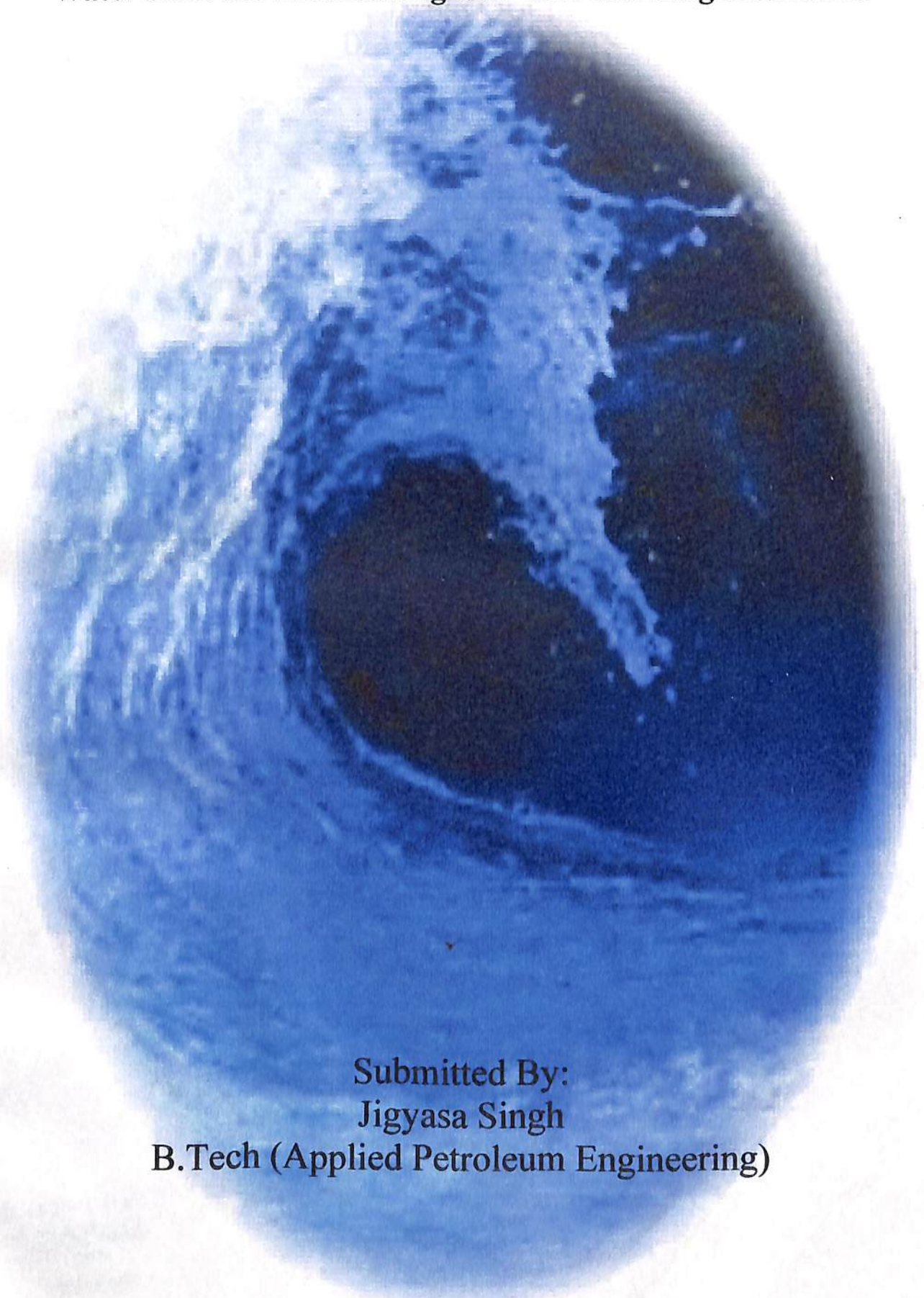


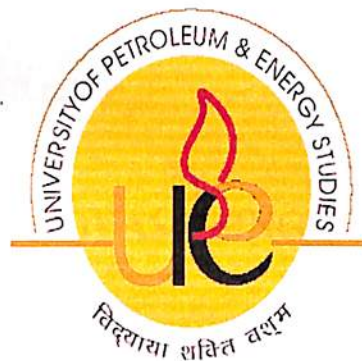
Water Shut-Off in Producing Oil Fields and Diagnostic Plots



Submitted By:
Jigyasa Singh
B.Tech (Applied Petroleum Engineering)

WATER SHUT-OFF IN PRODUCING OIL FIELDS AND
DIAGNOSTIC PLOTS

By
JIGYASA SINGH



College of Engineering
University of Petroleum & Energy Studies
Dehradun
May, 2008

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**WATER SHUT-OFF IN PRODUCING OIL FIELDS AND
DIAGNOSTIC PLOTS**

A thesis submitted in partial fulfilment of the requirements for the Degree
of
Bachelor of Technology
(Applied Petroleum Engineering)

By
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Under the guidance of

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May, 2008

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CERTIFICATE

This is to certify that the Project Report on “**Water Shut-Off in Producing Oil Fields and Diagnostic Plots**” submitted to University of Petroleum & Energy Studies, Dehradun, by Ms. Jigyasa Singh in partial fulfillment of the requirement for the award of Degree of Bachelor of Technology in Applied Petroleum Engineering (Academic Session 2004 - 08) is a bonafide work carried out by her under my supervision and guidance. This work has not been submitted anywhere else by anyone for any other degree or diploma.

Date: 15.05.2008



DR. A.K. CHOUBEY
Assistant Professor

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Chapter – 1

Introduction

“Owing to the fact that a daily water production of roughly 210 m bbl (33.4 MMcu) of water accompanies every 75 m bbl (11.9 MMcu) of oil, many oil companies could almost be called water companies”.

Water production is the harbinger of problem in an oil well. It can cause scaling problem in susceptible wells, induce fines migration or sandface failure, increase corrosion of tubular and kill well by hydrostatic loading. Hence, it is desired to defer the onset of water production for as long as possible.

The high water production in oil wells causes major economic and operational problems for several reasons. It decreases oil production, and results in large amounts of produced water that need to be disposed. It also requires increased capacity of water separation and handling facilities. Other production related problems include high corrosion rates and increased tendency for emulsion and scale formation. Therefore, there is a need to reduce water production. Several mechanical and chemical methods are available for water shut-off treatment. However, the choice of a specific treatment depends on the source of water production, well characteristics, and cost. There are various ways to control this water production such as: mechanical, chemical and downhole separation methods. Water shut-off treatments using chemical means include injection of a gelling solution which is one of the most frequently used methods. The gelant solution is composed of hydrolyzed Polyacrylamide polymer and organic cross-linkers (Hexamine and Hydroquinone) or inorganic cross-linkers like chromium acetate [chromium (III)].

1.1 Scope of Present Study

Production of water along with oil is perhaps one of the most commonly faced problems in the oil industry. This water may be getting produced due to a number of reasons ranging from leakages, fractures to aging of the well. Studies were carried out to optimize the polymer gel solution for water shut off process for field applications by evaluating a number of gel formulations of various combinations at reservoir temperature. This was followed by core flood experiment to know how the optimized gel works under actual field conditions. This evaluation is necessary to conclude whether the optimized gel can be actually applied in the oil field.

The work carried out in the study can be classified under the two major objectives:

- To get an optimized gel formulation using polymer Alcoflood-955 with organic cross linkers, stable at Beta reservoir temperature of 105°C and compatible with formation water by extensive laboratory experimentations for field applications for controlling water production.
- To evaluate the effectiveness of the optimized polymer gel system on native cores of Beta reservoir by Core flood studies.

The project related experiments were conducted in the Institute of Reservoir Studies, a renowned institute of Oil and Natural Gas Corporation, an oil E&P company of India.

Chapter – 2

Water Control

“Owing to the fact that a daily water production of roughly 210 m bbl (33.4 MMCu) of water accompanies every 75 m bbl (11.9 MMCu) of oil, many oil companies could almost be called water companies”. Water handling costs are high ranging from 5 to more than 50 cents per barrel of water. Cost of water handling can be as high as \$ 4 per barrel of oil produced in well producing oil with an 80% water cut. Water affects every stage of oilfield life from exploration through development, production and finally to abandonment.²

As oil is produced from reservoir water from an underlying aquifer or water injection wells will eventually be mixed a produced along with the oil. This movement of water through a reservoir into production tubing and surface production facilities and eventually extracted for disposal or injected for pressure maintenance is called water cycle.

2.1 Produced Water

In subsurface formations, naturally occurring rocks are generally permeated with fluids such as water, oil, or gas (or some combination of these fluids). It is believed that the rock in most oil-bearing formations was completely saturated with water prior to the invasion and trapping of petroleum .The less dense hydrocarbons migrated to trap locations, displacing some of the water from the formation in becoming hydrocarbon reservoirs. Thus, reservoir rocks normally contain both petroleum hydrocarbons (liquid and gas) and water. Sources of this water may include flow from above or below the hydrocarbon zone, flow from within the hydrocarbon zone, or flow from injected fluids and additives resulting from production activities. This water is frequently referred to as “connate water” or “formation water” and becomes produced water when the reservoir is produced and these fluids are brought to the surface.

Produced water thus is any water that is present in a reservoir with the hydrocarbon resource and is produced to the surface with the crude oil or natural gas. When hydrocarbons are produced, they are brought to the surface as a produced fluid mixture and this fluid generally includes a mixture of either liquid or gaseous hydrocarbons, produced water, dissolved or suspended solids, produced solids such as sand or silt, and injected fluids and additives that may have been placed in the formation as a result of exploration and production activities.

2.2 Water Sources

Water is present in every oil field and is the most abundant fluid in the field. When it comes to producing oil we need to have a clear distinction between three kinds of water we encounter

- Sweep,
- Good (acceptable) and
- Bad (excess) water

Sweep water comes from either an injection well or an active aquifer that is contributing to the sweeping of oil from the reservoir. The management of this water is a vital part of reservoir management and can be a determining factor in well productivity and the ultimate reserves.

Good Water is the water that is produced into the well bore at a rate below the economic WOR (Water Oil Ratio). It is an inevitable consequence of water flow through the reservoir and it cannot be shut off without losing our reserves. Good water production occurs when the flow of oil and water is commingled through the formation matrix. Another form of acceptable water production is caused by converging flow lines into the well bore. For example, in a quadrant of a five-spot injection pattern, an injector feeds a producer. Flow from the injector can be characterized by an infinite series of flow lines. The shortest is the straight line from injector to producer and the longest follows no flow boundaries between the two. Water breakthrough occurs initially along the shortest flow line while oil is still produced along the longer flow lines. This water must be considered good since it is not possible to shut off selected flow lines while allowing others to produce. Since good water by definition produces oil with it, water management should seek to maximize its production. To minimize associated water costs the water should be removed as early as possible, ideally with a downhole separator.

Bad Water can be defined as the water produced into the well bore which produces no oil or insufficient oil with it to pay for the cost of handling the water, that is this water is produced above the economic limit.

2.3 Types of Water Problems

Water breaks through in well due to various reasons. To know the exact cause is the key to treat the problem well. The basic problems associated with produced water can be enumerated as: -

1. Casing tubing or packer leaks

Leaks through casing tubing or packers, allows water from non oil productive zones to enter the production string. Basic production logs such as fluid density, temperature and spinner may be sufficient to diagnose these problems. In more

complex wells water flow logs (WFL) or multiple fluid logging such as three phase fluid holdup log (TPHL) can be valuable. Tools with electrical probes such as flow view tool can identify small amounts of water in the production flow.

Solution to these problems include

- squeezing shut off fluid
- mechanical shut off using plugs, cement and packers
- casing patches can also be used

All solutions applied are based on low cost, inside casing water shut off technology.

2. Channel flow behind casing

If primary cement job fails by any chance, it can connect water bearing zones to the pay zone. These channels allow water to flow behind casing into the annulus. A secondary cause can be the creation of a void behind the casing as sand is produced. Temperature logs or oxygen activation based WFL can detect this water flow. The main solution is the use of shut off fluid placed in the formation to stop flow into the annulus. Placement is critical and generally is achieved with the help of coiled tubing.

3. Moving Oil Water Contact

A uniform oil water contact or OWC moving up through a perforated zone in a well during normal water driven production can lead to unwanted water production. This happens generally in the case of low vertical permeability. Since the flow area is large and the rate at which contact rises is low, it can even occur at extremely low intrinsic vertical permeability (less than 0.01 md). In case of higher vertical permeability ($K_v > 0.01 K_H$), coning and other problems are more likely to be present. Infact this problem type could be considered as a subset of coning but the coning tendency is so low that near well bore shut off is effective. Diagnosis cannot be based solely on known entry of water at the bottom of the well since other problems also cause this behavior. In a vertical well, this problem can be solved easily by abandoning the well from the bottom using mechanical devices like cement or bridge plug set on wireline. Treatment needs to be repeated if OWC moves significantly past the top of the plug. In vertical wells, this problem is the first under the classification systems and it extends beyond the local wellbore environment. In horizontal wells, any wellbore or near wellbore solutions must extend far enough uphole or downhole from the water producing interval to minimize horizontal flow of water past the treatment zone and delay subsequent water breakthrough.

4. Watered out layer without crossflow

A common problem with the multilayered production occurs when a high permeable zone with a flow barrier above and below is watered out. The watered out layer has

the highest permeability. In the absence of reservoir crossflow, this problem is easily solved by the application of rigid shut off fluids or mechanical shutoff in either injector or producer. Choice between placement of a shutoff fluid or a mechanical shutoff system depends on which interval is watered out. The absence of crossflow depends on the continuity of the permeability barrier. Horizontal wells comprising of single layer are not subjected to this kind of problem. Water problem in highly inclined wells completed in multiple layers can be treated in the same way as vertical wells.

5. Fractures or faults between injectors and producers

In naturally fractured formations under water flood, injection water can rapidly breakthrough into producing wells. This is common when the fracture system is extensive or fissured. Tracer logs can be used to quantify the fracture volume which is used for the treatment design. The injection of the flowing gel at the injector can reduce production without adversely affecting oil production. When crosslinked gels are used they can be bullheaded because they have limited penetration in the matrix and so selectively flow in the fractures (therefore they will flow only in high permeable zones). Water shutoff is usually the best solution for this problem.

Wells with severe fractures or faults often exhibit extreme loss of drilling fluids. If a conductive fault and associated fracture are expected during drilling, pumping flowing gels into the well may help solve both the drilling problem and the subsequent water production and poor sweep problems, particularly in formations with low matrix permeability. In horizontal well, the same problem can exist when the well intersects one or more faults that are conductive or have associated conductive fractures.

6. Fractures or faults from a water layer

Water can also be produced from fractures that intersect a deeper water zone. These fractures may be treated with a flowing gel. This is particularly successful where the fractures do not contribute to oil production. Treatment volumes must be large enough to shut off the fractures far away from the well.

However, three kinds of problems are generally faced during such treatments: -

- Treatment volume is difficult to determine because fracture volume is unknown.
- The treatment may shutoff oil producing fractures.
- If a flowing gel is used, it must be carefully tailored to resist flow back after treatment.

In cases of localized fractures it may be appropriate to shut them off near wellbore, specially if the well is cased and cemented. Degradation in production is caused when hydraulic fractures penetrate a water layer.

In many carbonate reservoirs, the fractures are generally steep and tend to occur in clusters that are spaced at large distances from each other, especially in tight dolomitic zones. Thus, the probability of these fractures intersecting a vertical wellbore is low. However, these fractures are often observed in horizontal wells where production is often through conductive faults that intersect an aquifer.

7. 2-D Coning: Horizontally fractured production wells³

When production wells are horizontally fractured, the fracture often unintentionally breaks into water zones, causing substantially increased water production. Gelant treatments have significant potential to correct this problem. These gelant treatments rely on the ability of gels to be placed in the rock matrix adjacent to the fractures and to reduce permeability to water much more than that to hydrocarbons (Disproportionate Permeability Reduction, DPR). In matrix rock treatments, gelants flow along the fracture and leak off a short, predictable distance into the matrix rock of all the zones (water, oil & gas). Success for such a treatment requires that a gel reduce permeability to water much more than to hydrocarbon in the treated matrix rock. *The ability of a gel to stop water entry into a fracture is determined by the product of gelant leak off distance (from the fracture face) and the residual resistance factor (permeability reduction factor) provided by the gel.* For example, consider the case in which gelants leak off 0.2 ft into both water and oil zones, and in the gel contacted rock, permeabilities to water and oil are reduced by factors of 50,000 and 50 respectively. In this case the gel adds only the equivalent of 10 ft of additional rock that the oil must flow through to enter the fracture (i.e. 2 ft x 50). In contrast for the water zone the water must flow through the equivalent of 10,000 ft of additional rock to enter the fracture (i.e. 0.2 ft x 50,000). Thus, in this circumstance the gel can substantially reduce water production without significantly affecting oil productivity.

8. 3-D Coning and Cusping³

Gelant or gel treatments have an extremely low probability of success when applied toward cusping or 3D coning problems occurring in unfractured matrix rock. When treating coning problems, a common misconception is that the gelant will enter only the water zones at the bottom of the well. In reality, this situation will occur only if the oil is extremely viscous or the aqueous gelant is injected at an extremely low rate (to exploit gravity during gelant placement). In the majority of field applications to date, the crude oils were not particularly viscous, and gelant injection rates were relatively high. Consequently, one must be concerned about damage that polymer or gel treatments cause to hydrocarbon productive zones. Even if a polymer reduces K_w without affecting K_o , gel treatments have limited utility in treating 3D coning problems. Numerical studies show that gel treatments can provide improvement only if the desired production rate is less than 1.5 to 5 times the pretreatment critical rate.

Gel treatments also are expected to be ineffective when treating cusping. In cusping, like 3D coning, the well is produced so rapidly that the viscous forces overcome gravity forces. For cusping in particular, water from an aquifer follows an inclined zone up to the well. The only practical, method to stop water production from the zone (other than decreasing the production rate) is to plug the zone. Unless extraordinary circumstances exist, hydrocarbon productive zones in the radial flow must be protected during gelant placement.

9. Poor Aerial Sweep

Edge water from an aquifer or injection well during water flooding through a pay zone often leads to poor aerial sweep. Aerial permeability and isotropy typically causes this problem which is particularly severe in sand channel deposits. The solution is to divert injected water away from the pore space which has already been swept by water. This requires a large treatment volume or viscous flood, both of which are generally uneconomic. Infill drilling is often successful in improving recovery in this situation. Lateral drainhole may be used to access unswept oil more economically.

