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THE CAUSES, EFFECTS AND MINIMIZATION OF FORMATION DAMAGE IN HORIZONTAL WELLS

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Abstract

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 draw-downs to minimize premature water or gas coning problems and exploit thin pay zones, horizontal drilling is gaining widespread frequency throughout the world. However in many cases where viable reservoir quality has been present, production results from many horizontal wells have been disappointing, and it is believed that, near wellbore formation damage effects have been a major contributor to this disappointing marginal flow performance.

This research work examines the various causes of formation damage in horizontal wells , how the damage affects the well productivity in well configurations whether long or short, with regard to changing reservoir thickness and also with changing horizontal to vertical permeability ratios. It aims to determine the best horizontal well to drill in order to attain maximum production rate in these reservoir conditions. In this project, a developed model was used to aid the prediction of the production rate and the productivity index of the horizontal wells drilled in the afore mentioned reservoir parameters. An industry based software 'PROSPER' was also used to simulate the production rate and ultimately used to confirm the analysis and conclusion gotten using the developed model.

Keywords: formation damage; horizontal well; workover; payzone drawdown; reservoir; hydraulic fracturing; diffferential sticking; permeability; simulation.

1. Introduction

Formation damage can be defined as the reduction of the original or natural permeability of the reservoir rock near the well bore. It can also be defined as any type of a process which leads to a reduction of the productivity of an oil, water or gas bearing formation. Formation damage is an undesirable operational and economic problem that can occur during the various phases of oil and gas recovery from subsurface reservoirs including production, drilling, hydraulic fracturing, and work over operations. It has long been recognized as a source of serious productivity reductions in many oil and gas reservoirs and as a cause of water injectivity problems in many water flood projects.

Formation damage causes substantial reductions in oil and gas productivity in many reservoirs. Damage can be caused by mechanical effects, chemical effects, and the action of bacteria or extreme temperatures associated with thermal recovery processes.

Stimulation procedures required to remove formation damage in horizontal wells are costly and are often unsuccessful or marginally successful.

Formation damage assessment, control, and remediation are among the most important issues to be resolved for efficient exploitation of hydrocarbon reservoirs. Formation damage indicators include;

- Permeability impairment,
- Skin damage, and
- Decrease in well performance.

Formation damage can occur at any time during a well's history from the initial drilling and completion of a wellbore through depletion of a reservoir by production. Operations such as drilling, completion, workovers and stimulations, which expose the formation to a foreign fluid, may result in formation damage due to adverse wellbore fluid/formation fluid or wellbore fluid/formation reactions.

1.1 Skin factor concept

Van Everdingen and Hurst introduced the concept of skin factor to the petroleum industry; they noticed that for a given flow rate, the measured bottom hole pressure was less than that calculated theoretically. This indicated that there was an additional pressure drop to a small zone of changed or reduced permeability around the wellbore and called this "invaded zone", or damaged zone, a skin zone. They suspected that invaded zone is due to reservoir contamination by mud and plugging of some pore spaces around the wellbore. In general, the skin factor in wells can vary from +1 to +10, and even higher values are possible.

Mathematically skin pressure drop is presented by, $s = \frac{kh(\Delta p)_{skin}}{141.2 q \mu_o \beta_o}$

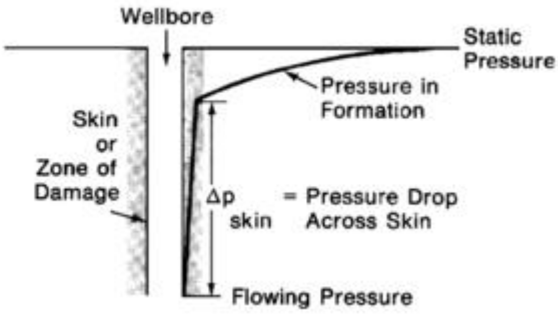

Figure 1 Pressure profile in the near-wellbore region for an ideal well and a well with formation damage

The concept of thin skin in the above equation works well in damaged wells but because of mathematical and physical difficulties when the well is stimulated i.e. negative skin, it has to be generalized.

Hawkins modified the above equation by introducing the concept of thick skin. He defined the skin factor for damaged zone of radius r_s with permeability k_s in a formation with permeability, k, and wellbore radius, r_w $s = \left[\left(\frac{k}{k_s}\right) - 1\right] ln\left(\frac{r_s}{r_w}\right)$

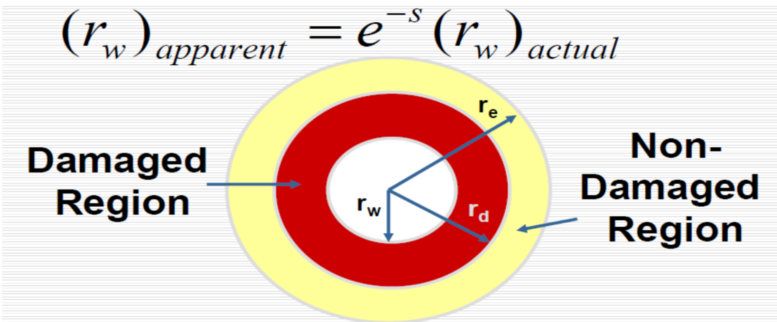

Figure 2. Damaged and Non-Damaged Region

1.2 Causes of formation damage

(i) Fluid/rock incompatibility;
(ii) fluid/fluid incompatibility;
(iii) departure from laminar, radial flow in an homogeneous, isotropic medium;
(iv) mechanical deformation around the borehole or perforation tunnels;
(v) reduction of fluid pressure during production.

