many situations and a failure to maintain a continuously underbalanced condition at all times during the drilling operation. Since no protective filter cake is formed during a properly executed underbalanced operation, due to a net outflow of fluids from the formation, even relatively short periods of periodic overbalance pressure can result in significant invasion of fluids and solids into the formation and severe damage, sometimes of greater magnitude than would have occurred if a well designed and conceived overbalanced system with good fluid loss control had been used in the same situation. In certain conditions damage may occur due to countercurrent imbibition, gravity drainage, mechanical glazing or drawdown effects, even if a continuously underbalanced condition is maintained during the
drilling operation. A detailed discussion of problems associated with many underbalanced drilling operations and suggested screening criteria for the proper design of an underbalanced drilling program is contained in the literature.\textsuperscript{4,12,13}

Fluid Design Criteria to Optimize a Drilling Program to Minimize Near Wellbore Damage in Horizontal Completions

Technology that has proven viable and reliable for successful vertical well applications in a given field often does not provide similar results for horizontal wells. This frequently results in the need to re-design the drilling program from a grass roots basis to obtain a successful horizontal well. The use of the maximum technology that has proven viable and reliable for successful drilling program is contained in the literature.\textsuperscript{4,12,13}

Vertical well applications in a given field often does not provide similar results for horizontal wells. This frequently results in the need to re-design the drilling program from a grass roots basis to obtain a successful horizontal well. The use of the maximum amount of reservoir data, special core analysis techniques to screen and evaluate various fluid systems and practices, and an experienced design team are all integral components in obtaining the greatest chance of success for a horizontal well application.

A good understanding of the following reservoir parameters is required:

- Current pressure
- Variations in lithology
- Permeability and porosity distribution in the target zone
- Presence of macroporous features such as fractures or vugs
- Composition of the matrix and presence of potentially reactive clays (such as swelling smectitic clays), or mobile or deflocculatable clays (such as kaolinite)
- Initial fluid saturations, wettability of the matrix and relative permeability characteristics to obtain an indication of potential severity of problems with phase trapping and retention
- Pore throat size distribution and fracture aperture size (if present) to quantify size distribution of particulates required to create a stable non-invasive filter cake on the face of the formation to reduce damage effects
- Chemical compatibility between mud filtrate and in-situ formation fluids (emulsion, scale and precipitation potential)

Special core analysis tests are often conducted on representative samples of reservoir core to verify the performance of a given fluid system once preliminary design has been conducted, or to compare the performance of several potential fluid systems to select the least damaging alternative for use in the field. Figure 9 provides a schematic illustration of the region attempted to be simulated in the near wellbore regime using a special core analysis test. Figure 10 provides a detailed schematic of the coreflow head, which is modified such that whole field drilling mud containing a high concentration of solids can be circulated past the face of the sample to mimic dynamic annular flow and a filter cake is allowed to form while fluid losses and cake stability are monitored during a typical dynamic circulation test. Figure 11 illustrates a typical test apparatus and Figures 12 and 13 detail typical fluid loss profiles for various fluid systems as well as a variable drawdown rate return permeability test profile. These variable pressure return permeability tests are conducted to quantify the degree of drawdown required to lift the filter cake from the face of the formation, re-initiate flow and track formation cleanup as a function of drawdown pressure up to the maximum expected drawdown pressure level which can be realistically applied in the field to obtain a realistic evaluation of true fluid performance.

For heterogenous pore systems, variations of the technology can be applied using naturally or synthetically fractured and shimmmed cores (Figure 14) or new full diameter radial coreflood formation damage technology which precisely mimics the radial leakoff pattern seen in the reservoir (Figure 15).

Figure 16 illustrates a modified coreflood apparatus to evaluate underbalanced drilling. These experiments are defined in additional detail in the literature.\textsuperscript{4} The objective of these tests is to determine if problems such as spontaneous imbibition may be apparent during a true underbalanced drilling operation, and also the degree of damage and invasion to be expected if the underbalance pressure condition is lost and low viscosity fluid and solids abruptly invade into the formation. In this fashion, the amount of damage can be compared to a conventional overbalanced fluid system in the same situation, and a risk analysis conducted to ascertain if the extra expense and potential problems associated with an underbalanced drilling operation are justified.