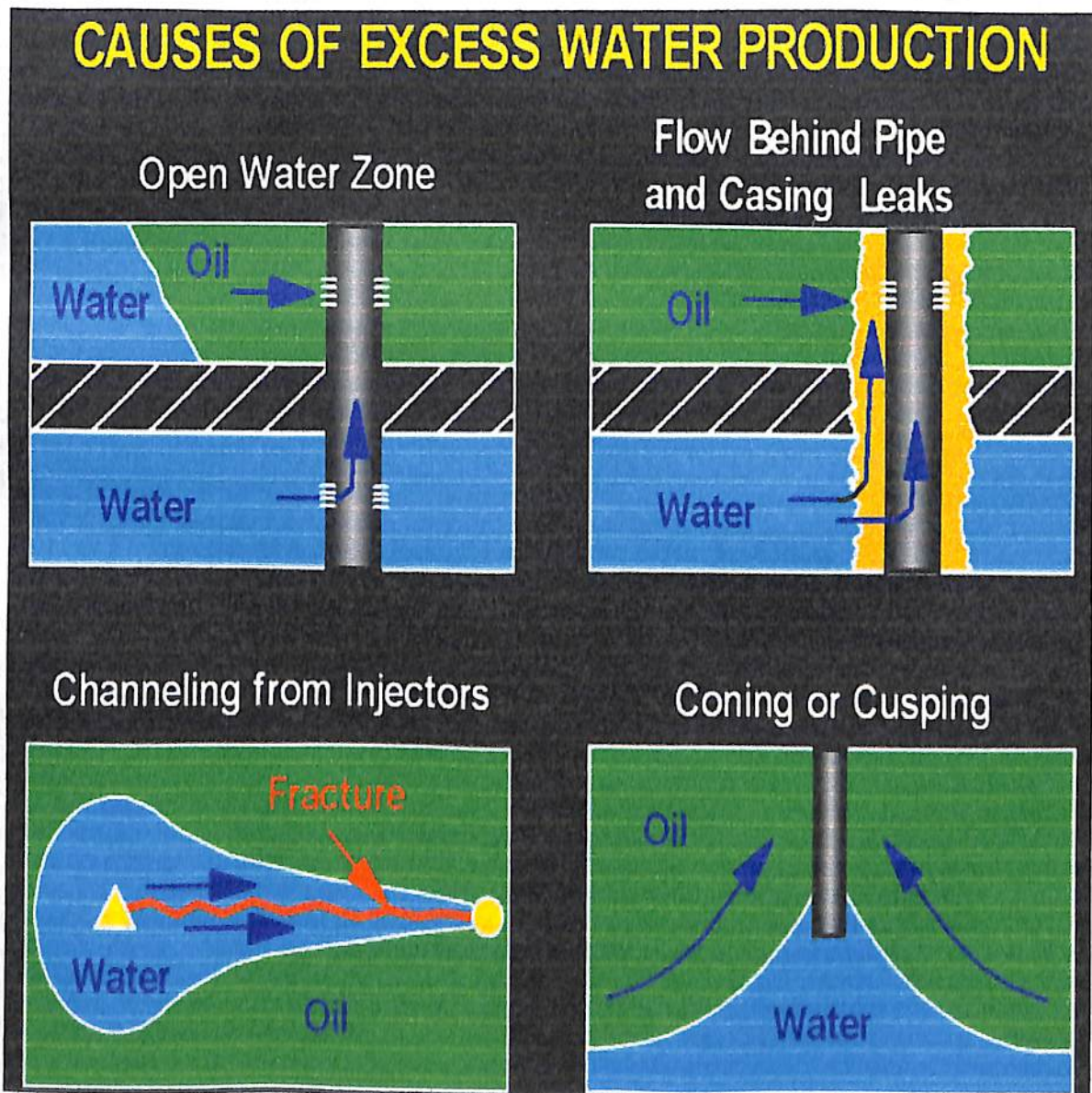
Horizontal wells may extend through different permeability and pressure zones within the same layer causing poor aerial sweep. Water may breakthrough one part of the well simply because of horizontal proximity to the water source. In either case, it may be possible to control water by near wellbore shutoff sufficiently up and downhole from the water zone.

10. Gravity Segregated Layer

In a thick reservoir layer with good vertical permeability, gravity segregation (sometimes called water under run) can result in unwanted water entry into a producing well. The water, either from an aquifer or water flood slumps downward in the permeable formation and sweeps only the lowest part of the reservoir. An unfavorable oil water mobility ratio can make the problem worse. The problem is further increased in formation with sedimentary textures that become finer upward, since viscous effects along with gravity segregation encourages flow at the bottom of the formation. Any treatment in the injection aimed at shut in of the lowest perforation has only a marginal effect in sweeping more oil before gravity segregation again dominates. At the producer there is local coning and gel treatments are likely to provide lasting results. Lateral drainholes may be effective in accessing the unswept oil. Foamed viscous flood fluids may also improve the vertical sweep. In horizontal wells, gravity segregation can occur when the wellbore is placed near the bottom of the pay zone, or when the local critical coning rate is exceeded.

11. Injector - Producer channeling in unfractured reservoirs with crossflow

Gelant and gel treatments are expected to be ineffective for treating injector-producer channels in unfractured reservoirs where fluids can crossflow between zones. Near wellbore blocking agents are ineffective in these applications. Even if blocking agent could be confined only to high permeability channel, water quickly crossflows around relatively small plugs. The only hope for blocking agents in these applications exist if a very large plug (that plugs most of the channel) can be selectively placed only in the high permeability zone. Unfortunately, existing gelants enter and damage all open zones. Penetration and damage caused to the less permeable zones is greater when crossflow can occur than when crossflow can not. Polymer floods provide a more cost effective and reliable solution in this regard.



2.4 Water Problem Diagnosis and Proposed Strategy

In diagnosing problems a primary focus must be to determine whether it is a linear or matrix flow problem. Applying the concept of using information one already has first, such as analyzing injectivity/productivity data, often provides strong clues about the flow environment. If pressure buildup/falloff data of appropriate quality and relevance are available, modern pressure transient analysis techniques are good at identifying linear versus radial flow environments. Production logs, conventional well logs and understanding the geological environment are helpful for determining the flow environment. When tracers are used, transit times are valuable indicators. The strategy for attacking excessive water production problems advocates that (1) the easiest problems should be attacked first and (2) diagnosis of water production problems should begin with information already at hand. To implement this strategy, a prioritization of water production problems is needed. Based on extensive reservoir and completion engineering studies and analyses of many field applications, the various types of water problems were prioritized and categorized from least to most difficult. This prioritization is listed in the following table.

Table - 1

Category A: "Conventional" Treatments Normally Are an Effective Choice	
1.	Casing leaks without flow restrictions (medium to large holes).
2.	Flow behind pipe without flow restrictions (no primary cement).
3.	Unfractured wells (injectors or producers) with effective barriers to crossflow.
Category B: Treatments with Gelants Normally Are an Effective Choice	
1.	Casing leaks with flow restrictions (pinhole leaks).
2.	Flow behind pipe with flow restrictions (narrow channels).
3.	"Two-dimensional coning" through a hydraulic fracture from an aquifer.
4.	Natural fracture system leading to an aquifer.
Category C: Treatments with Preformed Gels Are an Effective Choice	
1.	Faults or fractures crossing a deviated or horizontal well.
2.	Single fracture causing channeling between wells.
3.	Natural fracture system allowing channeling between wells.
Category D: Difficult Problems Where Gel Treatments Should Not Be Used	
1.	Three-dimensional coning.
2.	Cusping.
3.	Channeling through strata (no fractures), with crossflow.

Category A problems are relatively easier to treat. In contrast, category D problems are difficult with no easy, low-cost solutions. The intermediate problems are caused by linear-flow features and can be tackled by optimizing the solution utilizing laboratory work, field experience and theory.

The solution to the problem depends on its kind. Water shutoff treatments are therefore very problem specific. The first step is to identify the problem which is done through well diagnostics.

2.5 Well Diagnostics for Water Control

In the past, water control was thought of as simply a plug and cement operation or a gel treatment in a well. The main reason for the industry's failure to consistently control water has been a lack of understanding of the different problems and the consequent application of inappropriate solutions.

The key to water control is the diagnostics i.e., to identify the specific water problem at hand. Well diagnostics can be used: -

- To screen wells that are suitable candidates for water control
- To determine the water problem so that suitable water control method can be selected.
- To locate the water entry point into the well so that a treatment can be correctly placed.

When a reliable production history is available, it often contains a wealth of information that can help diagnose water problems. Several different analytical techniques using information, such as WOR, production data and logging measurements, have been developed to distinguish between the different sources of unacceptable water which can be described as follows: -

1. Recovery plot

The recovery plot is a semilog plot of WOR against cumulative oil production. The production trend can be extrapolated and if the production is approximately equal to the expected reserves for a well, then the well is producing acceptable water and no water control is needed. But if this value is much less than the expected recoverable reserves, the well is producing unacceptable water and remedial action should be considered if there are sufficient reserves to pay for intervention.

2. Production History Plot

This plot is a log-log plot of oil and water rates against time. Good candidates for water control usually show an increase in water production starting at about the same time.

3. Decline Curve Analysis

This is a semilog plot of oil production rate vs. cumulative oil produced. A straight line curve can be expected for normal depletion. An increased decline may indicate a problem other than water such as severe pressure depletion or damage build up.

2.5.1 Diagnostic Plots – Problem Identification

⁴Among the other sources of water production, water coning, multilayer channeling and near wellbore problems are the most noticeable. Field experience shows successful job design would not be the same for different mechanisms. However, there are no effective methods to discern these differences. In reality the problem could be very complex, and usually is the combination of several mechanisms taking place over a period of time and compounding one with the other. Diagnostic plots can therefore become an effective tool for the selection of water control treatment candidates to enhance treatment success. A set of diagnostic plots have been generated by conducting a series of systematic water control numerical simulation studies using a black oil simulator. These are used as a base for identifying the problem by comparing the graphs obtained from field results with them. Of the many plots available, log-log plots of WOR (rather than water cut) vs. time were found to be more effective in identifying the production trends and problem mechanisms. It was discovered that derivative of WOR vs. time can be used for differentiating whether the excessive water production problem as seen in a well is due to water coning or multilayer channeling.

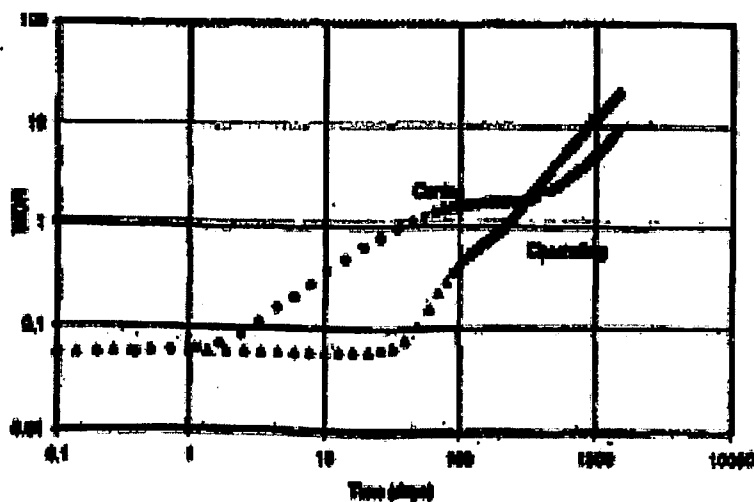


Figure 1- Water Coning and Channeling WOR Comparison

Figure 1 shown above shows a clear distinction between water coning and multilayer channeling development using the same set of PVT and saturation function data, permeability and porosity distribution and having the same initial conditions. Only difference being in flow geometry. For coning, a WOC (water oil contact) was defined and a bottom water influx was simulated by constant pressure water injection at the edge

and only into the bottom water layer. The top 20% of the oil zone was perforated. For channeling the bottom water layer was eliminated. The water injection was modeled with constant pressure water injection into all layers at the edge. All layers were perforated.

Figure 1 show clearly three different periods of WOR development. During the early time period, the WOR curves remain flat showing expected initial production. The value of the initial WOR depends on the initial water saturation and its distribution among all layers as well as the relative permeability functions. The time length of this period depends on the water drive mechanism and its ending is marked by the departure of the WOR from a constant value.

For coning, the departure time is often short depending on various parameters but predominantly on the distance between the WOR and the bottom of the nearest perforation interval, bottom water influx rate, vertical to horizontal permeability ratio, production pressure drawdown or rate and relative permeability functions. Basically, the water coning departure time is the time when the bottom water cone has approached to the bottom of perforation interval.

For channeling, the departure time mainly depends on well spacing, injection rate at the injectors, producer drawdown pressure or rate, initial water saturation and its distribution among layers and relative permeability functions. The departure time of the WOR curve for channeling corresponds to the water breakthrough at a layer in a multilayer formation. This layer may not necessarily be the layer with largest permeability. Initial water saturation and its distribution in the layers becomes a dominant factor if the permeability contrast among the layers is not large.

The second time period shows the WOR increasing with time and this rate of increase differs for different problem mechanism. Figure 1 shows a striking difference between coning and channeling. For coning the rate of WOR increase is very slow and gradually approaches a constant value at the end of this period. During this period the bottom water cone not only grows vertically upward to cover most of the perforation interval but also expands radially. The oil saturation within the cone is gradually decreased to the residual oil saturation level.

For channeling the water production from the breakthrough layer increases very quickly relatively speeding the increase in WOR. The slope of the water channeling WOR depends on the relative permeability functions and initial saturation conditions. At the end of this second period, the WOR increase could actually slow down entering a transition period. This corresponds to the production depletion of the first breakthrough layer. The end of this transition period shows the WOR increase resumes at about the same rate. This corresponds to the water breakthrough at the next highest water conductivity layer. The transition period could be very short depending on the layer permeability contrast. This transition period could become insignificant, when the layer permeability contrast is less than 4. the change of the WOR in the transition period was found to be also affected by the layer crossflow and the capillary pressure function.

In the third period for coning, a pseudo steady cone has been developed and the well mainly produces bottom water. Here, the water cone becomes a high conductivity channel and the WOR increase becomes very fast resembling that of a channeling case. This second departure point marks the beginning of the third period. For channeling, the WOR increase resumes the same rate after going through the transition period. The second highest water conductivity layer is being depleted. All channeling WOR slopes, including the one in the coning situation would be very close because they are mainly controlled by relative permeability functions.

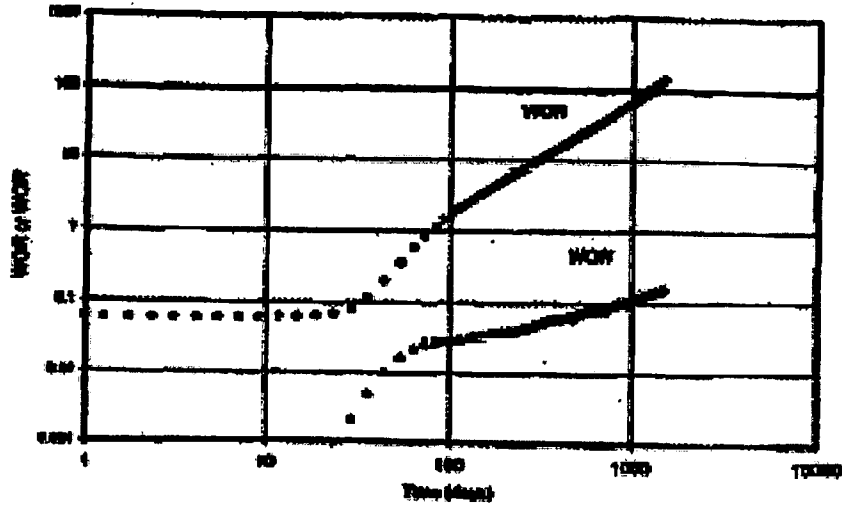


Figure 2- Multilayer Channeling WOR and WOR' Derivatives

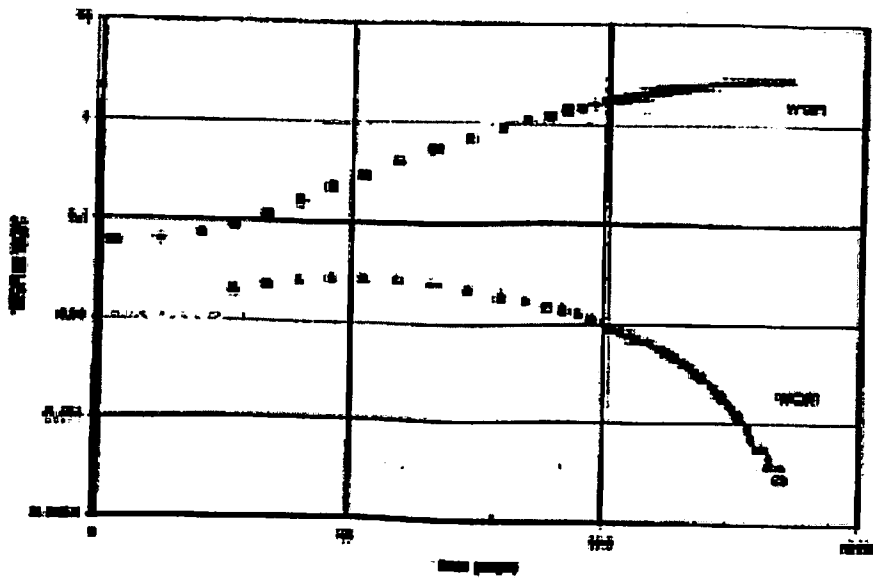


Figure 3- Bottomwater Coning WOR and WOR' Derivatives

Figure 2 and 3 show WOR and WOR' derivatives for channeling and coning respectively. The WOR' being a simple time derivative of WOR shows nearly a constant positive slope for channeling and a changing negative slope for coning. The WOR' trend for channeling behaviour in the third period of water coning situation is shown in fig 4 below. Again the WOR' vs time plot shows a positive slope.

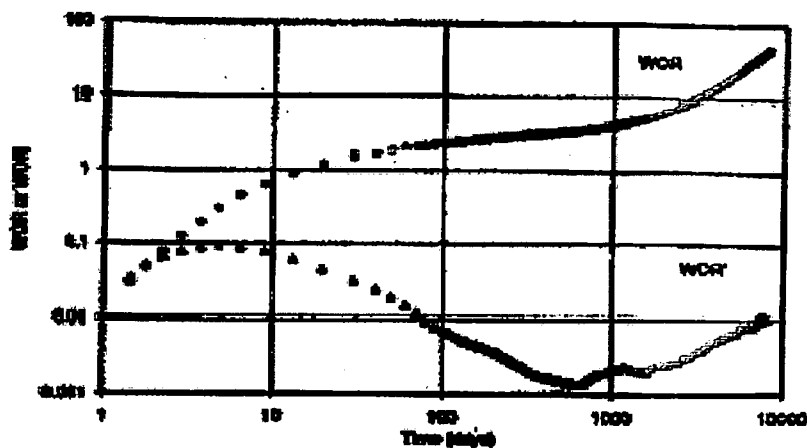


Figure 4- Bottomwater Coning with Late Time Channeling Behavior

The WOR derivative plot becomes very helpful to determine the excessive water production mechanism when limited production data are available. Figure 5 illustrates this advantage. The apparently increasing WOR trend shown in fig 5 could be easily taken as layer channeling. However, the WOR' shows negative slope characteristics of a coning case.

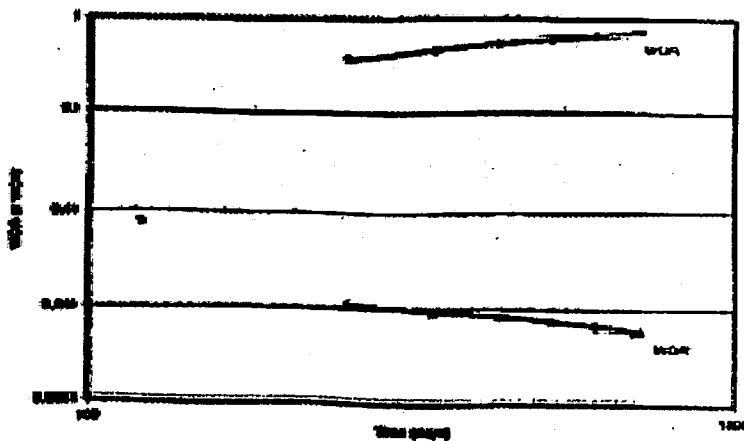


Figure 5- WOR and WOR' from the Coning Case History of the Second SPE Comparative Solution Project

For gas coning in an oil well, the GOR or WGR and their derivatives can be used. Again, slope of the GOR' and WGR' vs time curves indicate different mechanisms – positive slope for channeling and negative slope for coning. An example for the GOR and GOR' plot is shown in fig 6.

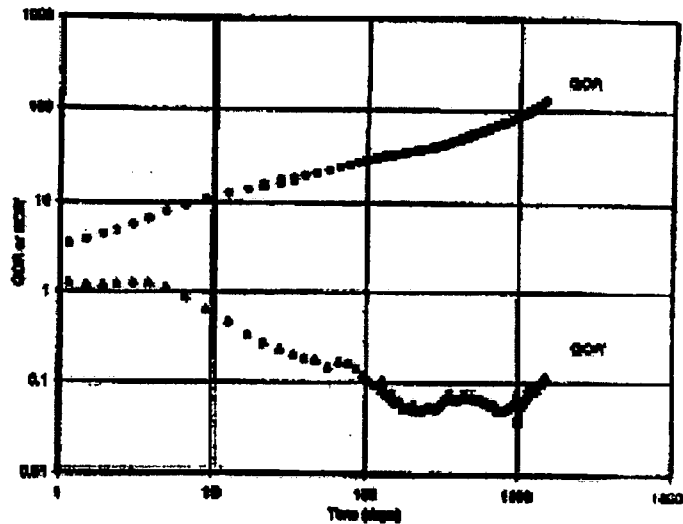


Figure 6- GOR and GOR' Derivatives for Gas Coning in an Oil Well

For a strong bottom water drive, the well spacing becomes a key factor for the occurrence of the second departure point from coning to bottom water channeling.