1.2.1Near-wellbore permeability reduction caused by fluid/fluid incompatibility

Not infrequently, serious well productivity problems can be attributed to incompatibility of fluids. Incompatibility may arise between introduced fluids and reservoir pore-fluid (*e.g.* emulsion blocks produced by mixing mud acid and some crude oils, scale) or between fluids introduced into the well (e.g. between various additives in a chemical stimulation package).

Incompatibility of introduced fluids can be avoided by careful treatment design and quality control. Incompatibility of reservoir fluid and introduced fluid may be controlled by use of preflush/afterflush techniques and limitation of residence time in the reservoir (but may be rendered only partially effective by irregular distribution of fluids or reactive rock in the near-wellbore region).

Introduced solids may also occasionally be chemically incompatible with reservoir fluids.

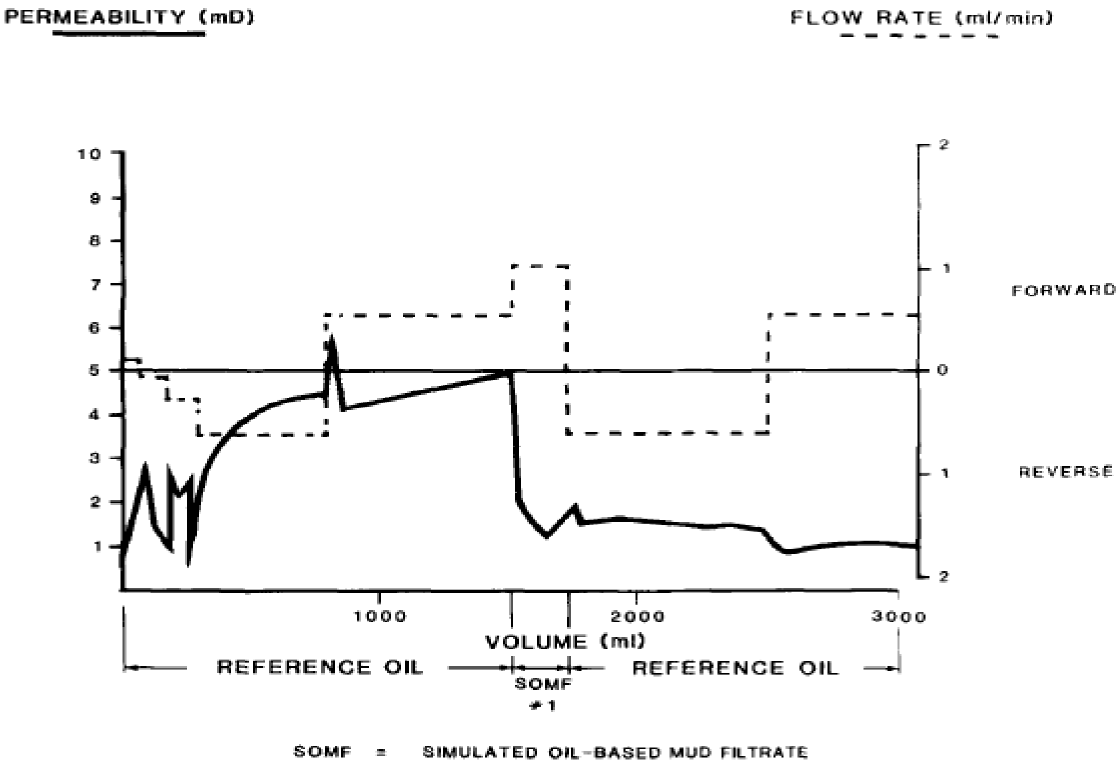

Figure 1 Damage incurred in laboratory lore test by flow of off-based mud filtrate

1.2.2 Departure from radial flow in an homogenous, isotropic medium

Skin factor, as originally derived, is related to the departure from radial flow in a homogeneous, isotropic medium. A positive skin may arise from a reduction of the area available to flow and/or a departure from purely radial flow. This could be caused by anisotropy (typically by bedding so that horizontal and vertical permeabilities differ) or heterogeneity.

1.2.3 Mechanical deformation around a borehole or perforation tunnel

Erosion of the wellbore during drilling leads to an excessively thick cement sheath in the resulting out-of-gauge hole. This limits or precludes penetration of perforation tunnels into the reservoir, and increases the volume of cement filtrate (which may be incompatible with the reservoir rock). The development of out-of-gauge holes is a function of rock strength, drill string behavior, mud characteristics, drilling time and *in situ* stress state.

Positive skins may also be generated by the creation of a crush zone around a perforation. When a jet produced by a shaped charge perforator enters the reservoir rock, the rock is displaced to one side of the jet. Crushing occurs in some rocks, forming a zone of low permeability around the perforation tunnel.