Conclusions

Formation damage in horizontal wells can be a significant impediment to economic production of oil or gas. Near wellbore formation damage mechanisms, which can occur during the drilling process, centre about fluid and solids losses to the matrix and fracture/vug system adjacent to the wellbore during overbalanced operations as well as possible mechanical damage in some situations. Shallow damage is more significant in open hole horizontal wells due to the need to be able to produce through the zone of impaired permeability during ultimate production, in comparison to a cased completion where shallow invasive damage is normally penetrated by a typical perforation charge. Flow calculations indicate that the severity of damage in horizontal wells is significantly increased as the ratio of vertical to horizontal permeability degrades and also to a lesser extent as formation thickness increases. Underbalanced drilling may be a partial solution to many invasive formation damage problems in open hole horizontal wells, but only if properly executed and if a continuous underbalance pressure condition is maintained.

A list of reservoir parameters to evaluate prior to designing a drilling program for an open hole horizontal well has been presented and various special core analysis tests described which are used as a tool to evaluate drilling fluids and program design prior to the cost and risk of actual implementation in the field to obtain optimum performance have been presented.
Acknowledgements

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References


**TABLE 1: List of Simulation Parameters for Vertical and Horizontal Flow Calculations**

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<thead>
<tr>
<th>Parameter</th>
<th>Value (SI)</th>
<th>Value (Field)</th>
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<tbody>
<tr>
<td>Pay Height (h)</td>
<td>8 metres</td>
<td>26.2 ft</td>
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<tr>
<td>Horizontal Permeability (k_h)</td>
<td>5 x 10^{-11} m^2</td>
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<td>Reservoir Pressure (P_r)</td>
<td>20 x 10^6 Pa</td>
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<tr>
<td>Wellbore Pressure (P_w)</td>
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<td>Viscosity (\mu)</td>
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<td>Boundary (x)</td>
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<td>Length (l)</td>
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<td>Well Radius (R_w)</td>
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<tr>
<td>Drainage Radius (R_d)</td>
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<td>Vertical Permeability (k_v)</td>
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**TABLE 2: Normalized Production Rate vs Skin Vertical and Horizontal Wells - Vertical and Horizontal Permeabilities Equal**

<table>
<thead>
<tr>
<th>Skin Factor</th>
<th>Q-Norm (Vertical Well)</th>
<th>Q-Norm (Horizontal Well)</th>
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<td>0</td>
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<td>1.000</td>
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<td>500</td>
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**TABLE 3: Normalized Production Rate vs Skin Vertical and Horizontal Wells, K_v=K_h**

<table>
<thead>
<tr>
<th>Effect of Pay Thickness</th>
<th>Skin Factor</th>
<th>Q-Norm Vertical Well h = 2 m</th>
<th>Q-Norm Horizontal Well h = 2 m</th>
<th>Q-norm Vertical Well h = 10 m</th>
<th>Q-norm Horizontal Well h = 10 m</th>
<th>Q-norm Vertical Well h = 50 m</th>
<th>Q-norm Horizontal Well h = 50 m</th>
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<td>h = 2 m</td>
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**TABLE 4: Normalized Production Rate Vs Skin Vertical and Horizontal Wells Variable k_v/k_h**

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<th>Horizontal Well k_v/k_h = 0.01</th>
<th>Horizontal Well k_v/k_h = 0.001</th>
<th>Horizontal Well k_v/k_h = 10</th>
<th>Horizontal Well k_v/k_h = 1000</th>
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FIGURE 1
FLOW PATTERN PROFILES IN HORIZONTAL vs VERTICAL WELLS

Drainage streamlines in a vertical well

Drainage streamlines in a horizontal well

FIGURE 2
INVASION PROFILE IN HORIZONTAL vs VERTICAL WELLS

Invasion profile in vertical well ($k_v = k_h$)

Invasion profile in a horizontal well ($k_v \neq k_h$)

FIGURE 3
COMPARATIVE NORMALIZED PRODUCTION RATES
HORIZONTAL & VERTICAL WELL, $k_v = k_h$

Normalized Production Rate vs Skin Factor ($S$)

FIGURE 4
COMPARATIVE NORMALIZED PRODUCTION RATES
HORIZONTAL & VERTICAL WELL, $k_v \neq k_h$

Normalized Production Rate vs Skin Factor ($S$)
FIGURE 9
SCHEMATIC OF NEAR HORIZONTAL WELL REGION MINIATED BY SCALING CORE ANALYSIS TEST

Initial Hydrocarbon Flow Direction

Regain Hydrocarbon Flow Direction

Current Exposure Time (hrs)
1. High fluid loss non-bridging “near” fluid system.
2. Pump shuts off under high fluid loss system.
3. Low fluid loss sealing system.