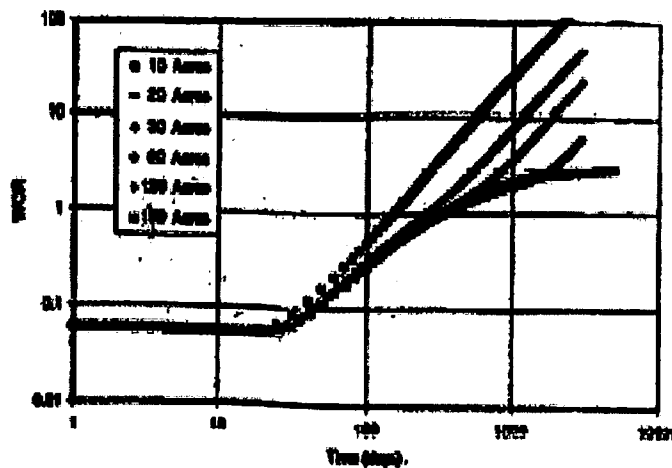


Figure 7- Bottomwater Coning WOR vs Well Spacing

Figure 7 shows a series of simulation plots as a function of well spacing (10 to 150 acres) and at a vertical-horizontal permeability ratio of 0.1. For 10 to 20 acre spacing the second departure point becomes indiscernible. Bottom water appears to be just channeling up

vertically to the perforations which are located at the top of the production formation. Larger the well spacing, further will be the delay of this departure time. This phenomena would also depend on several other factors such as drawdown rate or pressure, water influx rate and the relative permeability functions.

Immediately after the beginning of the water flood, injection water could very rapidly breakthrough very high conductivity channel or thief zone. For instance a 3 ft layer having a 10 darcy permeability among the 100 md adjacent layers could become a water recycling conduit. Fig 8 shows such a situation in the WOR change.

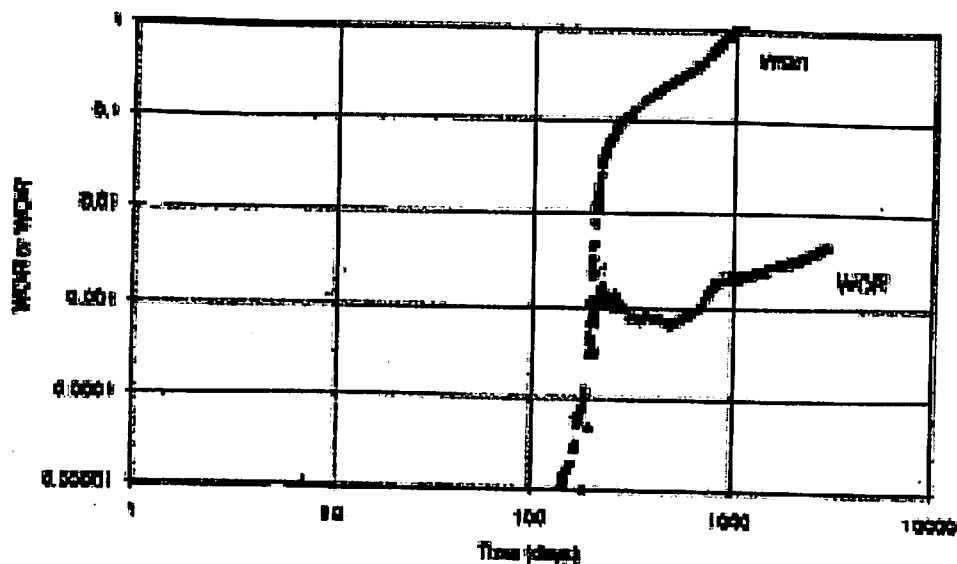


Figure 8- WOR and WOR' Derivatives for Thief Layer Water Recycling

The WOR increases rapidly after the injection water breakthrough at the production well. With a high vertical to horizontal permeability ratio, the water could cone up at the well bore and the water cone could rapidly expand to cover the entire zone. At this time, the water production rate starts to approach the total injection rate. The WOR' curve in fig 8 shows this evolution – a very steep positive slope within a very short time after water breakthrough; followed by a period of a negative slope indicative of cone buildup and a late period of gradual positive slope corresponding to the completion of the water-recycling conductive vertical channel construction.

2.6 Solutions to these Problems

“Water production is the harbinger of problem in an oil well”. It can cause scaling problem in susceptible wells, induce fines migration or sandface failure, increase corrosion of tubulars and kill well by hydrostatic loading. Hence, it is desired to defer the onset of water production for as long as possible.

The methods to attack excess water production can be categorized under two heads-

- Chemical Methods which are easier to use, are more economical but are a bit more risky.
- Mechanical methods require better well completion, are more expensive but are flexible.
- Downhole separation methods.

2.6.1 Chemical Methods

The method to be used depends on the kind of problem and may not work for other problems, therefore, for effective treatment the nature of the problem must be identified correctly.

The chemical methods comprises of -

1. Cement
2. Silicates
3. Visco-elastic anionic surfactants (VAS)
4. Gels and Gelants
5. Resins

Cement System

Cement system comprises of conventional cement squeezes, ultrafine cement, foam cements and matrix treatment which involves poly acrylamide placement followed with a diesel based fine particle cement.

Features of conventional cement squeezes:-

- Used for near wellbore water control or water shut-off.
- Lasts long.
- Densities can be changed as required.
- Often used with other conformance treatments to increase life of the solution. Repair casing leaks and micro-channels in cement.

Ultra-fine Cement (10 micron)

- Repair casing leaks and micro-channels in cement
- Mixed with Ultrafine Pozz, Ultra Fine Silica to add temperature stability and change set time

Hydrocarbon-Based Ultrafine Cements

- Slow reaction when contact is made with water
- Shallow penetration depth
- Used in conjunction with polymer systems to increase their life

Foam Cement

- It is an energized System
- Lightweight
- It has good Compressive Strength
- It is Resilient

Foam Cements Applications

- Repair of natural or induced channels near the wellbore
- Poor primary cement
 1. Natural fractures
 2. Hydraulic fractures
- Ability to control density increases operational flexibility
- Can be used in injector or producer well

Silicate System

- Externally catalyzed sodium silicate reacts with formation chlorides which are used in case of channel behind casing, lost circulation, casing leaks, fracture extension into water zone, injection out of zone and bottom-water shut-off. Externally catalyzed system requires operating temperature from 40 to 550°F, clean equipment, accurate placement details and often need spacer fluid and separate pumps.
- Internally catalyzed sodium silicate is thermally activated. They are generally inorganic gels which have low viscosity during pumping which can provide deep penetration and has low cost too. Internally Catalyzed System (in producing wells) can prevent early water breakthrough, reduce bottom water coning, reduce channeling from injector, reduce water from acid/frac extension into water zone and can also plug well when desired. Internally Catalyzed System (in injection wells) can be used to treat high permeability streaks, reduce channel to producer, reduce injection out of zone, and plug the well when desired. Internally Catalyzed System is not easy to remove and requires clean equipment, requires use of preflush fluid, requires attention to placement details, temperature ranges from 60 to 300°F and requires at least 48 hours of shut in time.

Gels and Gelants

In this project report focus will be on using gels and gelants as an instrument of controlling water production. In the Indian context, where we generally encounter low permeability reservoirs, preference is given to using gels in-situ (gelants) as pumping an already made gel will require enough pressure that may be enough to fracture the formation, thus opening up newer channels for water to break through.

$$P = \frac{i_w}{h}$$

where,

P is the injection pressure

i_w is the injection volume

h is the height of the permeable path

Therefore, the gelling time and thus the depth of penetration is then unpredictable due to uncertainties concerning the shear rates in surface facilities, injection wells and reservoir, as well as petrophysical properties around the wells and the local petrochemical environment.



2.6.2 Mechanical Solutions

The various mechanical techniques to block water from entering the well are as follows:

- Straddle packers,
- Bridge plugs,
- Tubing patches,
- Cement,
- Well bore sand plugs,
- Well abandonment,
- Infill drilling,
- Pattern flow control, and
- Horizontal wells.

In many near wellbore problems, such as casing leaks, flow behind casing, rising bottom water and watered-out layers without crossflow, mechanical or inflatable plugs are often the solution of choice. When the wellbore must be kept open to levels deeper than the point of water entry a through-tubing patch may be the answer. It is particularly well suited to through-tubing water or gas shutoff, injection profile modifications and zonal isolation. The inflatable sleeves are custom-built to match the length of the perforated intervals and can withstand wellbore crossflow pressures. Once set the sleeve becomes that are millable using through-tubing techniques if a subsequent squeeze operation is desired, or it can be re-perforated later to allow reentry to the zones. The disadvantage of the composite liner is a reduction of less than 1" in the wellbore diameter. However, other mechanical path remedies take up even more of the available casing inner diameter. Mechanical approaches, however, may not be effective in solving other more complex types of water production problems. For example, when water is leaking through small-diameter pathways in the casing or the formation, cement is not fluid enough to flow deep into the pathways. For these types of water problems, water shutoff gels and gelants may produce a better result.

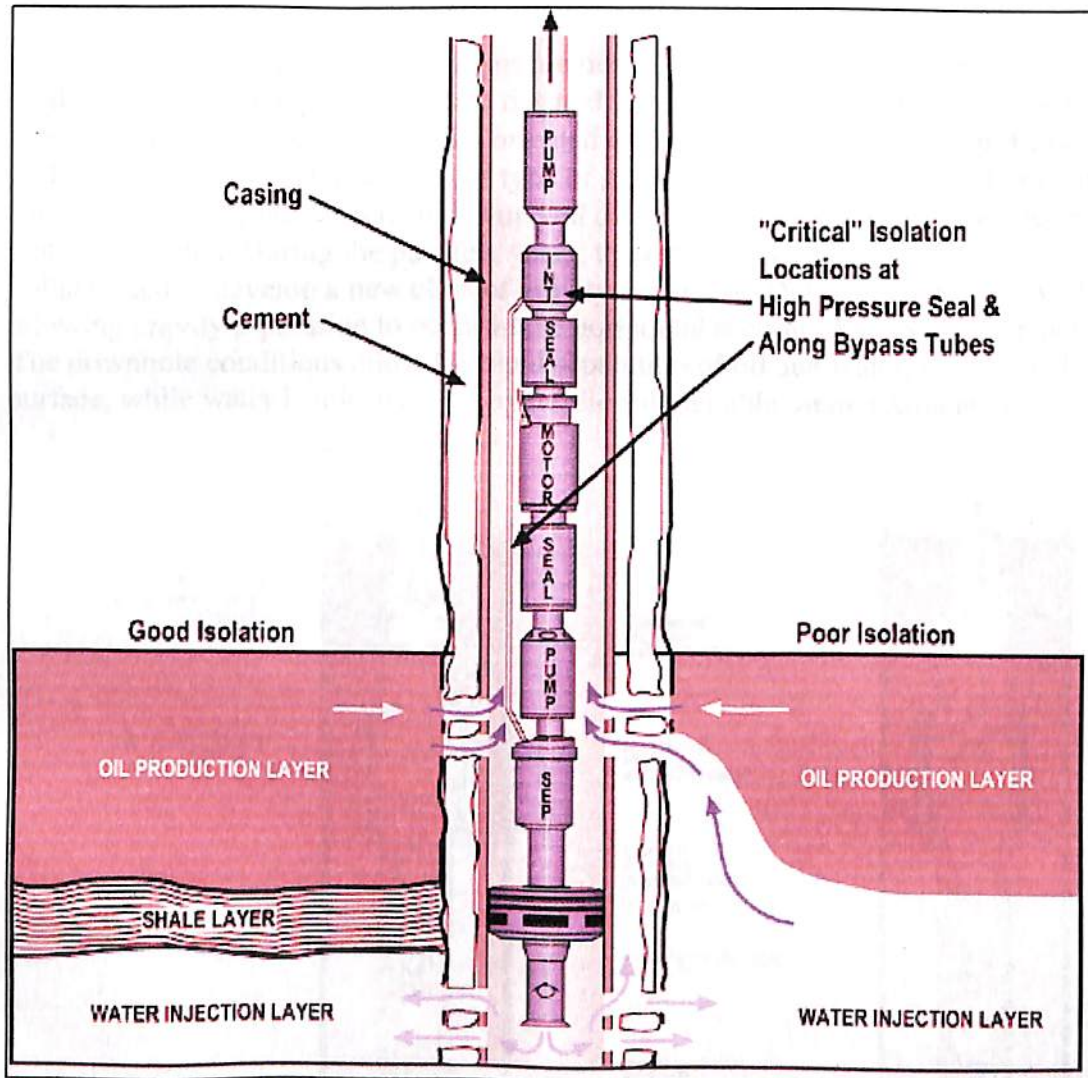
2.6.3 Downhole Treatment

The most desirable way of minimizing produced water involves the use of technologies that prevent the water from entering the well. The fact sheets covering mechanical blocking devices and water shutoff chemicals describe such technologies. However, for most wells, these technologies are not practical or feasible. Operators can still minimize water production through technologies that do not impede produced water from entering the well, but instead, reduce the volume of water brought to the land surface or the platform by separating oil and water remotely.

Lifting water to the surface represents a substantial expense for operators. The process of lifting and managing produced water at the surface exposes vulnerable land surface and surface or ground water resources to potential harm from the produced water. Several technologies have been developed to manage water either in the well bore itself or at a

remote location like the sea floor. This fact sheet describes technologies that separate oil and water (or gas and water) in the well bore, or, by design, produce oil and water through separate pump and tubing systems. Sea floor separation is described in a separate fact sheet.

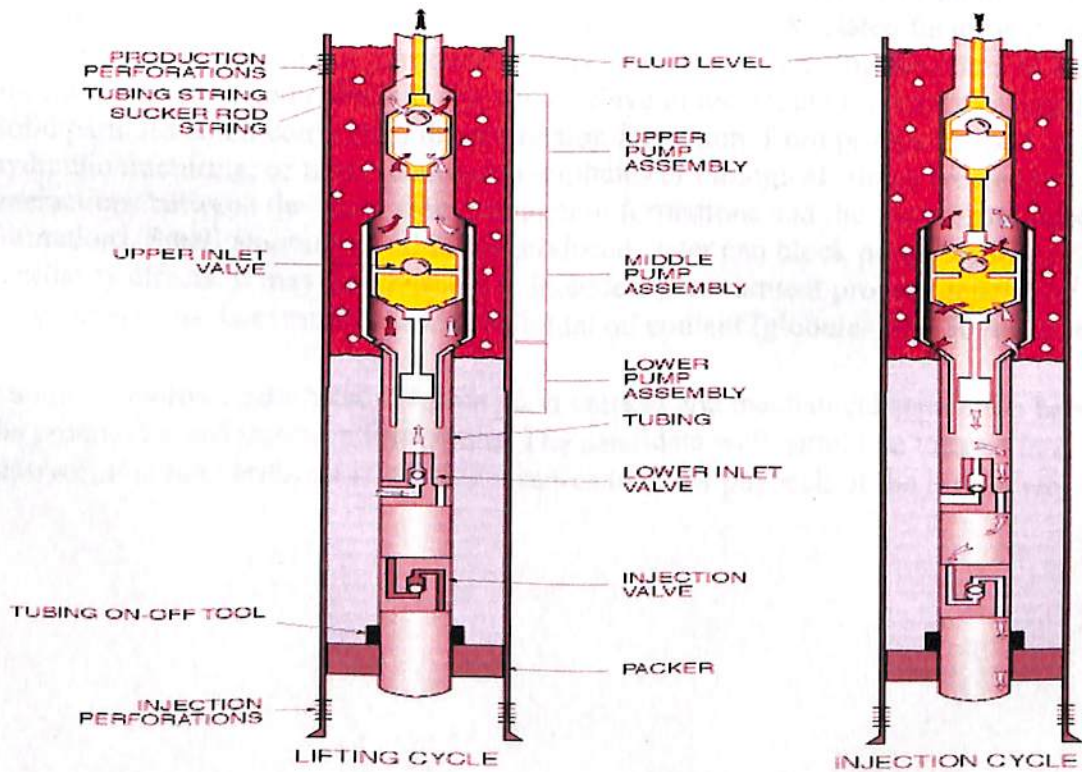
Downhole oil/water separation (DOWS) technology is installed in the bottom of an oil well. It separates oil and water in the well bore. The oil-rich stream is produced to the surface, while the water-rich stream is pumped directly to an injection formation without ever coming to the surface. This can lower costs and improve environmental protection. Two basic methods of separation- hydrocyclones and gravity separation are being used.



The figure shows a downhole oil/water separator. For the purposes of this fact sheet, it illustrates two contrasting geologic and well construction conditions. The left side of the drawing shows good cementing and a sound geologic barrier between the oil and water layers. This configuration will minimize the amount of water entering the well. However, on the right side, water production to the well is greatly increased because of: (a) a poor

cement job between the casing and the well bore, and (b) the lack of a geologic barrier between the oil and water layers. In the figure, both sources of uncontrolled water flow are relatively large in size. These would be good candidates for the deployment of mechanical blocking devices. Hydrocyclones use centrifugal force to separate fluids of different specific gravity. This does not involve any moving parts. A mixture of oil and water enters the hydrocyclone at a high velocity from the side of a conical chamber. The subsequent swirling action causes the heavier water to move to the outside of the chamber and exit through one end, while the lighter oil remains in the interior of the chamber and exits through a second opening. The water fraction containing a low concentration of oil (typically less than 500 mg/L) can then be injected, and the oil fraction along with some water is pumped to the surface.

Gravity separator-type DOWS systems are designed to allow the oil droplets that enter a well bore through the perforations to rise and form a discrete oil layer in the well. Most gravity separator tools are vertically oriented and have two intakes - one in the oil layer and the other in the water layer. This type of gravity separator-type DOWS system uses rod pumps. As the sucker rods move up and down, the oil is lifted to the surface and the water is injected. During the past few years, three North Sea-based companies collaborated to develop a new class of gravity-separation DOWS system that works by allowing gravity separation to occur in the horizontal section of an extended reach well. The downhole conditions allow for rapid separation of oil and water. Oil is lifted to the surface, while water is injected by a hydraulic submersible pump (Almdahl et al. 2000).



Gravity separator-type DOWS system; Source: Argonne report (Veil 2000)

Downhole Gas/Water Separators

Downhole gas/water separation (DGWS) technology is installed in the bottom of a gas well. It separates gas and water in the well bore. A report prepared in 1999 by Radian International for the Gas Research Institute (GRI 1999) offers a very comprehensive discussion of DGWS technology. Much of the information in this section is based on that report. DGWS technologies can be classified into four main categories: bypass tools, modified plunger rod pumps, ESPs, and progressive cavity pumps. There are tradeoffs among the various types, depending on the depth involved and the specific application. Both produced water rates and well depth determine which type of DGWS tool is appropriate for deployment in a specific case.

Bypass tools are installed at the bottom of a rod pump. On the upward pump stroke, water is drawn from the casing-tubing annulus into the pump chamber through a set of valves. On the next downward stroke, these valves close and another set of valves opens, allowing the water to flow into the tubing. Water accumulates in the tubing until it reaches a sufficient hydrostatic head. It then flows by gravity to a disposal formation. The pump provides no pressure for water injection — water flows solely by gravity. Bypass tools are appropriate for water volumes from 25 to 250 bbl/d and a maximum depth in the 6,000- to 8,000-ft range.