Both wellbore enlargement and perforation crush zone formation are purely or primarily a mechanical form of formation damage. They are well known. There is, however, an additional mechanical factor which does not appear to have been recognized previously as a potential cause of formation damage. Around any opening, such as a wellbore or perforation tunnel, the deviatoric stresses in a reservoir are concentrated so that local increases of stress difference occur. This may result in failure, giving rise to wellbore breakouts or sand production, in which case there exist some volumes of the material which have not failed but where conditions are close to failure.

1.2.4 Near-wellbore permeability reduction associated with production operations

A reduction of pressure (and also temperature) is associated with flow to a well. In the reservoir, this occurs primarily within the near-wellbore region. Associated with this are well-known adverse effects which can cause well productivity impairment, including the formation of gas blocks or liquid blocks, waxing, scale deposition, deposition of asphaltenes and fines migration. The pressure drop may not be entirely detrimental, however, as the Mohr stress circle is displaced away from the rock failure envelope, the pore pressure around openings is reduced during production.

1.3 Formation damage during well operations

Formation damage can occur whenever non-equilibrium or solid bearing fluid enters a reservoir, or when equilibrium fluids are displaced at extreme velocities. Thus many processes used to drill, complete or stimulate reservoirs have the potential to cause formation damage. Some of these operations are:

1.3.1 Drilling

- Mud solids and particle invasion
- Pore throat plugging
- Particle movement
- Mud filtrate invasion
- Clay swelling, flocculation, dispersion and migration
- Fines movement and plugging of pore throats
- Adverse fluid-fluid interaction resulting in either emulsion/water block, or organic scaling.
- Alteration of pore structure near wellbore through drill bit action.

1.3.2 Casing and cementing

- Blockage of pore channels by cement or mud solids pushed ahead of cement.
- Adverse interaction between chemicals (spacers) pumped ahead of cement and reservoir minerals fluid.
- Cement filtrate invasion with resulting scaling, clay slaking, fines migration and silica dissolution.

1.3.3 Completion

- Excessive hydrostatic pressure can force both solids and fluids into the formation.
- Incompatibility between circulating fluids and the formation with resultant pore plugging.
- Invasion of perforating fluid solids and explosives debris into the formation with resultant pore plugging.
- Crushing and compaction of near wellbore formation by explosives during perforation.
- Plugging of perforation of extraneous debris (mill scale, thread dope and dirt).
- Wettability alteration from completion fluid additives.

1.3.4 Well servicing

- Problems similar to those that can occur during completion.
- Formation plugging by solids in unfiltered fluids well killing.
- Adverse fluid-fluid and fluid-rock interaction between invading and kill fluid and reservoir minerals.
- Damage to days from dumping of packer fluids.

1.3.5 Well stimulation

- Potential plugging of perforations, formation pores and fractures from solids in the well kill fluid.
- Invasion of circulation fluid filtrates into the formation with resultant adverse interaction.
- Precipitation of hydrofluoric acid reaction by-products during acidizing.
- Potential release of fines and collapse of formation during acidizing.
- Precipitation of iron reaction products.
- Plugging of pores and fractures by dirty fracture liquids.
- Inadequate breakers for high viscosity fracture fluids may cause blockage of propped fracture.
- Fluid loss or adverting agents may cause plugging of perforation, formation pores, or propped fracture.
- Crushed propants may behave like migratory fines to plug the fracture.

1.3.6 Production

- Initiation of fines movement during initial DST by using excessive drawdown pressures.
- Inorganic/organic scaling through abrupt shift in thermodynamic condition.

1.4 Formation Damage in Horizontal Wells

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.

In the last few years, many horizontal wells have been drilled around the world. The major purpose of a horizontal well is to enhance reservoir contact and thereby enhance well productivity, which is highly desirable for enhanced oil recovery (EOR) applications.

In general, a horizontal well is drilled parallel to the reservoir bedding plane. Strictly speaking, a vertical well is a well which intersects the reservoir bedding plane at 90°. In other words, a vertical wells is drilled perpendicular to the bedding plane.

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.

In general, the drilling related damage in high permeability reservoir is smaller than that in low permeability reservoir. For the skin damage value, the influence of damage on horizontal well productivity is not as detrimental as in a vertical. Thus horizontal wells can sustain more damage than vertical wells without a significant loss of well productivity. However, due to additional drilling time incurred in horizontal wells, horizontal wells may show much more near wellbore damage than a vertical well and a proper procedure must be adopted to minimize this severe damage or to clean up this damage.

1.5 Mechanism of formation damage in 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 movement of existing particulate matter already in the pore system. This may be caused during the drilling process by high fluid leak off rates of mud filtrate into the near wellbore region caused by high hydrostatic overbalance pressures or too high underbalanced pressures.

External Drilling/Mud Solids Invasion: The invasion of artificial drilling agents (weighting agents, fluid loss agents or bridging agents), or mud solids naturally produced by interaction between the drilling bit and rock and not removed by surface solids control equipment into the formation during overbalanced drilling conditions.

Phase Trapping: This is the loss of both water or oil based drilling mud filtrate to the formation in the region near the wellbore due to leakoff occurring as a result overbalanced drilling operations, or due to spontaneous imbibition which can occur during underbalanced drilling operations, can result in permanent trapping 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 very reactive material in-situ in the matrix, which include reactive swelling clays such as smectite or mixed layer clays, or deflocculatable materials such as kaolinite or other uncompacted fines.