Factors for Consideration in Siting DOWS or DGWS Installations

Good injectivity of the receiving formation probably represents the key factor when selecting a site for successful DOWS or DGWS operations. A related factor is that the injection process should not introduce any materials that could clog the pores of the injection formation and reduce its injectivity. Several factors are relevant to clogging. Solid particles could come from the production formation, from proppants used in hydraulic fracturing, or from chemical precipitates or biological slimes created by interactions between the water from production formations and the water from injection formations. Small amounts of oil in the produced water can block pores because of capillarity effects. It may be advisable to include a pretreatment process generating a water stream that is extremely low in colloidal oil content (globules 5 to 50 μm in size).

Another important parameter involves good vertical and mechanical separation between the production and injection formations. The candidate well should be located in a reservoir that has sufficient remaining reserves to allow payback of the investment.

2.6.4 Comparison Between Chemical and Mechanical Systems

- **Chemical systems**
 - Easier to use
 - Usually more economical
 - More risky
- **Mechanical systems**
 - Require better well condition
 - More expensive
 - Less flexible
 - Suitable for minor problems
 - Not specific as it shuts off both oil and water

2.6.5 Which Method to be Applied When?

1. When addressing excess water production problems, the easiest problems should be attacked first, and diagnosis of water production problems should begin with information already at hand. To facilitate implementation of this strategy, problem category list has been shown in the last pages.
2. Conventional methods (e.g., cement, mechanical devices) normally should be applied first to treat the easiest problems—i.e., casing leaks and flow behind pipe where cement can be placed effectively and unfractured wells where flow barriers separate water and hydrocarbon zones.
3. Gelant treatments normally are the best option for casing leaks and flow behind pipe with flow restrictions that prevent effective cement placement.
4. Both gelants and preformed gels have been successfully applied to treat hydraulic or natural fractures that connect to an aquifer.

Treatments with preformed or partially formed gels normally are the best option for faults or fractures crossing a deviated or horizontal well, for a single fracture causing channeling between wells, or for a natural fracture system that allows channeling between wells.

Chapter – 3

Polymer Gel Water Shut Off Treatment

3.1 Introduction

Excessive, unproductive water production is a major problem throughout the world. Polymer-gel water-shut off treatments are one solution. Polymer-gel water-shutoff (WSO) treatments are highly reservoir, well and problem specific. In order to successfully apply a polymer-gel WSO treatment, the underlying problem must be correctly identified and be amenable to polymer-gel WSO treatments. Then an appropriate polymer-gel system must be properly selected, sized and applied. Diagnosing whether flow of the excess water production is linear (e.g. fractures) or radial (matrix rock) is critical since the flow regime greatly influences the required gel composition, volume and placement method.

Polymer solutions and crosslinking agents are mixed together to form a gelant solution. Gelants can flow into porous matrix rock. With time and on chemical crosslinking gelants develop 3-D structures that will not enter into, or flow through, porous rock of normal permeabilities if the gelation occurs too quickly. Gelation time determines how far a gelant can penetrate into a porous rock. Gelation time for most commercial gelants is fairly short even at moderate temperatures. There are several methods to increase gelation time. Higher molecular weight polymers that are incorporated into gel formulations used to treat reservoir high-permeability anomalies, such as fractures, require lower concentrations for 3-D gel formation.

3.2 Hydrosoluble Polymers

Direct treatments of producing well to reduce water production may be classified in two main categories, each one suited to specific conditions. If water and hydrocarbon zones are clearly separated, processes using permanent barriers, which can be selectively placed in the water zone, generally give good results. This impermeable barrier, which aims to stop the flow of all fluids, may be formed by cements, resins, or silicate gels. On the other hand, when oil or gas and water zones are not easily distinguishable, the use of permanent plugs becomes very risky. It is generally preferable to place a selective barrier in the whole pay zone, which blocks water remains permeable to oil or gas. In this case, the systems used are based on hydrosoluble polymers.

After injection of high molecular weight hydrosoluble polymers in the near wellbore region of a reservoir, the polymer adsorbed on the rock has the property to restrain water flow with little effect on oil or gas flow. Moreover, polymer adsorption appears to be almost irreversible, thus making the process efficient for long periods of time. The

polymers most widely used in this process are polyacrylamides having a certain percentage (generally less than 30%) of acrylate functions. These polymers, readily available as powders or emulsions, are relatively cheap. They have a high viscosifying power, especially in soft water, and give high values of permeability reduction to brine when they are absorbed on the reservoir rocks.

Water soluble polymers such as polyacrylamides and polysaccharides have been used as means for improved oil recovery since 1990's. These polymers are crosslinked to form three dimensional structures. For polyacrylamide based gels, the cross-linker can be either metallic or organic.

- **Metallic Crosslinking**

In metallic cross-linking, the carboxylate groups of the polymer chain react with multivalent cations forming ionic bonds. Chromium is the most commonly used metallic cross-linker. A major disadvantage of the chromium-based cross-linkers is their toxicity (carcinogenic nature), especially those that are based on Cr^{+6} . Moreover, the ionic bonds that formed between the polymer and cross linker are unstable at high temperatures. Another concern with inorganic cross-linker is their short gelation times at temperatures greater than $60^{\circ}C$. At temperatures greater than $100^{\circ}C$, polyacrylamide based polymers exhibit hydrolysis and oxidative degradation of the polymer chains.

Also at temperatures greater than $75^{\circ}C$, and in the presence of multivalent cations, over cross-linking occurs, which results in expulsion of water out of the gel structure, known as syneresis.

- **Organic Crosslinking**

Organically cross-linked gels are known to have good stability at elevated temperatures. This is attributed to the covalent bonds that form between the polymer and the organic cross-linker. These gels were reported to be stable at temperatures up to $150^{\circ}C$. In our study we have used the organic crosslinkers as the field being studied is a high temperature field.

The efficiency of the process is directly related to the thickness of the adsorbed layer compared to pore size. In high permeability or fissured reservoirs, the channels through which water flows are an order of magnitude larger than macro molecular size, rendering the process quite inefficient.

3.3 Classification of Gels: -

Gels can be broadly categorized as:-

- Organic gels
- Inorganic gels

Organic gels are preferred in case of high temperature reservoirs due to better thermodynamic stability and better control on gelation time under such extreme conditions (90-150°C).

The following features are to be considered for most field applications of gel in production wells in order to have ideal gel placement:-

- If zones are not isolated during gel placement in production wells, gelants can penetrate significantly into all open zones, not just those with high water saturations.
- In core flood experiments in oil-wet cores, capillary effects could inhibit an aqueous gelant from entering the core. In field applications, however, the pressure drop between injection and production wells usually is so large that capillary effects will not prevent gelant penetration into oil productive zones and this can result in loss of oil productivity.
- Oil productivity loss after treatment in vertically fractured wells is expected to be less than that in unfractured wells.
- In the ideal gel placement, the fracture is plugged far from the wellbore but the fracture remains open near the well. Then water channeling can be reduced while maintaining a high productivity for the well.
- In vertical fractures that cut through multiple zones (in case of horizontal wells, we might want to exploit gravity and density differences to place gel in lower part of the fracture, thereby reducing water influx from the lower zones while leaving the upper part of the fracture open to oil flow.
- If the distance of gelant leak off is great, the near wellbore region could be plugged and the gel treatment could do more harm than good.

Ideal microgels for water shut-off should have the following characteristics:-

- Insensitive to shear and reservoir physico-chemical conditions.
- Size controlled i.e., small enough to ensure an in depth treatment and large enough to reduce significantly water permeability.
- Soft enough to be disproportionate relative permeability modifiers.
- Strongly adsorbing onto pore surface for a long time.
- Non-toxic for the environment.

The four steps of microgel formation are named as

- induction,
- pre gel period,

- size limitation and
- consolidation.

Gels (polymers) reduce water production through relative permeability modification (RPM). RPM offers the option of treatment without zonal isolation which is designed to decrease water production with little or low decrease in oil or gas production (decrease in oil production is a natural consequence of a gel job. But the relative decrease in the amount of water is greater). The simplest RPM used is poly-acryl amide (PAM) or hydrolyzed poly acryl amide (HPAM) or partially hydrolyzed poly acryl amide (PHPA).

3.3.1 Disproportionate Permeability Reduction (DPR)

⁵Disproportionate Permeability Reduction (DPR), refers to the change in water and oil permeabilities after a gel job. Ideally, we desire that the proportion in which permeability to water changes should be greater than the change observed in oil permeability. DPR, in which water permeability is reduced to much greater extent than oil permeability, has been observed in a number of polymer gel system. In our study, the focus was on the effect of relative permeability by flooding the core first with water and crude oil and then flooding with polymer gel, and again flooding with water and crude oil to obtain the changed relative permeability for both water and oil.

When properly designed and executed, these treatments can be successfully applied to a limited range of oilfield excessive-water-production problems. When these treatments are applicable, they may be placed using bullhead injection (not requiring mechanical zone isolation)—a very favorable feature. However, there are a substantial number of limitations and possible pitfalls relating to the successful application of RPM/DPR WSO treatments. First-time application by an inexperienced operator should be considered a somewhat high-risk undertaking. In order to successfully treat unfractured production wells (i.e., radial flow through matrix rock into the well) that are fully drawn down, the oil and water zones should not be in pressure communication and the oil-producing zone(s) must be producing at 100% oil cut (dry oil). When treating unfractured and multizoned production wells that are not fully drawn down, the well's long-term oil-production rate can be increased if the post-treatment drawdown is increased substantially. Treatments that promote short-term (transient) decreased water/oil ratios can, in principle, be applied to many unfractured production wells (that are not totally watered out) in matrix-rock reservoirs. However, these latter treatments must be custom designed and engineered on a well-by-well basis. Furthermore, for most wells, the performance and the economics of such transient WSO treatments are generally marginal. An attractive application of RPM/DPR WSO treatments is the use of robust pore-filling gels in the matrix reservoir rock that is adjacent to a fracture(s) when oil and water is being co-produced into the treated fracture.

Disproportionate permeability reduction occurs when the permeability to brine (formation water) after polymer reduces by larger amount than the permeability to oil.

This is often expressed in terms of residual resistance factor (RRF) also stated as F_{rr} for oil and brine.

The residual resistance factor for oil (F_{rro}) is defined as

$$(F_{rro}) = k_o / k_{og}$$

Similarly, the residual resistance factor for brine (F_{rr}) is defined as

$$(F_{rrw}) = k_w / k_{wg}$$

Where k_{og} and k_{wg} are the permeability to oil and water at endpoint saturation after gel treatment, and k_o and k_w are permeability to oil and water before treatment, at interstitial water saturation and residual oil saturation, respectively.

Thus, disproportionate permeability reduction occurs when

$$(F_{rro}) < (F_{rrw}).$$

3.4 Gelation

Polymer gel system starts as a flowing mixture of two components – polymer and another chemical called a cross-linker. After sometime, each cross-linker molecule, which is tiny as compared to the polymer molecule, starts attaching itself to polymer molecules chemically linking them together. The result is a three dimensional tangle of interconnected polymer molecules that ceases behaving like a fluid and can eventually constitute a rigid, immobile gel.

The polymer may be naturally occurring or may be manufactured synthetically. The cross-linker may be metal ions or metallic complexes that bond ionically to polymer or organic molecule that bond covalently.

Polyacrylamide is a readily available polymer comprising of a carbon-carbon backbone hung with amide groups, possibly tens or thousands of them to provide molecular weight.

However, when mixed with a little alkaline solution, such as sodium hydroxide or sodium chloride or when subjected to elevated temperatures, some of the amide groups convert to carboxilate groups. Each of these carries a negative charge. The proportion of amide group that converts into carboxilate group is called the degree of hydrolysis and typically varies from 0 to 60%. In this form the polymer is called partially hydrolyzed Polyacrylamide (PHPA) and its negatively charged carboxilate group is susceptible to ionic cross-linking.

The carboxylate group has a very high affinity for Hydroxyl group (H_3O^+) and so this gel has got a tendency to move towards the water saturation and get solidify and in turn restrict the permeability of water in the reservoir.

Partially hydrolyzed Polyacrylamide has carboxylic acid and amide groups in the proportion as per the degree to which it is hydrolyzed. Hexamine ($C_6H_{12}N_4$, mol wt: 140.19) at higher temperature and in presence of water forms formaldehyde and Ammonia. Hydroquinone ($C_6H_6O_2$, mol wt: 110.11) on reaction with formaldehyde forms.

This product joins several chains of PHPA and this cross linking results in the formation of gel. During crosslinking the $-COOH$ present in PHPA polymer and $-OH$ in the product formed above combine together resulting in the loss of a water molecule and a link is created between them through oxygen. Similar reaction takes place on the other sides thus several chains of PHPA polymer are crosslinked.

To make the gelant we are not using high concentrations of cross linkers and so there will not be any formation of phenol formaldehyde resin.

The polymers used for the present study are ALCOFLOOD 955 and ALCOFLOOD 935.

3.4.1

(a) ALCOFLOOD 955

Description

ALCOFLOOD 955 is a high molecular weight polyacrylamide copolymer. It has good solubility characteristics over a wide range of salinities. ALCOFLOOD 955 can be cross-linked with both metal [example Cr(III)] and organic cross-linking (hexamine, hydroquinone, formaldehyde etc.) agents to form gels.

Principal Uses

ALCOFLOOD955 is designed for use in profile control treatments to modify reservoir permeability characteristics and improve injection and production profiles.

Examples:

- In-depth blocking of high permeability zones
- Sealing fractures
- Treatment of water coning

Typical Properties

Appearance: White granular powder
Bulk Density: Approx. 0.8 gm/cc

Applications of ALCOFLOOD 955 tend to be reservoir specific.

(b) ALCOFLOOD 935

Description

ALCOFLOOD 935 is a medium molecular weight polyacrylamide copolymer. It also has good stability characteristics over wide range of salinities. It can be crosslinked with both, metal and organic crosslinkers to form gels.

Principal Uses

ALCOFLOOD 935 is designed for use in profile control treatments to modify reservoir permeability characteristics and improve injection and production profiles.

Examples:

- In-depth blocking of high permeability zones
- Sealing fractures
- Channeling Problems

Typical Properties

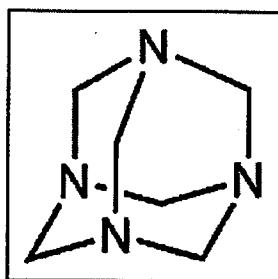
Appearance: White very small granular powder
Bulk Density: Approx. 0.6 gm/cc

Applications of ALCOFLOOD 935 tend to be reservoir specific.

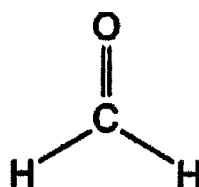
3.4.2 Cross-Linkers

Organic cross linkers are used to link the polymer molecules. Organic cross-linkers used in this project are of Hexamine and Hydroquinone.

The structure of Hexamine is as shown below:

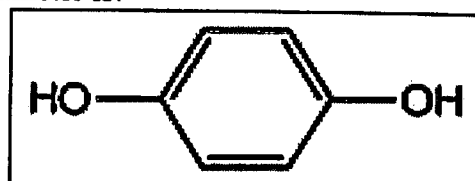


At high temperature this structure breaks into formaldehyde and NH_3 .

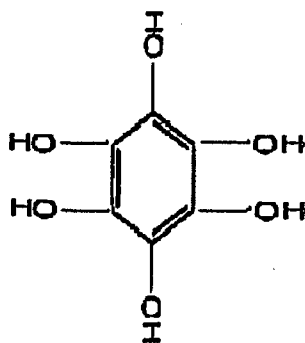


The formaldehyde formed then reacts with Hydroquinone.

Structure of Hydroquinone is:



The reaction between Hexaquinone and formaldehyde give rise to:



This OH^+ group present in this compound reacts with the carboxylic group present in Polyacrylamide polymer, hence forming a large viscous molecule.

3.5 Gel Placement

⁷In small volume applications often applied to treat matrix reservoir rock in the wellbore region, gel formulations exist as fluid gelants during most of the placement process, while with larger volume applications used to treat fracture problems, the formulations exist as partially or fully formed gels during most of the placement process in the reservoir. A minimum pressure gradient must be met before a formed gel will extrude through a fracture. Once the minimum pressure gradient is met, the pressure gradient during gel extension is not sensitive to injection rate. Gels, while propagating through a fracture, dehydrate or lose water to the formation with the amount of dehydration depending on injection rate and time. Gels injected at high rate achieve maximum penetration with minimum dehydration. More concentrated rigid gels can be formed by injecting slower (at slower rates the rate of water loss will be more), decreasing the possibility of gel washout. For example, this might be done at the end of treatment to form more rigid gels in near-wellbore vicinity.



When performing polymer gel WSO treatments in producing wells, the objective is to shut off water without seriously damaging hydrocarbon-producing zones. Thus one wants to maximize blocking agent penetration into water source pathways, while minimizing (or eliminating) penetration into hydrocarbon zones.

Gelants can penetrate into all open zones. An acceptable placement of a gel is much easier to achieve in linear flow (e.g., fractured wells) than in radial flow (matrix reservoir rock). In radial flow there should be a permeability barrier between the oil and water producing zones and the oil producing zone should be isolated from gelant injection. In radial flow without a barrier, heterogeneity alone does not ensure effective placement of water shut off materials.

3.6 Gelation Time and Factors Affecting It

The gelation time is defined as the time needed to reach a certain viscosity.

3.6.1 Effect of the Initial pH Value on the Gelation Time.

In a typical field application, the pH value of the gelling solution may change upon mixing with reservoir fluids and contacting the formation. The presence of acidic gases can also lower the pH somewhat.

There is a rapid increase in the viscosity of the gelling solution at acidic pH conditions but the gel has a very short life and breaks.

At pH greater than 8, there is increase in gelation time and a stable gel is formed. The most important conclusion that can be inferred from these results is that the gelation time depends on the initial pH value of the solution. Low pH values can adversely affect the gelation process.

3.6.2 Effect of Temperature on the Gelation Time

Temperature is a key parameter that determines the gelation time. The gelation time at reservoir temperature is needed to find out how deep the gel can be placed in the formation and how long the shut-in time should be. At room temperature, the viscosity of the gelling solution is observed to increase but no gelation occurs. As the temperature is increased the gelation occurs quickly and the gelation time decreases. This shows the endothermic nature of the gelation reactions.

Thus it is clear that the gelling solution should be pumped within a few hours following mixing on the surface. It will be difficult to pump a gelling solution that has been sitting in the mixing tank for several days.

3.6.3 Effect of polymer and cross-linker concentration on Gelation Time

It is observed that increasing the cross-linker and polymer concentration reduces the gelation time. This is because, as the polymer concentration or the number of cross-linking sites increases, the rate of gel formation increases and hence, the gelation time decreases.

3.6.4 Effects of Mixing Water on the Gelation Time

Gels can be prepared in the field using fresh water, aquifer water or seawater. These waters contain various ions that can impact the gelation process. Therefore it is of interest to measure the gelation time for gels prepared in various waters.

The gelation time for the gel prepared in sea water is nearly double than that for gel prepared in distilled water. This is as increasing the salt content of the mixing water increases the gelation time and delays the cross-linking process.

At high temperatures, the ester groups thermolyze/hydrolyze into carboxylate groups, which carry negative charges. Carboxylate groups can also form upon the hydrolysis of the amide groups of the polymer in alkaline conditions. The repulsive forces between the negative charges will increase the hydrodynamic volume of the polymer chains. As a result, the cross-linking sites become more accessible to the cross-linker molecules. This explains the short gelation time that is achieved by using distilled water.

On the other hand, the concentrations of mono and divalent cations in seawater are high. The cation shields the negative charges available on the carboxylate groups and, as a result, the polymer chains collapse. Consequently, potential cross-linking sites on the polymer chain are not as accessible to the cross-linker molecules. Thus the gelation time will be longer in this case and hence the gel will take a longer period of time to form.

If only saline water is available on the site, then the gelation time can be reduced by either increasing the concentration of the polymer or the cross-linker.

However, adding too much cross-linker may cause over cross-linking and loss of gel volume with time, which is known as gel syneresis. Syneresis is not desirable, especially when the gel is placed in naturally fractured reservoirs. This is because the reduction in gel volume will generate new flow paths, which will reduce the effectiveness of the gel treatment. It is generally observed that gels prepared in saline water are physically weaker than those prepared in distilled water.