Expansion or movement of these fines within the pore system, which are caused by the invasion of non-equilibrium water based mud filtrates into the near wellbore region, can cause substantial reductions in permeability.

Fluid-Fluid Incompatibility Effects between Invading Fluids and In-Situ Fluids: Oil or water based mud filtrates which invade into the near wellbore region when drilling in overbalanced conditions processes can react adversely with hydrocarbons or waters present in the matrix to form substances 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.

Wettability Alteration and Surface Adsorption Effects: Many additives in drilling fluids used for mud rheology, corrosion inhibition, stability, emulsion control, torque reduction or lubricity contain polar surfactants or compounds which can be adsorbed preferentially on the surface of the rock. The physical adsorption of these compounds can cause reductions in permeability by the physical blockage 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.

1.6 Why is formation damage more of a concern in horizontal versus vertical wells?

There are a many reasons why horizontal wells appear to be more susceptible to formation damage than vertical wells. One of the major reasons is related to the completion practices used for most horizontal wells. Most horizontal wells are completed in either a open hole fashion or with a slotted or prepacked liner, which, as far as produced fluids are concerned, is equivalent to an open hole completion. Compared 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 well bore 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, t the produced reservoir fluids must completely pass 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 damaged zone can 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 obvious in an open hole scenario. Other reasons contributing to increased severity of damage in horizontal versus vertical wells could include:

Greater Depth of Invasion: The drilling periods for horizontal wells are usually greater than that of conventional vertical wells. The time of exposure to the drilling fluid 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, depth of invasion 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 length of exposure of a horizontal well often results in zones of highly variable reservoir quality being penetrated. High permeability zones 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 effectual cleanup. Production logs on horizontal wells often indicate that majority of the produced fluid are drained from only a very small section of the total length of the well.

Difficulty of Stimulation: Damaged vertical wells can be stimulated economically by using a variety of techniques such as hydraulic or acid fracturing, acid or other types of chemical squeezes, heat treatments e.tc. These processes are not readily economically applied to horizontal wells due to cost and technical considerations associated with attempt-ting 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. A vertical well in 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 plane and hence is much more affected by variations in the vertical permeability of the reservoir.

1.7 Types of horizontal drilling

1.7.1 Short radius horizontal wells

Short radius horizontal wells are commonly used when reentering existing vertical wells in order to use the latter as the physical base for drilling of add-on arc and horizontal hole sections. The steel casing (lining) of an old vertical well facilitates attainment of a higher departure or "kick-off" angle than can be had in an uncased hole, so that a short radius profile can more quickly attain horizontality, and thereby rapidly reach or remain within a payzone. The small displacement required to reach a near-horizontal attitude also favours the use of short-radius drilling in small lease blocks. A need to avoid extending drilling in a difficult overlying formation also favors use of a short radius well that kicks off near the bottom of, or below, the difficult formation. Short radius horizontal drilling also has certain economic advantages. Build rates for short radius range from 1.5^o to 3^o per foot (4.920^o to 9.840^o per meters). The dogleg severity is from 150^o to 300^o/100 feet (492.130^o to 984.250^o/328.080 per meters). These include a lower capital cost and the fact that the suction head for down hole production pumps is smaller, and that use of an MWD system is frequently not required if long horizontal sections are not to be drilled .

A current drawback to the use of a short radius horizontal well is that the target formation should be suitable for an open hole or slotted liner completion, since adequate tools do not yet exist to reliably do producing zone isolation, remedial, or simulation work in short radius holes. Also, hole diameter can only range up to 6 inches, and the hole cannot be logged since sufficiently small measurement tools are not yet available [23].

1.7.2 Medium horizontal wells

Medium horizontal wells allow the use of larger hole diameters, near conventional bottom hole (production) assemblies, and more sophisticated and complex completion methods. It is also possible to log the hole. Albeit that the drilling of medium-radius horizontal wells does require the use of an MWD system, which increases drilling cost, 19 medium-radius holes are perhaps the most popular current option.

1.7.3 Long radius horizontal wells

Long radius horizontal wells can be drilled using either conventional drilling tools and methods, or the newer steerable systems. Long radius wells, in the form of deviated wells (not however deviated to the horizontal) have been around quite a while. They are not suited to leases of less than 160 acres due to their low build rates.

1.8 Sources of information available for damage diagnosis

Drilling, completion and workover records: These represent the basic record of engineering operations. They form a basis for the initial identification of possible problems (*e.g.* drilling difficulties, use of loss agents, nature of perforation, dirty kill fluid). They also provide the framework for designing laboratory tests to assess potential damage (e.g. fluid/rock compatibility, fluid/fluid compatibility).

Well tests: Pressure transient analysis is the conventional oil industry method for identifying any impairment of well productivity, which is conventionally quantified in terms of a skin factor. As such, well tests are the cornerstone of the information available not only to detect formation damage, but to quantify the effect. In addition, the productivity index of a well (or, alternatively, injectivity index), measured during a period of flow, is a clear measure of well performance, and incorporates the skin factor.

Open hole or production logs: Wireline logs in the open hole can be used to indicate such features as out-of-gauge wellbores and wellbore breakout, fluid invasion depth, stratigraphy, and natural fractures.

Commonly available, they can be used to check for potential problems such as an oversize cement sheath. Cased hole logs can be used to some extent to detect flow distribution after a stimulation treatment, and other factors relating to well performance such as the cement bond (poor cement jobs may give rise to positive skins because of cross flow behind the casing).