3.7 Polymer Gel Water Shut Off Treatments – What it takes to be Successful?

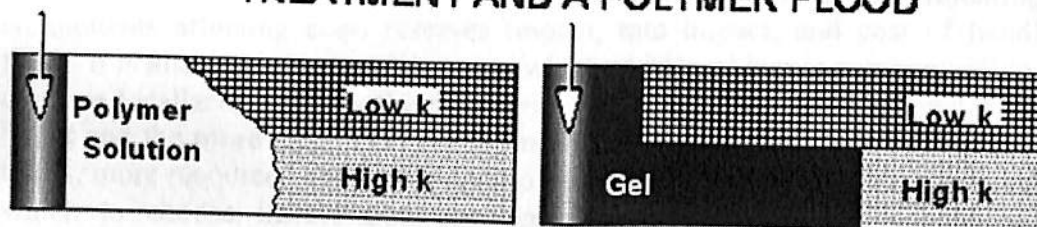
⁶There are many kinds of high permeability anomalies responsible for excess water production. They may be fractures, solution channels, conductive porosity, faults & joints, unconsolidated core sands, high variations in permeability of rocks, channeling behind pipe and casing leaks. Multiple solutions available are mechanical procedures, cement, downhole water separation and chemical procedures (of which polymer gel water shut off treatments are most common). The challenge is to correctly identify or deduce the nature of the excess water production problem at the well to be treated, and then to select an appropriate WSO technology to apply. One must understand that polymer gel water shut off treatments are highly reservoir, well and problem specific.

Polymer solutions and cross-linking agents are mixed together in order to form a gelant solution. Gelants can flow into porous matrix rocks. As time passes, chemical cross-linking takes place and gelants develop 3-D structures that will not enter into or flow through porous rock of normal permeability (less than 10 darcys) if sufficient crosslinking has taken place. Gelation time determines how far a gelant can penetrate a porous rock. These gelation times for most commercial gelants are fairly short even at moderate temperature. There are several methods to increase gelation time. Higher molecular weight polymers incorporated into gel formations used to treat reservoir high permeability streaks require lower concentration for 3-D gel formation.

In small volume applications often applied to treat matrix reservoir rock in the near-wellbore region, gel formulations exist as fluid gelants during most of the placement process, while larger volume application are used to treat fracture problems. The formulations exist as partially- or fully-formed gels during most of the placement process in the reservoir.

To understand how to use gels effectively for water shut-off, one must first recognize the distinction between a conformance treatment (i.e., permeability-reduction or blocking agent) and a polymer flood (mobility-control agent). Conventional gels used in "conformance control" are intended to block or reduce the flow capacity of high-permeability channels without damaging less-permeable hydrocarbon-productive zones. In this situation, the objective is to minimize penetration of gelants or permeability-reducing agents into the less-permeable, oil-productive zones. Any gel or blocking agent that enters the less-permeable zones can hinder (or even shut off) subsequent injected fluids (e.g., water) from entering and displacing oil from those zones. In contrast, polymer floods and similar mobility-control methods are intended to directly displace oil from less-permeable zones (as well as improve mobility ratio and sweep in any given zone.) Consequently, a polymer solution should penetrate as much as possible into the less-permeable zones so that oil can be displaced from these poorly swept zones. For any material that enters the hydrocarbon zones, the engineer must ask, Will this damage the flow capacity of hydrocarbon zone more than that of the water zone?

DISTINCTION BETWEEN A GEL TREATMENT AND A POLYMER FLOOD



● For a polymer flood, polymer penetration into low-k zones should be maximized.

● For a gel treatment, gelant penetration into low-k zones should be minimized.

Fig. —Distinction between a gel treatment and a polymer flood.

Polymers and Gelants Can Flow Through Rock.

Consider how crosslinked polymer gels perform in porous media during conformance-improvement treatments. Early in the gelation process, most gelants (e.g., polymer-crosslinker solutions prior to significant polymer crosslinking) behave like clean fluids that do not contain suspended particulate matter. However, after the first gel aggregates form and grow to the size of pore throats, filtration of the micro-gel aggregates (within the porous rock) can radically increase the resistance to flow.⁶⁻⁸ Gelants can penetrate a

significant distance into porous rock before gelation, but after gelation, gel propagation is extremely slow or non-existent.

Keys to successful downhole intervention to improve injection or production profiles include:

- (1) correct diagnosis of the problem,
- (2) matching a good intervention candidate well with the appropriate technology,
- (3) properly designing the intervention, and
- (4) execution of the design with rigorous quality control.

Polymer gels are an effective choice for certain types of problems, but they should be evaluated in comparison with such established alternatives as mechanical methods (bridge plugs, straddles, sand plugs, etc.) and cement. They should also be compared to the exciting new technologies that exploit downhole separation and disposal and new completions designed to prevent coning.

3.7.1 Important Aspects of Downhole Management of Excess Water and Gas Production.

To determine the true economic target for shutting off excess fluid production, the cost of that fluid production must be determined. This is done by evaluating the three components affecting cost: reserves impact, rate impact, and cost of handling excess fluid. It is also important to determine whether the problem is company-wide, field-wide or more localized. Usually the more widespread the problem, the greater the economic target and the more field locations from which to intervene. With the greater economic target, more resources can be brought to bear on the problem. With more locations from which to choose intervention candidates, there is a greater probability of finding candidates with a high probability of success to begin field implementation of a particular, perhaps unfamiliar, technology.

It is often the case that excess fluid problems are attacked separately by different groups at the various points where they observe a problem: de-bottlenecking a surface facility, recompleting a single offending well, or similar. While these activities can have benefit, there is much more potential benefit to be gained from a planned approach to the whole problem. Just as was the case for understanding the true cost of continuing to produce excess fluid, development of the most effective overall strategy requires a multidisciplinary team effort. For greatest effectiveness the team should have representatives from the engineering disciplines involved with various aspects of fluid production (reservoir, operations, facility/production engineers), plus those who can contribute understanding of reservoir processes that impact excess fluid production (engineers/geologists involved with reservoir description).

3.7.2 Problem Diagnosis and Candidate Selection.

Correct diagnosis of excess fluid production mechanisms is critical to a high probability of successful treatment. To minimize cost of problem diagnosis, it is appropriate to begin investigation of mechanisms by analysis of information that is already available. There is usually more useful data available to help determine mechanisms of fluid influx than is obvious. Often the mechanisms can be determined with a high degree of confidence without carrying out further diagnostic work. Where there is uncertainty of mechanisms, further low-cost diagnostics are often obtainable. Concurrent with this process is determining a clear understanding of the improved probability of success likely from obtaining the additional diagnostics. Thus from uncertainties left after analysis of existing data, appropriate additional diagnostics can be obtained, consistent with the economic target of the problem.

3.7.3 Choice of Appropriate Technology/Treatment Design.

The first and most critical step in choosing the appropriate technology is to correctly identify the problem. One lesson that has been learned with near certainty over the last decade is that there is no "silver bullet" water/gas shutoff technology. That is, there is no one treatment that fixes widely varying problems.

3.7.4 Vendor Evaluation/Selection.

There is a bewildering array of service providers in the downhole fluid management arena. At one end of the spectrum are the major service companies that provide wide-ranging technologies including bridge plugs, cement and various chemical technologies. At the other end are a number of small specialty companies that perhaps provide only one or a very few chemical technologies.

3.7.5 Job Oversight/Quality Assurance.

Polymer gel treatments require a high level of both chemical and engineering quality assurance and control. While a number of gels have robust chemistry, they are still chemical systems and can suffer interference from dirty equipment, incorrect blending or interaction with a number of common oilfield chemicals and contaminants. These issues are straightforward to address in the hands of a specialist. However, with gels it is often the case that a field engineering person is trying to blend and pump a more sophisticated chemical system than is customary or a sophisticated chemist who hasn't learned the limits of field operations is trying to design a blending and pumping procedure. It is rare to have all the required skills under the hard hat of one individual, but that is what is required to maximize success in applying polymer gels in the field.

Water Shut-off in Gas Wells: Proper Placement is the Key to Success¹⁴

The objectives of water-shutoff treatments in gas wells suffering from water influx are to reduce water production and, at the same time, increase gas-production rates and producible gas reserves. Several field treatments, conducted under the umbrella of a research project focused on water abatement in gas wells, have demonstrated that a sequential gel/gas-injection technique in fractured gas reservoirs was successful in reducing water production and increasing gas production. Further efforts focused on improving gel placement in both fractured and matrix reservoirs to improve the treatment efficiency.

Injectivity of the gelant is improved for injection into matrix reservoirs by either reducing the concentration of the high-molecular-weight polymer in the gelant formulation or by using a low-molecular-weight polymer. Gel placement is improved by displacing the gelant away from the near-wellbore region with semistable foam rather than with gas. Such displacement allows for improved gas production after the gel treatment.

Laboratory-scale simulations are used to history match the coreflood result to calibrate the gelation and over displacement options in the simulations. Field-scale simulations demonstrate the merits of the proper gel-placement technique using foam to displace the gelant away from the wellbore in matrix and fractured reservoirs. Optimized gel formulations in combination with the new overdisplacement technique provide a treatment alternative for combating 3D coning situations. This over displacement technique can also minimize the startup problems experienced in fractured gas reservoirs after gel treatments.

Gas production from waterdrive reservoirs often suffers from excessive water production. The influx of water into the gas well requires the gas to lift the water from the bottom of the wellbore to the surface. As the water influx increases, the pressure gradient required to lift the water up the wellbore also increases. This causes a decrease in gas flux from the reservoir into the wellbore; gas production decreases, and eventually the gas well stops flowing. The objective of this water-abatement research project will be to place chemical blocking agents in the gas reservoir to reduce water influx into gas wells, resulting in increased gas-production rates and ultimately increasing the recoverable reserves.

One promising technique to block water propagation in situ is the application of polymer gels. An inherent risk with any gel application is that the flow of any fluid - oil, gas, or water - can be severely impaired. This necessitates the selective placement of the gel in the reservoir so that only the flow of water is impaired. Gas wells are usually perforated only at the top 1 or 2 m of the gas-producing formation. The short producing interval in vertical gas wells does generally not allow for mechanical isolation of the water zone. Therefore, the injection of gelant only into an isolated water zone is not possible unless additional perforations can be shot directly into the water-producing layer. In the latter

case, the gelant could be injected directly into the water-producing zone and a protection fluid (gas or foam) would be injected into the gas-producing layer. The use of a protection fluid ensures that the gelant does not crossflow and inadvertently block the gas-producing zone. However, in most situations, the isolation of the water-producing layer and the gas zone is not possible or economical. Thus, a different gel-placement technique needs to be employed to selectively block the water from flowing into the wellbore. Dovan and Hutchins¹ have advocated a sequential gel/gas-slug injection technique. Here the gelant is bullheaded (without isolation) into the wellbore. Before the gelant is allowed to set, it is overdisplaced from the near-wellbore region with gas. Dovan and Hutchins' laboratory experiments showed that the remaining in-situ gelant, after being overdisplaced with gas, had excellent waterblocking characteristics and did not hinder gas flow. Early field experience of this sequential gel/gas-slug injection technique demonstrated, approximately, a 30% success rate. By improving the selective placement of the gelant in gas wells, the success ratio of the field applications should be increased to the point at which this water-shutoff technique is routinely implemented by gas-producing companies with water-production problems.

The overall research project consisted of three focus areas: laboratory investigation, simulations, and field applications. In the laboratory program, gel evaluation studies were conducted first, followed by coreflood experiments in Berea cores, in carbonate packs, and in fractured cores. Using gas to overdisplace gelant from the core during our linear-coreflood experiments was not an efficient technique because the gas fingered through the core very early on. It was not surprising that the remaining gel blocked both water and gas. Our experiments did not demonstrate the same degree of selective water-over-gas blocking as the Dovan and Hutchins¹ experiments showed. New coreflood experiments were conducted in which the gelant was displaced out of the core with a more efficient displacing agent, such as foam.

The simulation component focused on two areas. The first task was to simulate the laboratory-scale experiments in which gas and foam were used to overdisplace the gelant. The second task was to simulate a field application of the sequential gel/gas process. In the field-scale simulations, a gas well that suffered from bottom-water influx was modeled. The field-scale simulations, carried out on matrix- and fractured-reservoir-scale simulations in the matrix reservoir, compared the outcome of four cases: (i) no treatment, (ii) gel treatment with no overdisplacement, (iii) gel treatment with gas overdisplacement, and (iv) gel treatment with foam overdisplacement.

Successful field applications of the sequential gel/gas-injection process for water control have been conducted in both high-pressure² and low-pressure fractured gas reservoirs. However, the startup period for these wells, immediately after the gel treatment, can be problematic. It may be necessary to install gas lift, or the well may have to be blowdown to remove excess water before the well starts to produce gas on its own. Several field trials have been conducted on coning situations in sandstone reservoirs. The success of our gel treatments in matrix formations has been very limited because of various factors.

3.8 Alternative Gel Systems and Crosslinkers

3.8.1 pH Triggered Gels for Water Shut-off and Conformance Control

As oil fields mature, the volumes of produced water requiring disposal have increased significantly. With numerous older and mature oil fields, the growing problem of water production and stricter environmental regulation of water disposal are forcing oil producers to find ways to eliminate water coning and conformance control problems. Approximately 20 billion barrels of water are reinjected in the US every year. Any technology that minimizes the amount of water or gas produced in conjunction with the produced oil would have a significant impact on the energy consumption and on the cost oil production domestically.

There are many factors, such as the presence of thief zones or high permeability zones, fractures and water coning which lead to an increase in water production. In an attempt to block out the undesired water production and increase the volumetric sweep efficiency of on-going water floods, the industry has used crosslinked polymer gels. The process involves strategically injecting a gelling fluid into water coning well or into a high permeability watered out zone, restricting flow in that zone and redirecting water flow into the lower permeability unswept oil zones. Thus water shut off and conformance-control treatments can be used to generate relatively large volumes of incremental oil production with low costs and selectively, targeted small volume treatments, which extends the economic lives of marginal and mature wells.

However, several, significant problems have been encountered in the application of cross-linked gel systems: Difficulty in controlling gelation kinetics, placement of the gel deep into the formation, retention and adsorption of the cross-linking agents on the rock surface, long term stability of polymers, especially at high temperatures, environmental undesirability of using cross-linking agents such as chromium, and gelation is irreversible and misplacement of these agents into undesirable zones can be disastrous to the productivity of the well.

Hence a new method proposes the novel use of pH-triggered gels that can be placed deep into the water bearing parts of the reservoir. The proposed gel technology is cheaper, more environmentally friendly, easily reversible and readily cleans up. The proposed polymer gel does not involve any cross linking polymer for inducing gelation and hence has significant advantages over the polymer gels being used in the industry at present. The gelation is not kinetically controlled but rather depends on the pH of the polymer solution. An increase in pH leads to gel formation while a reduction in pH reverses the gel into a low viscosity polymer solution. The overall objectives of the pH triggered gel system are to improve the effectiveness of gel treatments in production wells for water shut-off and conformance control for water floods, through the application of pH-triggered gels

3.8.2 Silica Gel Formulation in Tight Matrix Reservoir

A delayed gelling system useful in conformance control in the production of petroleum from subterranean formations, especially low permeability formations, is disclosed. The gelling system comprises a basic silica sol, an activator comprising a hydroxyl donor, and an optional syneresis inhibitor. In the disclosed method of using the gelling system, the gelling system may be pumped into formations with excessive water and/or gas production and thermally activated in the formation at downhole conditions to form a hard gel to reduce water and/or gas production.

The delayed gelling system of this invention forms a solid gel from a basic colloidal silica sol where silica particles are present in the sol at from 15 to 70 percent by weight which is activated by a thermally releasable hydroxyl donor that further increases the pH. The hydroxyl donor is present in amounts of from 0.1 to 10 percent by weight.

In one embodiment the invention provides a delayed gelling system including a basic colloidal silica sol and an activator comprising a thermally releasable hydroxyl donor. The delayed gelling system in one embodiment has a pH between 9 and 12 and in another embodiment a pH between 9 and 10.

In one embodiment, the silica comprises negative ionic surface modification, and in another the silica is surface modified with aluminate ions.

In an embodiment, the delayed gelling system also includes a syneresis inhibitor, such as, for example, a sulfate. In some embodiments, the syneresis inhibitor is present at from 0.05 to 0.1 percent by weight.

In one embodiment, the delayed gelling system may include an ionic strength modifier such as a salt present, for example, at a concentration of from 0.1 to 10 percent by weight, or from 0.5 to 5 percent by weight.

The present invention also provides a method of inhibiting permeability of a portion of a subterranean formation. The method can include the steps of:

- (a) preparing the stable aqueous colloidal dispersion described above;
- (b) injecting the colloidal dispersion into a portion of a subterranean formation having a temperature above the thermal activation temperature of the hydroxyl donor to elevate the pH;
- (c) setting the colloidal dispersion into a hard gel in place in the formation to inhibit water permeability of the portion of the formation; and
- (d) producing fluid from a remaining portion of the formation.

The gelling system of the present invention comprises a delayed gel formed from a basic aqueous solution of colloidal particles, with gelling control by hydroxyl donors and an optional syneresis inhibitor. The crosslinking reactions of this new system are controllable and robust. The pre-gel fluid before it sets has a low viscosity for pumping and placement. One use of the fluid is pumping into a formation with a low permeability, such as less than 100 millidarcies (mD), less than 50 mD, less than 10 mD, less than 1 mD, for example from 1 to 100 mD or from 0.001 to 1 mD. As used herein, a "tight formation" is one with permeability less than 100 mD.

Colloidal suspensions are typically dispersions of discrete very small particles, spherical or elongated in shape, charged so that the repulsion between the same charged particles stabilizes the dispersion. Disturbance of the charge balance due for instance by removing the water, changing the pH or adding salt or water-miscible organic solvent, causes the colloidal particles to aggregate, resulting in the formation of a gel.

The dispersion is prepackaged as a liquid, transparent in the case of relatively low concentration of particles, becoming opalescent or milky at higher concentration. In any case, the dispersion may be handled as a liquid, which greatly simplifies the preparation and use of fluids.

Commercial solutions of colloidal particles typically include silica (also known as silica sol) and/or oxides of aluminum, antimony, tin, cerium, yttrium and zirconium. The particles are mostly spherical with particles sizes usually ranging from about 4 nm to about 250 nm, but elongated particles, with a length up to 300 nm are also available and believed to be acceptable for the invention. The particles may have a negative or positive charge. Negatively charged particles may be surface modified with aluminate ions, for example. Aqueous solutions of colloidal silica particles, with particle sizes ranging between about 4 nanometers and about 100 nanometers have been found to have an excellent injectivity in tight formations with permeabilities as low as 1 mD or less to 50 mD. Preferred colloidal particles have a size between 4 and 22 nanometers. This unique property allows a treatment of the formation to a desired depth.

The gel formation is triggered by a pH modifier with or without an ionic-strength modifier. According to one embodiment of the present invention, said pH modifier is a base. Colloidal silica dispersions used for conformance control applications have mostly a pH between 9 to 12, preferably 9 to 10. By adding a hydroxyl donor, the pH of the colloidal dispersion can be further increased to accelerate gel formation. In this way, the charges on the surface of the silica particles are decreased and the particles can come into contact and form siloxane bonds. It has been discovered that the tendency of basic colloidal silica to gel is increased at a pH above about 10. The gelation time can be adjusted with the pH of the solution and/or the temperature for a given silica particle size and concentration.

The concentration of the pH modifier and of the ionic strength modifier is comprised between 0.1 and 5 wt % and preferentially comprised between 0.1 and 1.5 wt %.

The volume of conformance control fluids to inject is preferably equal to at least the volume of the pores of the portion of the formation to be plugged. Said volume is usually no more than 10 times the volume of the pores in the area to be plugged. In general, the area to be plugged has a depth of between about 0.5 and about 10 m, or between about 2 and about 7 m, typically about 4 m, although it is not unheard of to plug extended distances, and theoretically as far as the control fluid can reach for extended pumping periods up to the set time of the first-injected fluid.