Production records: Trends of production performance may give clues to progressive changes associated with damaging processes such as waxing or scaling, or to the effects of workovers.

Reservoir petrology: Petrological studies provide a basic description of the porous rock morphology and mineral content. These must be related to the engineering performance of the rock if the description is to adopt a more positive role than that of pertinent background information.

While the factors governing the relationship between the type, content, morphology and distribution of minerals in an argillaceous material and response of that porous medium to fluid flow and changes of pore-fluid electrochemistry have not been defined, the potential value of a petrological description is necessarily limited. Many authors have attempted to classify formation damage potential on the basis of petrological descriptions (e.g., most recently, [21]). We regard such proposals as speculative until supported by the results of laboratory flow investigations.

Detailed reservoir structure: Whilst open fractures are known to assist well productivity, and are associated with negative skin factors, it is less well known that filled fractures can give rise to a positive skin [22]. This is sometimes termed a 'pseudoskin', which may be mistaken for formation damage induced by another process.

Sedimentary features of the reservoir: A positive skin may result simply from the layering associated with sedimentation. Either unequal bedding-parallel or bedding-normal permeabilities, or the influence of low permeability layers on flow to the perforations, may be responsible. Heterogeneities of the sedimentary sequence other than the latter can also give rise to positive skin factors.

Mechanical tests of core samples: Rock mechanical tests can sometimes be of value, such as to assess rock strength when wellbore enlargement is suspected, or strength reduction after acidizing a core. A variety of mechanical property indexing methods are available. Use of a hardness value has the merit of requiring only small test samples.

1.9 Effects of formation damage on well productivity

It is divided into two sections:

- The use of Joshi equation to determine how the productivity of horizontal changes with effect of skin in different horizontal well configurations such as variable pay thickness and reservoir anisotropy.
- The use of industry based software to model vertical and horizontal wells, analyzing the changes in their productivity with different skin values.

1.9.1 Effects of formation damage on the productivity of horizontal wells

As part of selectively analyzing the models, the various effects of the previously listed reservoir parameters are going to be evaluated and analyzed, looking at the numerous ways by which they affect productivity index.

Reservoir thickness (h): As previously stated, horizontal wells are more productive in thin reservoirs, as a result of the larger contact area the well makes with the reservoir. Hence higher reservoir thickness implies that the area contacted by the wellbore would be appreciably lower, compared to thin reservoirs. However, lower contact are, implies lower reservoir productivity.

Permeability (k): There are two types in every reservoir; they are the horizontal permeability and the vertical permeability. Permeability however, is the ability of a reservoir rock to transmit fluids. They can be used to describe a reservoir in terms of isotropy and anisotropy.

Isotropic reservoir is that in which the horizontal permeability (k_h) is equal to the vertical permeability (k_v). Anisotropic reservoir is that in which the horizontal permeability is not equal to the vertical permeability.

Length of the horizontal well: Research has shown that as the length of a horizontal well increases, its contact area with the reservoir also increases, hence there is increase in productivity index, but at the same time, the resistance to the flow in a well also increases (friction and other pressure drops), which has a direct negative effect on the PI. This implies that initially, increase in the well length of a well leads to increase in productivity index, but it reaches a point in which, an additional increase in the length, would result in a productivity drop, due to the effect of numerous pressure drop. The overall performance of a horizontal well depends on the balance of these two opposing factors.

This project aims to study the effect of formation damage on the productivity of horizontal wells. To achieve this we have to look at the various methods for predicting the productivity index of horizontal wells.

2. Productivity index (PI) prediction

In case of a "wildcat" well, some data on reservoir permeability (k) and thickness (h) can be obtained from offset wells. Then the well spacing, well bore size and fluid type and the estimated k_h can be used in the radial flow equation to calculate the *PI.*

$$PI = \frac{q_0}{P_w - P_{wf}} = \frac{0.00708LK_h}{\mu_o B_o ln\left(\frac{r_e}{r_w}\right)} \quad (1)$$

With this, the inflow performance of the well can be predicted. A higher *PI* shows a better inflow performance. *PI* of the well under zero skin condition is called ideal *PI*. When skin occurs, there is a deviation from normal condition due to skin either caused by drilling or by completion practices. In fact, it is difficult to obtain an ideal condition and, therefore, *PI* ideal can only be calculated.

In many oil and gas wells, the observed flow rate is different from that calculated theoretically. The concept of skin was developed to account for deviation from the theoretical rate. During pseudo steady state flow, the oil flow rate can be calculated as:

$$q = \frac{0.00708kh(P_w - P_{wf})}{\mu_o B_o ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S_T} \ldots \quad (2)$$

where S_T is the total skin factor, which includes the effect of partial penetration, perforation density's well stimulation, mechanical skin damage due to drilling and completion, etc. A positive value of S_T would result in a reduction of flow rate while a negative value of S_T would result in flow enhancement.

The mechanical skin factor (S_m) represents well drainage caused by drilling and completion fluid. The change in well *PI* to these parameters is described by assigning an equivalent skin factor called Pseudo skin factor.

For a partially penetrating well,

$$S_T = \frac{S_m}{b^t} + S_P \qquad (3)$$

where, S_m = mechanical skin factor; S_p = pseudo skin factor caused by partial penetration; b_t = penetration ratio.