The syneresis inhibitor which is present in the pre-gel solution in one embodiment may be a polyvalent anion such as, for example, tartrate, citrate, sulfate, oxalate, succinate, or the like. The syneresis inhibitor generally delays or prevents separation of water from the gel over an extended period of time at formation conditions. In a general embodiment, the syneresis inhibitor, when present, comprises from 0.05 to 0.5 weight percent of the pre-gel solution. In various embodiments, the syneresis inhibitor has a lower concentration limit in the pre-gel solution of at least 0.01, 0.05, 0.1, 0.2, 0.25, 0.3, or 0.4, weight percent, an upper concentration limit of not more than 2, 1.5, 1.0, 0.8, 0.5, 0.3, or 0.1 weight percent, or a concentration range from any lower limit to any higher upper limit, e.g. from 0.05 to 0.1 weight percent.

The pre-gel solution may also contain various other additives used in water shutoff gel systems such as surfactants, thermal stabilizers, antifoaming agents, pH buffers, scale inhibitors, water control agents and cleanup additives, and the like.

The pre-gel solution is prepared by blending or mixing the silica sol, pH modifier, syneresis inhibitor, dilution water and any other additives together in any order using conventional blending and mixing equipment and methods. The pH of the blend components is maintained so as to avoid precipitation or premature gel formation, especially avoiding localized pH or salinity increases when high pH, neutral pH or salt components are added to the silica sol. The blending and storage temperature is also maintained below the activation temperature to ensure that the gel is not formed prematurely before the solution is placed in the appropriate location where the gel is desired.

The pre-gel solution is generally prepared shortly before it is used, then injected, and then heated in the reservoir to a sufficient temperature to further elevate the pH so that gelation is activated. In water- or gas-shutoff applications, also known as conformance control, the pre-gel is prepared to have the rheology required for injection into the reservoir, taking into account the temperature, permeability and fluid content of the formation, preferably a viscosity less than 5 cP at the reservoir injection conditions. The pre-gel is also prepared to give an appropriate set time upon injection into the formation, and the desired gel characteristics. For example, the set time will normally be longer than the time it takes to finish injecting the amount of pre-gel solution for the particular application. The injection of the pre-gel solution can be preceded by or followed by injection of a spacer fluid to avoid mixing with other fluids that might prematurely gel the solution. If desired, the injection of the pre-gel solution can be followed by injection of an accelerating fluid to speed up gel formation or a temporary gelling fluid to form a

cap to guard against undesired pre-gel migration before it gels. The injection of the pre-gel is otherwise similar to familiar shutoff methods known in the art.

3.8.3 Cr(III)-Carboxylate/ Acrylamide Polymer Gels

CC/AP gels for conformance control and fluid shut-off applications are aqueous -based gels in which acryl amide polymers are chemically crosslinked together with a Cr(III)-carboxylate-complex crosslinking agent in a single fluid. The chromium-triacetate chemical complex is often the preferred Cr(III)-carboxylate crosslinking agent used in conjunction with this gel technology. At or near room temperature, gelation onset times of minutes to months are possible. However, economic and other constraints often favor CC/AP gel formulations that have a narrower window of gelation onset times (hours to several days). For any given CC/AP formulation, the gelation rate increases with increasing temperature.

There are presently two major conformance treatment formulations versions of CC/AP gel technology that are in wide use. The first version involves the use of high (>4,000,000) molecular weight polymers incorporated into the gels at relatively low polymer concentrations (0.3 to 2.0%). This version is usually employed to selectively treat fractures or other multidarcy high permeability anomalies within petroleum reservoirs. The second version involves the use of relatively low (200,000 to 2,000,000) molecular weight polymers and relatively high (3.5 to 7.0%) polymer concentrations in the gel formulations. This version of gel technology is used in total fluid shut-off treatments that are usually applied in the near wellbore (often 15 ft radial penetration) region of the unfractured matrix rock. Having in place and executing a strong quality control and assurance program are essential for maintaining a high success rate when applying the CC/AP, or any other conformance treatment technology.

3.8 Summary

3.8.1 High Temperature Applications of Polymer Gels

High temperature gels require high chemical (polymer and/or crosslinker) loadings and slightly higher chemical loadings when employing carboxylate gelation-rate retarding agents. For higher temperatures there is a variety of gelation delay mechanisms that can be employed, individually or in combination which can be synergistic:-

- Use of various organic crosslinking agents
- Use of low hydrolysis polyacrylamide
- Chemical retarder additive package
- Pretreatment cooling water injection

3.8.2 Problems where polymer gel treatments are an attractive option include:

- Matrix strata conformance problems without crossflow
- Fracture problems, intermediate intensity network with directional characteristics. Polymer gel treatments are often not attractive when applied to a highly intense fractured network.
- Hydraulic fractures inadvertently extending down into an aquifer.
- Coning through fractures, but not matrix rock coning.
- Behind pipe channeling, micro flow channels

3.8.3 Characteristics of Candidate Wells Selected for Water Shutoff

- High WOR
- Excessive unproductive water production
- Substantial movable oil saturation in the well pattern being treated
- Unexpectedly low oil recovery
- Early water or gas breakthrough
- High fluid level in wellbore

3.8.4 Prerequisites of successful water shut off treatment:

- Treatment fluid functions as intended downhole.
- Problem is correctly identified
- Proper treatment fluid system is selected
- Treatment is properly designed and sized
- Treatment fluid is properly applied

3.8.5 Additional areas where technological advances are needed:

- More cost effective and operator friendly techniques for identifying conformance and more excessive water problems
- Better and more complete gel placement in fractures
- More science in selection of over-displacement fluid and sizing volume
- Eco-friendly gel technologies
- Better and more effective high temperature gel technologies

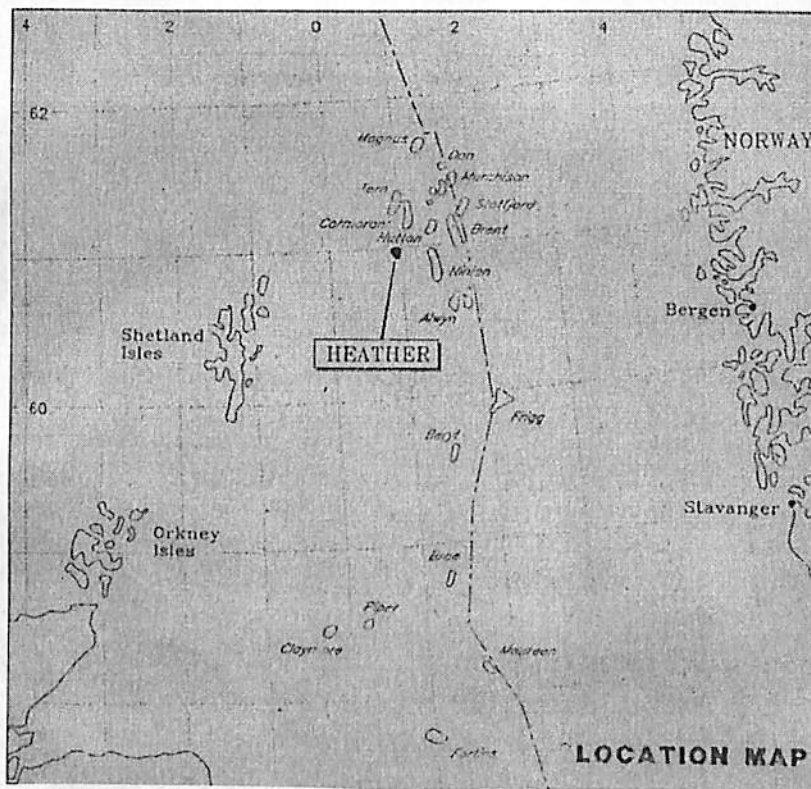
A case history of water shut off in the North Sea: Testing a new polymer gel system in the Heather field, UKCS Block 2/5, SPE paper 30426 is enumerated in the next chapter.

Chapter – 4

Case History

Water shut-off in the North Sea: Testing a new polymer Gel System in the Heather Field, UKCS Block 2/5

The Heather Field is located in the Northern sector of the U.K. North Sea and produces from the lower (Broom, Rannoch, and Etive) and upper (Ness and Tarbert) layers of the Brent sandstone lying at depths between 9,500 and 11,800 ft TVD-SS.



As is the case with several other Brent Group fields, the most productive zone is the foreshore and upper shore face facies of the upper Ness and Tarbert formations. Strong permeability contrasts between these layers and the lower permeability Broom and Rannoch sands combined with various levels of communication between producers and water injectors have results in water cuts near 100% from the high permeability layers. The less permeability layers are typically producing at lower water cuts, and may not be producing at all because of the effects of variable layer pressures and a higher flowing bottom hole pressure.

Historically, conventional water shut-off treatments have been performed by cement squeezing the offending perforations. Although this technology is widely practiced, the success rate has often been lower than desired. Frequently, an initial successful squeeze will break down within months of the treatment, necessitating additional cement squeezes to maintain shut-off.

Polymer gel systems have two main advantages over cement. First, the polymer is injected as a solution that can penetrate the reservoir rock and reduce permeability in the near wellbore, sealing cracks and existing micro annuli within the original cement sheath.

In contrast cement is more acid resistant, has more strength than polymer gel, and will resist higher pressure gradients. However, the deeper penetration of the gel and larger emplaced volumes tend to counteract these effects because the gel penetrates several feet into the formation. Moreover, within porous media, the gel exhibits higher strength than does the bulk gel itself. Degradations from acid treatments will be limited because the acid will not penetrate to the full depth of the gel. The nearly infinite viscosity of the gel resists the convective transport of the acid through the gel and restricts the degradation reaction to the exterior gel surfaces.

Several other considerations also favor the use of polymer gels. Gel left in the well can be cleaned out by jetting by means of coiled tubing with either a mild acid solution or water. Cement left in the hole is more difficult to remove, requiring a contamination and circulating out procedure or milling and under reaming. If the complete perforated interval is cemented, re-perforating would also be required. Polymer gel treatments are typically less expensive than cement squeezes because of reduced crew and rig time. Both techniques require setting time to allow the plugging agent to develop full strength. High injection pressures used to help dehydrate the cement during a squeeze are not required for the polymer gel because gelation is dictated by chemical reactions, which are only dependent on reactant concentrations, brine composition, and reservoir temperature. The recent development of a unique gel system compatible with sea water and stable at reservoir temperatures encountered in the North Sea was the key driving force for additional consideration of polymer gels for water shut-off.

The high-temperature polymer gel system was developed by Unocal in 1992 for use in various high temperature fields. Unlike traditional gel systems, which have temperature limitations near 200° F, the high temperature polymer gel system has proven stable in sea water at temperatures up to 350° F. It is easily mixed and is a forgiving system because the gel properties are not influenced by small errors in chemical concentration. The use of organic crosslinkers allows for longer gelation times and therefore does not require that the treatment layer be precooled by cold water injection before gel placement.

The chemicals that comprise the new polymer gel system are more environment friendly than other polymer systems that employ carcinogenic ingredients like dichromate and formaldehyde as crosslinking agents. Because of the temperature of gelation, the gelant mixture can be mixed and stored at ambient temperatures for weeks before use. With this unique feature, expected pump shutdowns will not result in tanks filled with cured gel.

Solutions can also be premixed in a controlled environment and transported to the well site for pumping.

4.1 Polymer Gel Screening Tests

Gel screening was performed in the laboratory to determine the stability and gelation times using polyacrylamides manufactured by two different suppliers. The medium molecular weight polymers had approximately 10% anionic charge. The screening tests conducted at reservoir temperature (230° F) showed that the performance of the two polymers was nearly identical.

Gel-strength measurements in open tubes were performed to compare the high temperature polymer gel system with a chromium crosslinked gel system. In these tests, increasing pressures were applied across a 1 ft long tube filled with the gelant, which has been cured at 250° F. the pressure required to initiate water flow was recorded. Both the high temperature polymer gel and the chromium crosslinked gel showed excellent gel strength. An applied pressure of 400 psi across the tube was required to initiate flow in both cases.

Similar gel strengths measurements were made in 1 ft long tubes packed with 12/20 frac sand. Permeabilities ranged from 36,000 to more than 100,000 md before gel placement. The results shown in table below demonstrate that the organically crosslinked gel can withstand pressure gradients up to 1,000 psi/ft. Permeabilities following the gel treatment were less than 300 md, with some Permeabilities as low as 0.3 md. Note the formulations with lower concentrations will not exhibit this degree of gel strength but will nonetheless substantially reduce fluid permeability.

Table - 2

Gel strengths measurements in 1-ft-long tubes packed with 12/20 Frac Sand		
Gel cured at 250° F with listed crosslinker Polymer/Chromium Acetate Ratio = 20 1% Medium Molecular Weight Polymer		
Pressure required to initiate flow		
Result	Organic	Chromium
Average	800 psi	225 psi
Range	500 to 1000 psi	50 to 400 psi

4.2 Treatment Procedure

Well H-43 penetrates the Brent group at an inclination of 52° and is completed with a 7-in. liner. It is observed that the bottom perforation of the upper Brent being 44 ft above the top perforation of the lower Brent, a reasonable distance for depth control purposes. The wireline entry guide (WEG) is located 108 ft above the top perforation.

The well intervention procedure included a number of coiled tubing runs with various bottom hole assemblies. An under reaming assembly was used for wellbore cleanout of scale through the upper and lower Brent zones. After cleaning the hole, several protective calcium carbonate pills were placed at the bottom of the wellbore across the lower Brent zone. Next, polymer gelant was injected into the upper Brent and the well was shut in to allow the gelation reaction to occur. Finally, the calcium carbonate pill was dissolved with acid and the hole was cleaned before initiating production.

4.2.1 Scale Removal

The perforated interval was under-reamed using 1^{1/2}-in. coiled tubing, a 2.125-in. positive displacement motor, and a six inch under reamer. The well was placed on production during under-reaming operations to minimize formation invasion of work over fluids. Filtered, inhibited sea water was used as a circulating fluid and viscous fluids composed of a mixed metal hydroxide fluid system were circulated to aid solids removal. Depth control was achieved using previously measured wireline holdup depth and WEG location from prior production logging operations.

4.2.2 Protecting the lower Brent Perforations

The lower Brent perforations were isolated with a mixture of 300 to 500 micron calcium carbonate suspended in HEC polymer solution. The mixture was pumped in five barrel stages and tagged with the coiled tubing after the predicted setting time had elapsed. Depth control was maintained by incorporating a tubing end locator in the coiled tubing bottomhole assembly.

This operation was the most difficult and time consuming portion of the treatment. The top of the settled calcium carbonate pill proved difficult to tag with coiled tubing. A 500 lbm set down weight of the coiled tubing yielded inconsistent tag depths and appeared to indicate only the presence of a bridge. The program was completed based on a 1,500 lbm set down weight, which was thought to represent a solid pack. Complications arose from the apparent settling of the calcium carbonate on the low side of the wellbore, which was subsequently dragged up the well by the bottomhole assembly when attempting to tag the top of the pill.

After the planned tag was achieved, a reduced injectivity was measured in the upper Brent perforations. At this time, a 7.5% HCL acid wash was performed on the upper

Brent to remove any residual calcium carbonate. In addition, a gel cap was placed on top of the calcium carbonate pill to ensure zonal isolation and prevent further migration of the calcium carbonate.

4.2.3 Sealing the upper Brent Perforations

The polymer gel treatment was designed to provide a 20 ft radius of polymer gel throughout the 15 ft of net pay of the upper Brent. The gel was pumped with increasing polymer and crosslinker concentrations and ended with a high concentration and ended with a high concentration, high gel strength stage.

The treatment was designed to pump through coiled tubing at 1 bbl/min. the pumping operation was constrained by maximum allowable coiled tubing pumping pressure of 7,500 psi and a maximum wellhead pressure of 4,300 psi. The friction pressures were calculated using a non Newtonian, power law equation, which accounted for pipe roughness. Temperature predictions proved to be the most difficult step in the procedure because temperature was changing throughout the treatment period. Over the anticipated temperature range for the injection string, the range of pressure drops for an injection rate of 1 bbl/min were estimated and shown in the table below.

Table - 3

FRICTIONAL PRESSURE DROPS FOR FLUIDS FLOWING AT 1 bbl/min THROUGH 1 ^{1/2} -in COILED TUBING			
Injection Fluid	Range of Calculated ▲P, psi	Average Measured ▲P, psi	Maximum Error, %
Water Preflush	1782-1800	1864	4.4
7000 ppm Polymer	1613-1849	1772	8.9
10,000 ppm polymer	2155-2188	2233	3.4

4.2.4 Polymer Mixing & Quality Control

A jet mixture was used to mix and hydrate the polymer to ensure wetting of each polymer particle. Two mixing tanks and one holding tank were used to ensure injection continuity and allow through hydration time before injection.

Sodium bicarbonate was premixed with the normal injection water (treated seawater) stored in the mud pits and was then pumped to the mixing skid. Solid polymer was then added to the jet mixer as the fluid was being pumped to the mixing tank. Finally, the organic crosslinkers were added to the jet mixer. The mixing tank was continuously agitated by a paddle mixer. After one batch was mixed, it was transferred to a second

stirred tank. As needed, the gelant in this tank was transferred to the holding tank that fed the injection pump. Batch mixing of all ingredients is preferred over "on the fly" mixing because of the excellent solution quality achieved. This mixing is subject to variations in concentrations dependent upon pump stroke timing and sudden line pressure surges.

Each 50 bbl batch was visually checked for fish eyes. Gelation time and gelation strength were measured on samples prepared in the field laboratory employing the actual delivered chemicals to detect any product variations from the design. Changes to the original designs were made based on these test results. The final mixtures included extra polymer to accelerate the gelation reaction and provide some marginal increase in gel strength.

Random samples throughout the treatment were obtained and placed in an oven at reservoir temperature to measure the gelation time and gel quality. The field mixed samples showed initially either the same or slightly faster gelation times than the laboratory-mixed samples. However final gel ratings were comparable to the laboratory prepared samples.

4.2.5 Returning the Lower Brent to Production

The shut-in time required for full gelation following a large volume gel placement is difficult to estimate. Calculations suggest that the bottomhole wellbore temperature decreased 90° F after 24 hours of injection at 1 bbl/min. Of greater concern, however, is the heating rate of the reservoir rock once injection stops because it is this temperature that dictates the speed of gelation. The bottomhole wellbore temperature after 24 and 48 hour shut in was estimated to increase 67 and 75° F, respectively.

These estimates of the bottomhole temperatures were determined with a wellbore simulator that predicts temperature swings as a function of production, injection, and shut-in periods. These data were combined with a thermal reservoir simulator to estimate reservoir cooling. Finally, a correlation of gel time vs. temperature derived from laboratory data was incorporated to predict the time required for complete gelation. The results indicated that a 21 hour shut in was required. However, because of operational requirements, the well was shut in for 48 hours. After the shut in period, a coiled tubing cleanout was completed by jetting 7.5% HCl acid through the gel cap and calcium carbonate. Production was resumed by gradually increasing the drawdown over a period of time to reduce shock to the newly formed gel.

4.3 Treatment Results

Following the gel treatment, the oil production increased 300 B/D. A production log run 8 months after the treatment indicated that the upper Brent to produce. Nearby water injection was shut in 2 months before the treatment to decrease pressure in the upper Brent sand. During this time, the produced water rate decreased and oil rate increased. This increase in oil production supported the diagnosis that the higher pressure upper Ness water production was restricting lower Brent oil production. At this point in time, controlling the injection rate was considered but dismissed because water would continue

to follow the path of least resistance. Shutting in water injection would provide a short-term oil gain because of pressure depletion in the upper Ness; however, long term benefits could be gained by shutting off upper Ness water production and providing continued pressure support to the lower Brent sands.

4.4 Polymer Treatments and Other Applications

The benefits of water shutoff treatment are wide ranging and can have significant secondary value beyond enhanced oil production from the treated well. For gas lift wells, significant reduction in gross fluid production decreases the required lift gas volumes. Also, the reduction of significant water production can prevent the separation and treating facility capacity from being exceeded thus maximizing oil production. Other potential uses for the high temperature organic polymer gel currently being evaluated for the Heather field follows: -

- Injection of larger volumes with longer gel times for use as a deep diverting gel to improve conformance of the injection water.
- Repair of casing leaks and/or halting of fluid migration behind pipe.