For horizontal wells, performance prediction is less straightforward. The problem is complicated by the effect of boundary conditions on the type of drainage that results from the influx towards the well. Merkulov and later Borisov presented analytical expressions for horizontal wells producing under ideal conditions of isotropic reservoirs with no formation damage and no friction. Joshi studied the same problem extended to three dimensional steady state flow with relatively short horizontal wells compared to the drainage area which is assumed to be elliptical. Giger generalized the results to a rectangular area to account for longer horizontal wells using the potential flow theory. Other investigators like Economides and Renard and Dupuy did more work to take into account the anisotropy ratio and contributed in developing the theoretical expression of the productivity index as it is now accepted as reported by Economides. The steady state analytical solution is the simplest solution to various horizontal well problems; the steady state solution requires that the pressure at any point in the reservoir does not change with time. The flow rate equation in a steady state condition is represented by

$$J = \frac{Q_{oh}}{\Delta P} \ . \qquad (4)$$

where: Q_{oh} is the horizontal well flowrate, STB/day; ΔP is the pressure drop from drainage boundary to wellbore, psi; J is the productivity index of the horizontal well, STB/day/psi.

2.1 Borisov's model

Borisov proposed the following expression for predicting the productivity index for a horizontal well in an isotropic reservoir, *i.e.*, k_v=k_h the physical properties of the reservoir does not vary with direction.

$$J_h = \frac{0.00708hK_h}{\mu_o B_o\left(ln\left(\frac{4re_h}{L}\right)+\left(\frac{h}{L}\right)ln\left(\frac{h}{2\pi r_w}\right)\right)} \qquad (5)$$

where: H is the thickness, ft; K_h is the vertical permeability, md; K_v is the vertical permeability, md; L is the length of the horizontal well, ft; R_w is the wellbore radius, ft; Re_h is the drainage radius of the horizontal well, ft; J_h is the productivity index, STB/day/psi.

2. 2 The Renard Dupuy model

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

$$J_h = \frac{0.00708hK_h}{\mu_o B_o\left(cosh^{-1}\left(\frac{2a}{L}\right)+\left(\frac{h}{L}\right)ln\left(\frac{h}{2\pi r_w}\right)\right)} \qquad (6)$$

where a is half the major axis of drainage ellipse and given by the equation

$$a = \left(\frac{L}{2}\right)\left(0.5 + \sqrt{0.25 + \left(\frac{2re_h}{L}\right)}\right)^{0.5} \qquad (7)$$

For anisotropic reservoirs, the authors proposed the following relationship

$$J_h = \frac{0.00708hK_h}{\mu_o B_o\left(cosh^{-1}\left(\frac{2a}{L}\right)+\left(\frac{Bh}{L}\right)ln\left(\frac{h}{2\pi r_w{}'}\right)\right)} \qquad (8)$$

where, $r_w' = \frac{(1+B)r_w}{2B}$ ... (9)

2. 3 JOSHI'S model

$$J_h = \frac{0.00708hK_h}{\mu_o B_o\left(ln(R)+\left(\frac{h}{L}\right)ln\left(\frac{h}{2r_w}\right)\right)} \ldots \tag{10}$$

With

$$R = \frac{a+\sqrt{a^2-\left(\frac{L}{2}\right)^2}}{\left(\frac{L}{2}\right)} \tag{11}$$

where a is half the major axis of drainage ellipse and given by the equation

$$a = \left(\frac{L}{2}\right)\left(0.5 + \sqrt{0.25 + \left(\frac{2re_h}{L}\right)}\right)^{0.5} \tag{12}$$

Joshi accounted for the influence of the reservoir anisotropy by introducing the equation

$$J_h = \frac{0.00708hK_h}{\mu_o B_o\left(ln(R)+\left(\frac{B^2h}{L}\right)ln\left(\frac{h}{2r_w}\right)\right)} \tag{13}$$

where the parameters B and R are defined above.

2. 4 The Giger Reiss Jourdan model

The Giger model takes into consideration that for an isotropic reservoir where the vertical permeability k_v equals k_h, Giger et al. proposed the following expression for determining J_h

$$J_h = \frac{0.00708LK_h}{\mu_o B_o\left(\left(\frac{h}{L}\right)ln(X)+ln\left(\frac{h}{2r_w}\right)\right)} \tag{14}$$

$$X = \frac{1+\sqrt{1+\left(\frac{L}{2r_{eh}}\right)^2}}{\frac{L}{2r_{eh}}} \ldots\ldots \tag{15}$$

To account for the reservoir anisotropy, the authors of this model proposed the following relationships:

$$J_h = \frac{0.00708K_h}{\mu_o B_o\left(\left(\frac{1}{h}\right)\ln(X)+\left(\frac{B^2}{L}\right)ln\left(\frac{h}{2rw}\right)\right)} \tag{16}$$

The B parameter was defined as

$$B = \sqrt{\frac{K_h}{K_v}} \tag{17}$$

Where: K_v is the vertical permeability, md;L is the length of the horizontal section ft.

In this project the following equations are going to be used for calculations and analysis:

For horizontal well with isotropic reservoirs

$$q_h = \frac{0.00708k\Delta p}{\mu_o B_o\left(ln\left(\frac{a+\sqrt{a^2-\left(\frac{L}{2}\right)^2}}{\left(\frac{L}{2}\right)}\right)+\left(\frac{h}{L}\right)ln\left(\frac{h}{2r_w{}'}\right)\right)} \ldots \tag{18}$$

$$J_h = \frac{0.00708hK_h}{\mu_o B_o\left(ln(R)+\left(\frac{h}{L}\right)ln\left(\frac{h}{2r_w}\right)\right)} \tag{19}$$

$$R = \frac{a+\sqrt{a^2-\left(\frac{L}{2}\right)^2}}{\left(\frac{L}{2}\right)} \tag{20}$$

$$a = \left(\frac{L}{2}\right)\left(0.5 + \sqrt{0.25 + \left(\frac{2re_h}{L}\right)}\right)^{0.5} \quad (21)$$

For horizontal well accounting for the influence of anisotropy

$$J_h = \frac{0.00708hK_h}{\mu_o B_o\left(ln(R) + \left(\frac{B^2h}{L}\right)ln\left(\frac{h}{2r_w}\right)\right)} \dots \quad (22)$$

To account for the presence of skin, the wellbore with normal radius of r_w therefore, with a skin effect present, has a reduced wellbore radius which is the effective wellbore radius r_w' which is given by $rw'=r_w \exp(-S)$.

This new wellbore radius due to skin can be incorporated into the formula to give

$$J_h = \frac{0.00708hK_h}{\mu_o B_o\left(ln(R) + \left(\frac{B^2h}{L}\right)ln\left(\frac{h}{2r_{w'}}\right)\right)} \quad (23)$$

3. Data Analysis and Results

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. 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 vertical to horizontal permeability ratio is increased.

3.1 Effect of well length and permeability on productivity index

This result as shown in table 1 shows that PI increases with increasing lateral length. Thus, longer horizontal well length enhances productivity. This is explained by the fact that a large portion of the reservoir has been contacted and the pressure drop along the well bore is reduced, thereby enhancing productivity. In the case of anisotropy it shows that horizontal wells are more suitable for reservoirs with high vertical permeability (K_v) as this increases horizontal well PI.

Table 1 Length vs productivity index with variation in anisotropy ratio

Length	Productivity Index		
	k_v/k_h=0.1	k_v/k_h=0.5	k_v/k_h=1
100	2.15	3.13	3.46
500	5.58	6.66	6.92
900	8.19	9.45	9.73
1300	10.94	12.39	12.68
1700	14.02	15.978	16.47

3.2 Effect of skin damage in horizontal versus vertical wells

This Table provides the results of the calculations on horizontal and vertical well geometries using identical reservoir parameters (This data is based on isotropic (equal) horizontal and directional permeabilities. Figure 4 illustrates the horizontal and vertical well normalized productivity in a low skin factor (S = 0-10) regime, and Figure 5 at the range of skin factors up to 500. This data shows that the horizontal well suffers less relative productivity reduction than the equivalent vertical well, this due to greater length and reservoir exposure (in this geometry)., it also shows that at extreme skin factors (which may occur in a badly damaged overbalanced open hole completion) that the horizontal well productivity is reduced to only 14% of the original value (in comparison to the vertical well whose productivity is reduced to 1.5% of the initial value).

Table 2 Skin factor vs normalised flowrate

skin factor	Q-norm (vertical well)	Q –norm (horizontal well)	skin factor	Q-norm (vertical well)	Q –norm (horizontal well)
0	1	1	20	0.275	0.802
1	0.884	0.988	50	0.132	0.619
2	0.792	0.976	100	0.071	0.448
5	0.603	0.942	200	0.037	0.288
10	0.432	0.89	500	0.015	0.14