4.5 Conclusions

- The new high temperature organic polymer gel system successfully isolated the upper Brent water production in Heather field Well H-43. Oil production has increased and water production has decreased.
- The lower perforations were successfully isolated with sized calcium carbonate suspended in an HEC polymer solution. This technique was difficult to monitor because of the inclination of the well-bore.
- Pump shutdowns did not cause any pre-mature gelation and were not detrimental to the treatment. Batch mixing provided excellent quality gels that matched gel performance measured in lab.

The high temperature gel system required no pre-cooling of the near well-bore area.

Chapter – 5

Laboratory Studies

Lab experiment was carried out to optimize a gel solution for Beta field and a core flood studies were undertaken to check the relative permeability modification for oil and water phases on treatment. The characteristics of the Beta field are listed as follows:

- Temperature of field – 105°C
- Type of Rock – Carbonate
- Field – Offshore producing field
- Drive Mechanism – Active bottom water drive
- Problem – High water cut

Major studies were taken up to optimise the gel solution for application on producing wells to shut off water.

5.1 Objectives

The laboratory studies were done with the focus to achieve the following objectives

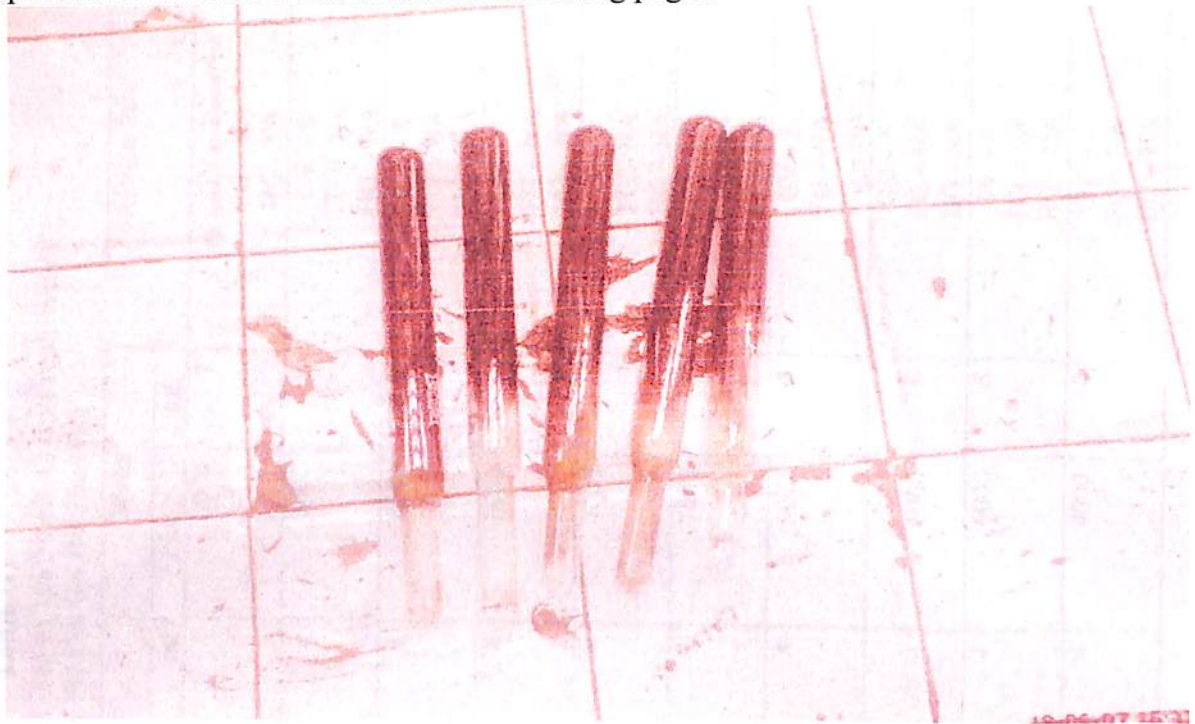
- To get an optimized gel system using polymer Alcoflood-955 and Alcoflood 935 with organic cross linkers, stable at Beta reservoir temperature of 105°C and compatible with formation water by extensive laboratory experimentations for field applications for controlling water production.
- To evaluate the effectiveness of the optimized polymer gel system on native cores of Beta reservoir by core flood studies.
- To calculate residual resistance factor.
- To design a tentative job plan for field application

5.2 Gellation studies

Basic gelation studies were carried out under field conditions for optimising the suitable gel formulations. The optimised gel system was used for coreflood studies to evaluate its effectiveness in reducing water permeability rather than oil permeability.

Various gel formulations using PHPA polymer Alcoflood-955 and Alcoflood-935, were prepared in sea water, distilled water concentrated with 1% NaHCO₃ and 1% NaHCO₃ + 1% NaCl in distilled water by varying the concentrations of polymer, organic crosslinking agents (Sea water and mixing waters were filtered to .45µm to remove suspended solids). The formulations were prepared (20 ml each) using different amounts of polymer, crosslinkers (hydroquinone and hexamine) and make-up water. These formulations were sealed in glass ampoules and kept in the oven for gelation at 105°C. Parameters like gelation time, gel strength and thermal stability were observed after

regular time intervals. While some of the gels formed showed extensive syneresis (defined as the water lost by the gel ultimately leading to an ineffective job due to gel compression) and broke away, some others formed very good gels that didn't break till the time they were observed (2 months). The different gel formulations prepared are presented in the form of tables in the following pages.



The results of these studies are summarised as:

5.2.1 Inferences

The gelation studies lead to the following inferences;

- The gelation time can be varied to the desired level by varying the concentration of polymer and crosslinkers. Larger the amount of polymer, quicker is the viscosity development.
- For the same amount of polymer, gelation is faster in case of more crosslinkers. Concentration of hydroquinone appears to affect gelation more in comparison to hexamine.
- The gels prepared in sea water showed extensive syneresis.
- The optimised gel suggested for field consists of a polymer concentration of 8000 ppm and HA and HQ concentration of 4500 ppm and 4000 ppm respectively.

Table G1
 Polymer: ALCOFLOOD 955 (2%) in 1% NaHCO₃ in Fresh Water
 *GV Good Viscosity FG Flex Gel HG Hard Gel

S No.	Polymer		HQ		HA		Water		Gelation time
	Ppm	ml	Ppm	ml	Ppm	ml	Ppm	ml	
1	5000	5	4000	4	4000	4	7000	7	GV - 7 FG - NA HG - NA
2	5000	5	3000	3	4000	3	8000	8	GV - 8 FG - NA HG - NA
3	5000	5	4000	4	3000	3	8000	8	GV - 8 FG - NA HG - NA
4	6000	6	4000	3	4000	4	6000	6	GV - 7 FG - NA HG - NA
5	6000	6	3000	3	4000	4	7000	7	GV - 7 FG - NA HG - NA
6	6000	6	4000	4	3000	3	7000	7	GV - 7 FG - NA HG - NA
7	7000	7	4000	4	4000	4	5000	5	GV - 5 FG - NA HG - NA
8	7000	7	3000	3	4000	4	6000	6	GV - 6 FG - NA HG - NA
9	7000	7	4000	4	3000	4	6000	6	GV - 6 FG - NA HG - NA
10	8000	8	4000	4	4000	4	4000	4	GV - 5 FG - NA HG - NA

Table G2
Polymer : ALCOFLOOD 955 (2%) in Sea Water
***GV Good Viscosity FG Flex Gel HG Hard Gel**

S No.	Polymer		HQ		HA		Water		Gelation time (Days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	5000	5	4000	4	4000	4	7000	7	GV -1 FG -2 HG -3
2	5000	5	3000	3	4000	4	8000	8	GV-1 FV-2 HG-3
3	5000	5	4000	4	3000	3	8000	8	GV - 1 FG -2 HG - 3
4	6000	6	4000	4	4000	4	6000	6	GV- 1 FG -2 HG -2
5	6000	6	3000	3	4000	4	7000	7	GV -1 FG -2 HG -3
6	6000	6	4000	4	3000	3	7000	7	GV -1 FG -2 HG -3
7	7000	7	4000	4	4000	4	5000	5	GV -1 FG -2 HG -2
8	7000	7	3000	3	4000	4	6000	6	GV -1 FG -2 HG -3
9	7000	7	4000	4	3000	3	6000	6	GV -1 FG -2 HG -2
10	8000	8	4000	4	4000	4	4000	4	GV -1 FG -2 HG -2

Table G3
 Polymer: ALCOFLOOD 955(2%) in 1%NaHCO3 in Sea Water
 *GV Good Viscosity FG Flex Gel HG Hard Gel

S No.	Polymer		Hydroquinone		Hexamine		Make up water		Gelation Time (days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	5000	5	4000	4	4000	4	7000	7	GV:1 FG:3 HG:4
2	5000	5	3000	3	4000	4	8000	8	GV:1 FG:2 HG:3
3	5000	5	4000	4	3000	3	8000	8	GV:1 FG:2 HG:2
4	6000	6	4000	4	4000	4	6000	6	GV:1 FG:2 HG:4
5	6000	6	3000	3	4000	4	7000	7	GV:1 FG:3 HG:4
6	6000	6	4000	4	3000	3	7000	7	GV:1 FG:2 HG:2
7	7000	7	4000	4	4000	4	5000	5	GV:1 FG:2 HG:2
8	7000	7	3000	3	4000	4	6000	6	GV:1 FG:2 HG:7
9	7000	7	4000	4	3000	3	6000	6	GV:1 FG:1 HG:4
10	8000	8	4000	4	4000	4	4000	4	GV:1 FG:1 HG:1

Table G4
Polymer: ALCOFLOOD 955(2%) in 1%NaHCO3 in Distilled water
***GV Good Viscosity FG Flex Gel HG Hard Gel**

S No.	Polymer		Hydroquinone		Hexamine		Make up water		Gelation Time (days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	6000	6	5000	5	4000	4	5000	5	GV:3 FG:NA HG:NA
2	8000	6	4000	4	5000	5	5000	5	GV:4 FG:NA HG:NA
3	6000	6	3500	3.5	3500	3.5	7000	7	GV:4 FG:NA HG:NA
4	6000	6	4000	4	3500	3.5	6500	6.5	GV:3 FG:NA HG:NA
5	6000	6	3500	3.5	4000	4	6500	6.5	GV:4 FG:NA HG:NA
6	8000	6	4000	4	4000	4	6000	6	GV:3 FG:NA HG:NA
7	7000	7	4000	4	4000	4	5000	5	GV:3 FG:NA HG:NA
8	7000	7	3500	3.5	3500	3.5	6000	6	GV:3 FG:NA HG:NA
9	7000	7	3000	3	3000	3	7000	7	GV:3 FG:NA HG:NA
10	7000	7	3000	3	3500	3.5	6500	6.5	GV:4 FG:NA HG:NA

Table G5
Polymer: ALCOFLOOD 955(2%) in 1%NaHCO3 in Distilled water
***GV Good Viscosity FG Flex Gel HG Hard Gel**

S No.	Polymer		Hydroquinone		Hexamine		Make up water		Gelation Time (days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	7000	7	5000	5	4000	4	4000	4	GV:1 FG:NA HG:NA
2	7000	7	4000	4	5000	5	4000	4	GV:1 FG:NA HG:NA
3	7000	7	4500	4.5	4500	4.5	4000	4	GV:1 FG:NA HG:NA
4	7000	7	5000	5	4500	4.5	3500	3.5	GV:3 FG:NA HG:NA
5	8000	8	3000	3	4000	4	5000	5	GV:1 FG:NA HG:NA
6	8000	8	4000	4	3000	3	5000	5	GV:1 FG:NA HG:NA
7	8000	8	3500	3.5	3000	3	5500	5.5	GV:1 FG:NA HG:NA
8	8000	8	3000	3	3500	3.5	5500	5.5	GV:1 FG:NA HG:NA

Table G6
 Polymer: ALCOFLOOD 955(2%) in 1%NaHCO₃ in Distilled Water
 *GV Good Viscosity FG Flex Gel HG Hard Gel

S No.	Polymer		Hydroquinone		Hexamine		Make up water		Gelation Time (days)	
	ppm	ml	ppm	ml	ppm	ml	ppm	ml		
1	6000	6	4000		4	6000	6	4000	4	GV:4 FG:NA HG:NA
2	6000	6	4000		4	6000	6	2000	2	GV:1 FG:NA HG:NA
3	7500	7.5	4000		4	6000	6	2500	2.5	GV:1 FG:NA HG:NA
4	10000	10	4000		4	6000	6	0	0	GV:1 FG:NA HG:NA

Table G7
Polymer: ALCOFLOOD 955(2%) in 1%NaHCO₃ + 1%NaCl in Distilled Water
***GV Good Viscosity FG Flex Gel HG Hard Gel**

S No.	Polymer		Hydroquinone		Hexamine		Make up water		Gelation Time (days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	5000	5	4000	4	4000	4	7000	7	GV:1 FG:NA HG:NA
2	5000	5	4000	4	3000	3	8000	8	GV:1 FG:NA HG:NA
3	5000	5	3000	3	4000	4	8000	8	GV:2 FG:NA HG:NA
4	6000	6	4000	4	4000	4	6000	6	GV:1 FG:5 HG:NA
5	6000	6	4000	4	3000	3	7000	7	GV:1 FG:8 HG:NA
6	6000	6	3000	3	4000	4	7000	7	GV:1 FG:5 HG:NA
7	7000	7	4000	4	4000	4	5000	5	GV:1 FG:6 HG:NA
8	7000	7	4000	4	3000	3	6000	6	GV:1 FG:4 HG:7
9	7000	7	3000	3	4000	4	6000	6	GV:1 FG:6 HG:8
10	8000	8	4500	4.5	4000	4	3500	3.5	GV:1 FG:4 HG:5

Table G8
 Polymer: 935 (20000 ppm) 1% Na₂CO₃ Fresh Water

Sr. No.	Polymer		HQ		HA		Water		Gelation time
	Ppm	ml	Ppm	ml	Ppm	ml	Ppm	ml	
1	6000	6	4000	4	4000	4	10000	6	Ampoule Damaged
2	6000	6	3000	3	3000	3	10000	8	GV - 6
									FG - 19
									HG - NA
3	6000	6	4000	4	3000	3	10000	7	GV - 6
									FG - 16
									HG - NA
4	6000	6	3000	3	4000	4	10000	7	GV - 7
									FG - 18
									HG - NA
5	7000	7	4000	4	4000	4	10000	5	GV - 5
									FG - 15
									HG - NA
6	7000	7	3000	3	3000	3	10000	7	Ampoule Damaged
7	7000		4000	3	3000	3	10000	6	GV - 5
									FG - 8
									HG - NA

8	7000	70	3000	3	4000	4	10000	6	Ampoule Damaged
9	8000	8	4000	4	4000	4	10000	4	GV - 5
									FG - 8
									HG - NA
10	8000	8	3000	3	3000	3	10000	6	GV - 5
									FG - 15
									HG - NA
11	8000	8	4000	4	3000	3	10000	5	GV - 5
									FG - 8
									HG - NA
12	8000	8	3000	3	4000	4	10000	5	GV - 5
									FG - 15
									HG - NA

***GV Good Viscosity FG Flex Gel HG Hard Gel**

Table G9
Polymer : 935 (20000 ppm)

Sea Water

Sr. No.	Polymer		HQ		HA		Water		Gelation time (Days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	6000	6	4000	4	4000	4	10000	6	GV - 2
									FG - 3
									HG - 7
2	6000	6	3000	3	3000	3	10000	8	Ampoule Damaged
3	6000	6	4000	4	3000	3	10000	7	GV - 2
									FG - 3
									HG - 6
4	6000	6	3000	3	4000	4	10000	7	GV - 2
									FG - 3
									HG - 6
5	7000	7	4000	4	4000	4	10000	5	GV - 2
									FG - 3
									HG - 6
6	7000	7	3000	3	3000	3	10000	7	GV - 2
									FG - 3
									HG - 6
7	7000		4000	3	3000	3	10000	6	GV - 2
									FG - 3

									HG - 6
8	7000	70	3000	3	4000	4	10000	6	GV - 2
									FG - 3
									HG - 6
9	8000	8	4000	4	4000	4	10000	4	GV - 2
									FG - 3 S
									HG - 6
10	8000	8	3000	3	3000	3	10000	6	GV - 2
									FG - 3
									HG - 8
11	8000	8	4000	4	3000	3	10000	5	Ampoule Damaged
12	8000	8	3000	3	4000	4	10000	5	GV - 2
									FG - 3
									HG - 6

***GV Good Viscosity FG Flex Gel HG Hard Gel**

Table G10
 Polymer : 935 (20000 ppm) 1% Na₂CO₃ Fresh Water

Sr. No.	Polymer		HQ		HA		Water		Gelation time (Days)	Gelation Stability (Days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml		
1	8000	8	5000	5	5000	5	10000	2	GV - 8	18
									FG - 12	
									HG - 30	
2	8000	8	5000	5	4000	4	10000	3	GV - 7	18
									FG - 12	
									HG - NA	
3	8000	8	4000	4	5000	5	10000	1	GV - 5	18
									FG - 12	
									HG - NA	
4	9000	9	4000	4	4000	4	10000	3	GV - 8	17
									FG - 13	
									HG - 30	

*GV Good Viscosity FG Flex Gel HG Hard Gel

Table G11
 Polymer : 254S (20000 ppm) 1% Na₂CO₃ Fresh Water

Sr. No.	Polymer		HQ		HA		Water		Gelation time (Days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	6000	6	4000	4	4000	4	10000	6	NG
2	6000	6	3000	3	3000	3	10000	8	NG
3	6000	6	4000	4	3000	3	10000	7	NG
4	6000	6	3000	3	4000	4	10000	7	NG
5	7000	7	4000	4	4000	4	10000	5	NG
6	7000	7	3000	3	3000	3	10000	7	NG
7	7000	7	4000	4	3000	3	10000	6	NG
8	7000	7	3000	3	4000	4	10000	6	NG
9	8000	8	4000	4	4000	4	10000	4	NG
10	8000	8	3000	3	3000	3	10000	6	NG
11	8000	8	4000	4	3000	3	10000	5	NG
12	8000	8	3000	3	4000	4	10000	5	NG

*NG No Gel

Table G12
 Polymer : 254S (20000 ppm) Sea Water

Sr. No.	Polymer		HQ		HA		Water		Gelation time (Days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	6000	6	4000	4	4000	4	10000	6	High synerisis along with incomplete and uneven gel formation
2	6000	6	3000	3	3000	3	10000	8	
3	6000	6	4000	4	3000	3	10000	7	
4	6000	6	3000	3	4000	4	10000	7	
5	7000	7	4000	4	4000	4	10000	5	
6	7000	7	3000	3	3000	3	10000	7	
7	7000	7	4000	4	3000	3	10000	6	
8	7000	7	3000	3	4000	4	10000	6	
9	8000	8	4000	4	4000	4	10000	4	
10	8000	8	3000	3	3000	3	10000	6	
11	8000	8	4000	4	3000	3	10000	5	
12	8000	8	3000	3	4000	4	10000	5	

Table G13Polymer: 254S (40000 ppm) 1% Na₂CO₃ Fresh Water

Sr. No.	Polymer		HQ		HA		Water		Gelation time (Days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	12000	6	5000	5	5000	5	10000	4	NG
2	12000	6	4000	4	4000	4	10000	6	NG
3	12000	6	4000	4	3000	3	10000	7	NG
4	12000	6	3000	3	4000	4	10000	7	NG
5	13000	6.5	5000	5	5000	5	10000	3.5	NG
6	13000	6.5	4000	4	4000	4	10000	5.5	NG
7	13000	6.5	4000	4	3000	3	10000	6.5	NG
8	13000	6.5	3000	3	4000	4	10000	6.5	NG
9	14000	7	5000	5	5000	5	10000	3	NG
10	14000	7	4000	4	4000	4	10000	5	NG
11	14000	7	4000	4	3000	3	10000	6	NG
12	14000	7	3000	3	4000	4	10000	6	NG

*NG No Gel

Table G14
 Polymer : 254S (40000 ppm) Sea Water

Sr. No.	Polymer		HQ		HA		Water		Gelation time (Days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	12000	6	5000	5	5000	5	10000	4	GV - 2
									FG - 3
									HG - NA
2	12000	6	4000	4	4000	4	10000	6	GV - 2
									FG - 4
									HG - NA
3	12000	6	4000	4	3000	3	10000	7	GV - 3
									FG - 4
									HG - NA
4	12000	6	3000	3	4000	4	10000	7	GV - 3
									FG - 4
									HG - NA
5	13000	6.5	5000	5	5000	5	10000	3.5	GV - 2
									FG - 3
									HG - NA
6	13000	6.5	4000	4	4000	4	10000	5.5	GV - 2
									FG - 3
									HG - NA
7	13000	6.5	4000	4	3000	3	10000	6.5	GV - 3
									FG - 4

										HG - NA
8	13000	6.5	3000	3	4000	4	10000	6.5		GV - 2
										FG - 3
										HG - NA
9	14000	7	5000	5	5000	5	10000	3		GV - 2
										FG - 3
										HG - NA
10	14000	7	4000	4	4000	4	10000	5		GV - 2
										FG - 3
										HG - NA
11	14000	7	4000	4	3000	3	10000	6		GV - 2
										FG - 4
										HG - NA
12	14000	7	3000	3	4000	4	10000	6		GV - 2
										FG - 7
										HG - NA

***GV Good Viscosity FG Flex Gel HG Hard Gel**

Table G15Polymer: 254s (200000 ppm) 1% NaHCO₃ Sea Water

Sr. No.	Polymer		HQ		HA		Water		Gelation time (Days)
	ppm	ml	ppm	ml	ppm	ml	ppm	ml	
1	2000	2	5000	5	3000	3	10000	10	GV - 3
									FG - 6
									HG - 16
2	1500	1.5	5000	5	3000	3	10000	10.5	GV - 3
									FG - 5
									HG - NA
3	3000	3	5000	5	3000	3	10000	9	GV - 2
									FG - 4
									HG - 6
4	4000	4	5000	5	3000	3	10000	8	GV - 2
									FG - 4
									HG - 11

*GV Good Viscosity FG Flex Gel HG Hard Gel

- The gel strength varies from light flexible gels to very good hard gels.
- The gels do not show any adverse effects on stability or strength when mixed with various proportions of formation water and rock cuttings.