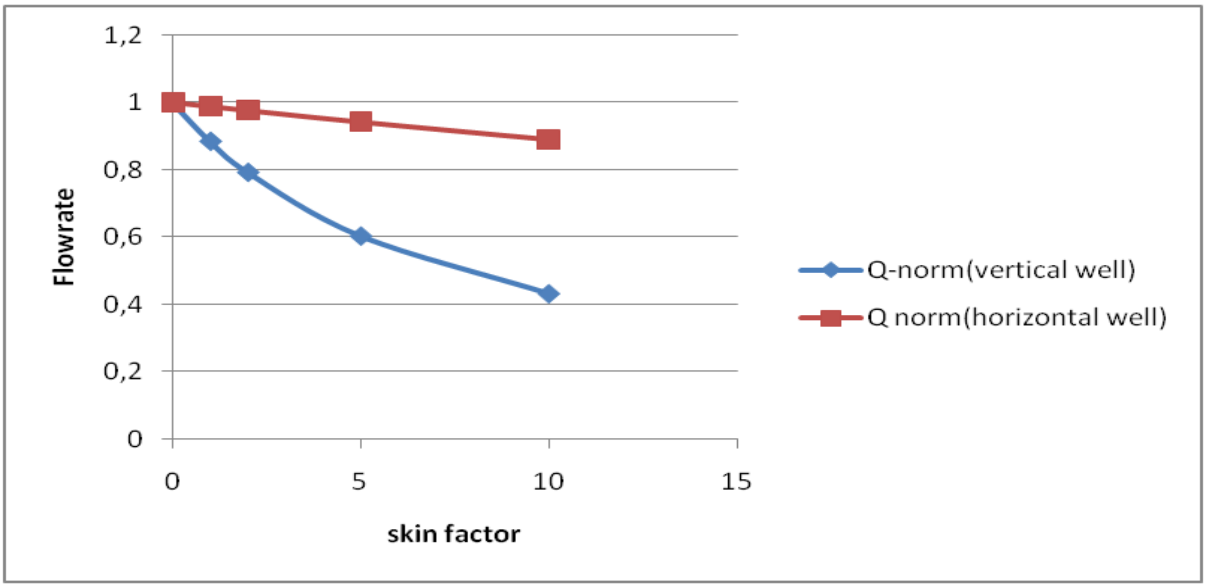

Figure 4 Flowrate against skin factor (at low skin values)

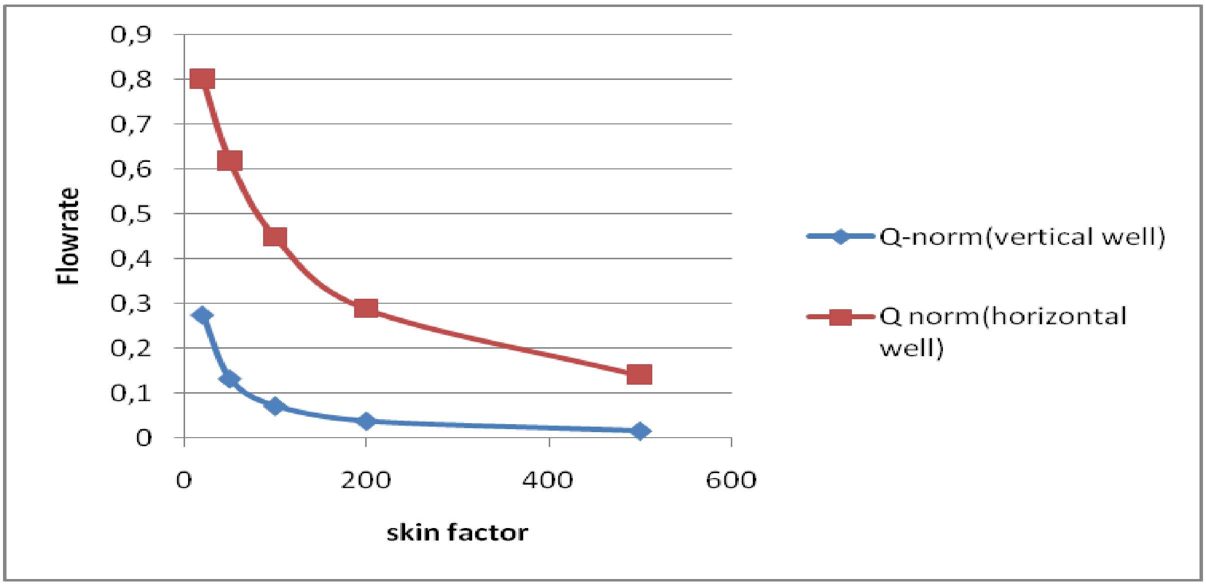

Figure 5 Flowrate against skin factor (at extreme skin values)

3.3 Comparison of horizontal to vertical well performance in zones of isotropic permeability but variable pay thickness

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. 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).

Table 3 Skin factor vs vertical and horizontal length

skin factor	vertical well h=2m	horizontal well h=2m	vertical well h=10m	horizontal well h=10m	Vertical well h=50m	Horizontal well h=50
0	1	1	1	1	1	1
1	0.884	0.997	0.884	0.985	0.884	0.919
2	0.792	0.994	0.792	0.97	0.792	0.85
5	0.603	0.984	0.603	0.929	0.603	0.694
10	0.432	0.969	0.432	0.868	0.432	0.532

3.4 Comparison of horizontal to vertical well performance in reservoir zones of anisotropic permeability

These conditions are 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.

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.

Table 4 Skin factor vs anisotropy ratio

skin factor	vertical well	k_v/k_h=0.1	K_v/k_h=0.01	K_v/k_h=0.001	k_v/k_h=10	k_v/k_h=1000
0	1	1	1	1	1	1
1	0.884	0.965	0.917	0.851	0.996	1
2	0.792	0.933	0.846	0.74	0.992	0.999
5	0.603	0.848	0.687	0.532	0.98	0.998
10	0.432	0.735	0.524	0.363	0.962	0.996

3.5 Use of industry based software 'Prosper'

Prosper was used to simulate the change in the productivity of the well with different skin values. Here is a summary of the result.

Table 5 Skin factor vs AOF (Stb/Day) using Prosper

Skin Values	AOF(STB/day)	
	Vertical Well	Horizontal Well
0	5535.9	7664
5	3213.3	6761.8
10	2263.6	6049.7

Results showed that:

- At the same values of skin, the horizontal well gives a higher productivity value than the vertical well.
- As the skin increases the productivity of the well is reduced.
- For the skin damage value, the influence of damage on horizontal well productivity is not as detrimental as in a vertical.

4. Conclusion

1. 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.
2. This project also proves that horizontal wells can sustain more damage than vertical wells without a significant loss of well productivity.
3. 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 underbalanced pressure condition is maintained.

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