Once the gelant system was identified, then a Beta field core (horizontal) was selected for the core flood experiment.

5.3 Core Selection

One core plug of Beta field having dia 3.8 cm and length 7.783 cm was used for the study. This plug was selected out of the batch of 5 cores selected from the store. The 5 core plugs were selected on the basis of random eye inspection. The core used for the coreflood experiment was selected after porosity and permeability measurement for 2 cores. The porosity and permeability results are shown in tables below.

Core Data Table - 4

Property	Sample No. 1	Sample No. 2
Length (cm)	7.783	6.127
Diameter (cm)	3.815	3.834
Dry weight (gm)	205.13	154.56
Bulk Volume (cc)	88.969	70.739
Bulk Density (gm/cc)	2.3056	2.1849
Saturated weight (gm)	2.6.467	167.022
Porosity (%)	20	18.2
Pore Volume (cc)	11.337	12.462
Permeability (md)	8.7	6.2

5.4 Core Cleaning

Prior to most laboratory measurements of porosity and permeability, the original fluids must be completely removed from the core sample. This is generally accomplished through flushing, flowing, or contacting with various solvents appropriate to extract hydrocarbons, water, and brine depending on the need.

Some solvents used for hydrocarbon extraction purposes are listed in Table 4. Listed solvents are those most frequently used for extracting samples for routine analysis. Some

are preferred for specific applications; e.g. toluene has been found useful for asphaltic crudes. Prior to cleaning samples with unknown oil properties, a sub-sample should be tested with various solvents for cleaning efficiency.

Table 5: Selected Solvents and Their Use

Solvent	Boiling Point, °C	Solubility
Acetone	56.5	oil, water, salt
Cyclohexane.	81.4	Oil
Ethylene Chloride	83.5	oil, water
Hexane	49.7-68.7	oil
Naphtha	40.1	oil, water
Toluene	65.0	oil, water, salt
Xylene	87.0	oil, water, salt
Acetone	138-144.4	Oil

5.4.1 Procedure

Once the right kind of solvent was selected, then the following procedure was undertaken to clean the core.

Distillation Extraction Method

A Soxlet extractor was used with acetone as a solvent to extract oil out of the core. During extraction, the oil-and water-laden solvent siphons from extractor into a still from which fresh solvent is continuously distilled, condensed, and again sent to the extractor.

The cleanliness of the sample was determined from the color of the solvent that siphoned periodically from the extractor. Extraction was continued until the extract remained clear.

It is to be noted that the complete extraction of certain oils from core samples may

require more than one solvent, and the fact that one solvent is clear after contact with the sample does not necessarily mean that oil has been completely removed from the sample.

5.4.2 Precaution

The following precautions were enforced during core sample cleaning operations:

- a. When using solvents, it is the responsibility of the user to establish appropriate safety and health practices prior to use and to comply with all applicable regulatory requirements regarding use and disposal of material.
- b. The solvent selected should not attack, alter, or destroy the structure of the sample.
- c. Closed-type electrical heaters should be used whenever inflammable solvents are used.

5.5 Core Drying

Table 6: Core Sample Drying Method

Rock Type	Method	Temp., °C
Sandstone (low clay content)	Conventional Oven	116
	Vacuum oven	90
Sandstone (high clay content)	Humidity Oven, 40% relative humidity	63
Carbonate	Conventional Oven	116
	Vacuum oven	90
Gypsum bearing	Humidity Oven, 40% relative humidity	60
Shale or other high clay rock	Humidity Oven, 40% relative humidity	60
	Conventional Oven	

Each core sample is to be dried until the weight becomes constant. Drying times may vary substantially, but are generally in excess of four hours. The core used was a carbonate core and so conventional oven was used for drying it. Dry weight of the cores was taken just after drying it.

Once the cores were cleaned and dried, they were sent for petrophysical analysis for estimation of porosity and permeability.

5.6 Conventional Core Analysis

5.6.1 Porosity

Porosity of a rock is the ratio of the pore volume to the bulk volume. In hydrocarbon reservoirs, the pore volume is the space available for oil, gas and water storage. Porosity is generally expressed as a percentage of bulk volume.

$$\phi = \left(\frac{V_p}{V_b} \right) \times 100$$

$$\phi = \left(\frac{V_b - V_g}{V_b} \right) \times 100$$

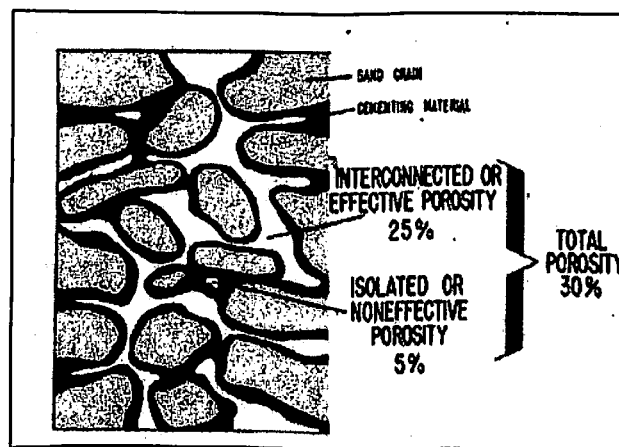
Where V_p = pore volume

V_g = grain volume

V_b = bulk volume

Total or Absolute Porosity: It is the ratio of the volume of all the pores to the bulk volume of the material, regardless of whether or not, all the pores are interconnected.

Effective porosity: It is the ratio of the interconnected pore volume to the bulk volume of the rock. The value of this parameter is used in all reservoir engineering calculations.



(After "Fundamentals of Core analysis", Core Lab, USA, 1989)

Determination of Porosity

The porosity is determined by core analysis or by well logging.

Core analysis

In core analysis, the cylindrical plugs of either 1.0 inch or 1.5 inch diameter are cut from whole core and then first cleaned and dried. In laboratory any two of V_p , V_b , V_g are measured and then porosity is determined.

Measurement of bulk volume

- Caliper method. The length and diameter of core plug is measured at different points of the core and averaged values are determined.

$$V_b = \frac{\pi d^2 l}{4}$$

- Measurement of the buoyancy exerted by mercury on the samples immersed in it.

The mercury based methods are not used for rocks containing fissures or macro pores because of possibility of mercury penetration.

Measurement of pore volume

The pore volume can be measured:

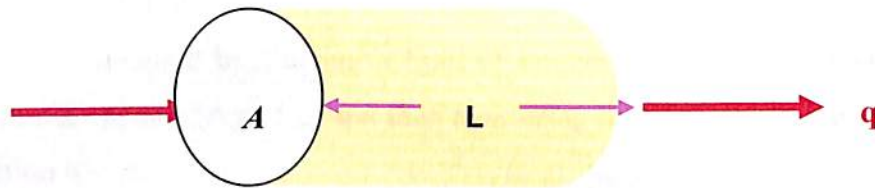
- Helium expansion in the interconnected pores
- Measurement by weighing in a fluid filling the effective pores
- Measurement by mercury injection

Effect of Pressure on Porosity

Porosity decreases with increasing net overburden pressure. Reservoir rocks experience the lithostatic pressure and fluids pressure in the pores. The production of hydrocarbons causes a decline in the fluid pressure in the pores resulting in compression of the rock, until a new equilibrium is attained.

5.6.2 Permeability

Permeability is a measure of the capacity of formation to transmit fluids. Unit of permeability is Darcy, named after a French scientist Henry Darcy in 1856. One Darcy equals permeability that will permit a fluid of one centipoise viscosity to flow at a rate of one cubic centimeter per second through a cross-sectional area of one square centimeter when the pressure gradient is one atmosphere per centimeter. Generally permeabilities are given in millidarcies which is equal to (1/1000) of a Darcy. Its dimension is L^2 .



$$K = (Q \mu L) / (A \Delta P)$$

ΔP

ΔP = Pressure Gradient

A = Cross-sectional area

K = Permeability, darcy

Q = Outlet Flow Rate, cc/sec

μ = Fluid Viscosity, cp

L = System Length, cm

Darcy law is used to determine permeability when the following conditions exist:

- Laminar flow
- No reaction between fluid and rock
- One phase present at 100 percent pore space saturation.

The measured permeability at 100% saturation of a single phase is called the absolute permeability of the rock.

The following terms are generally used to specify the permeability:

<1mD = Very low

1to 10 mD = Low

10 to 50 mD = Medium

50 to 200 mD = Good

200 to 500 mD = Very Good

>500 mD = Excellent

The factors which control magnitude of permeability are:

- Shape and size of sand grains
- Lamination
- Cementation
- Fracturing and solution

Measurement of Permeability

The permeability is measured by flowing a fluid of known viscosity μ through a core plug of measured dimensions (A and L) and then measuring flow rate q and pressure drop ΔP . Darcy equation becomes

$$k = \frac{q\mu L}{A\Delta p}$$

Absolute permeability is usually determined by flowing air through the core plug because of its convenience and to minimize rock-fluid interaction

Once the porosity and permeability measurements, the cores were placed in a vacuum desiccator to bring out any air present in them. The vacuum desiccator was connected with vacuum pump for about an hour. After that the dessicator was filled with Beta Field injection water (the water was filtered using a .45 micron filter paper before this). Care must be taken to avoid entry of any air into the dessicator. Vaccum pump is again run to bring out any traces of air that may have entered during the process.

The desiccator was kept for one complete day so that the core plugs become fully saturated with water. After which weight of the plug was taken to obtain the wet weight. The difference between the dry weight and the wet weight gives the pore volume.

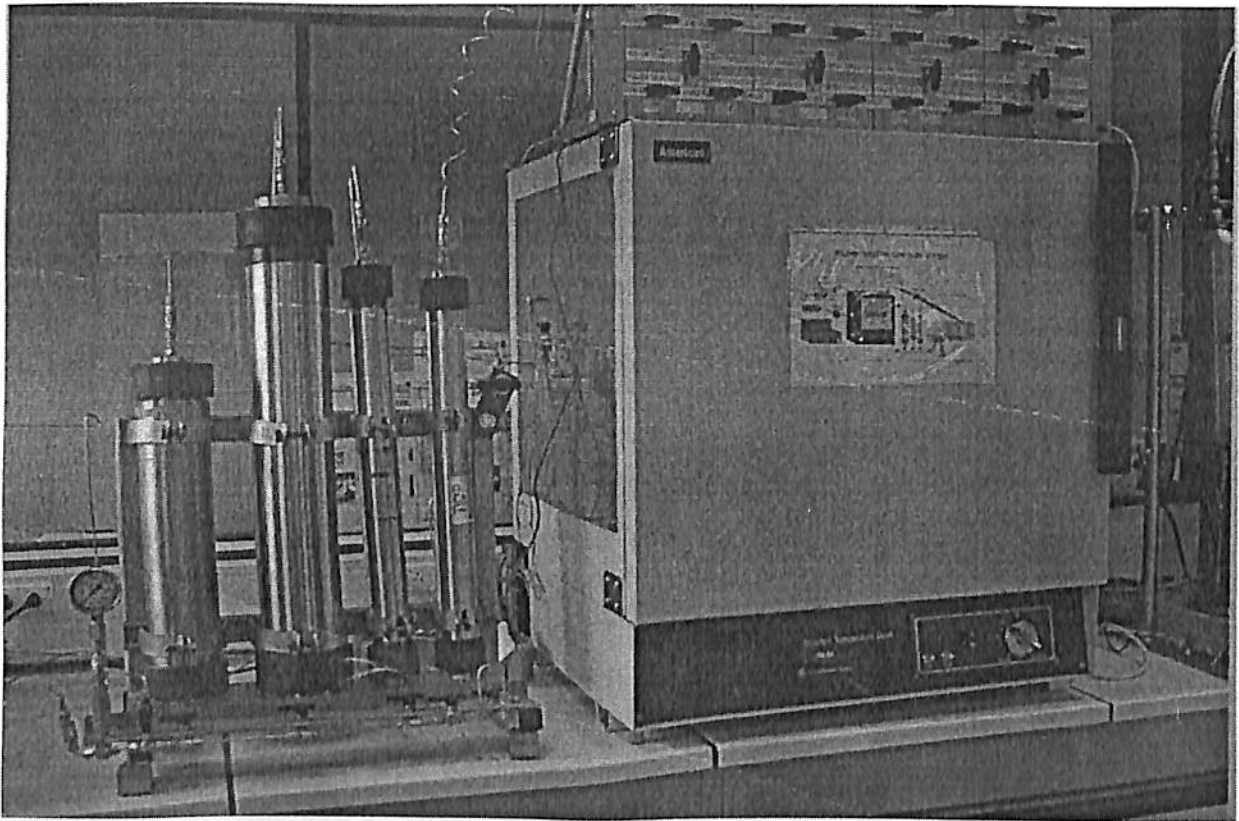
$$\boxed{\text{Weight of liquids removed from sample}} = \boxed{\text{Weight of original saturated sample}} - \boxed{\text{Weight of desaturated and dried sample}}$$

5.7 Coreflood Experiment

The objective of this study was to evaluate the effectiveness of gel system on the cores of Beta field reservoir in terms of permeability reduction. The residual resistance factor (Frr) which is obtained as the ratio of permeability before the chemical treatment to permeability after the chemical treatment is calculated to determine the percentage damage (% damage) to phase permeability.

The gel performance characteristics like permeability reduction, compatibility with reservoir rock help in designing the gel treatment for application in the well.

Once the core was water saturated, it was sealed in the core holder using molten Cerrometal. The core holder was then placed into the oven.



In this way, the core was made ready for core flood experiment. Beta field injection water was filled in the cell and connections were appropriately made and pressure gauges were put in place. A proportionating pump was used to generate the pressure required. The pump uses kerosene as a displacing medium.

The initial reservoir conditions were created in the core at 105°C. The core was water flooded and the readings of pressure and cumulative volume were taken every 15 minutes. The pump discharge was set at 25 cc/hr. The stabilised pressure thus obtained enables us to calculate the water permeability (absolute) of the water saturated core.

5.7.1 Water Flooding

Field injection water was filled in the cell and connections were appropriately made and pressure gauges were put in place. A proportionating pump was used to generate the pressure required. The pump uses kerosene as a displacing medium.

The initial reservoir conditions were created in the core at 105°C. The core was water flooded and the readings of pressure and cumulative volume were taken every 15 minutes. The pump discharge was set at 25 cc/hr. The stabilised pressure thus obtained enables us to calculate the water permeability (absolute) of the water saturated core.

By Darcy's Law we can determine the Absolute permeability with formation water.

$$K = (Q \mu L) / (A \Delta P).$$

Where $Q = 25$ cc/hr.

$\mu = 0.4$ cp

$L = 7.783$ cm

$R = 1.9$ cm

$\Delta P = 0.81$ psia ---- average stabilized pressure.

The absolute permeability comes out to be $K_w \text{ abs.} = 8.476$ md



Coreflood Apparatus (RUSKA Proportionating Pump), Courtesy ONGC

5.7.2 Crude Flooding

Once considerable amount of water had passed through the core, the apparatus was changed to crude flood by attaching a crude filled cell between core and water cell. Pumping was continued and readings were similarly taken. The stabilised pressure enables us to calculate the effective oil permeability. The core, after this flood has reached the initial reservoir conditions (S_{wi}).

$$K = (Q \mu L) / (A \Delta P).$$

Where $Q = 25$ cc/hr.

$$\mu = 0.45 \text{ cp}$$

$$L = 7.783 \text{ cm}$$

$$R = 1.9 \text{ cm}$$

$$\Delta P = 3.9 \text{ psia} - \text{average stabilized pressure}$$

The effective permeability of oil phase comes out to be

$$K_o \text{ eff.} = 1.76 \text{ md}$$

5.7.3 Water Flooding

The core was again water flooded and the stabilised pressure enables us to calculate the effective water permeability. The core, after this flood has reached the residual oil saturation (S_{OR}) condition. Thus the condition is now that of a depleted reservoir.

$Q = 25$ cc/hr.

$$\mu = 0.4 \text{ cp}$$

$$L = 7.783 \text{ cm}$$

$$R = 1.9 \text{ cm}$$

$$\Delta P = 3.1 \text{ psia} - \text{average stabilized pressure.}$$

The effective permeability of water phase comes out to be

$$K_w \text{ eff.} = 2.21 \text{ md}$$

5.7.4 Polymer Flooding

The optimised pre gel solution (gelant) using polymer Alcoflood 935, hexamine and hydroquinone of the optimised composition (0.7%, 0.4%, 0.3% respectively) in injection water of Beta field was used for flood experiments. While the experiment, readings for

pressure and cumulative volume were continuously taken. Once the polymer flood was over, core was kept in the oven for 5 days under reservoir temperature for aging.

5.7.5 Water and Oil Flooding

After the stipulated time period, the Beta formation water and oil were flowed in sequence through the core till the pressures were stabilized. Pressure differential across the core and pore volume injected were recorded. The post treatment water and oil floods enable us to know the effective water and oil permeability after the treatment.

Disproportionate permeability reduction can be calculated once dividing the permeability before by the permeability after the job both for water and oil. For a successful experiment, the DPR value for water should be more than that for oil.

The effective water permeability after polymer injection comes out to be:

$$Q = 25 \text{ cc/hr.}$$

$$\mu = 0.4 \text{ cp}$$

$$L = 7.783 \text{ cm}$$

$$R = 1.9 \text{ cm}$$

$$\Delta P = 15.2 \text{ psia} - \text{average stabilized pressure.}$$

$$K_{wg} = 0.451 \text{ md}$$

The effective oil permeability after polymer injection comes out to be:

$$Q = 25 \text{ cc/hr.}$$

$$\mu = 0.4 \text{ cp}$$

$$L = 7.783 \text{ cm}$$

$$R = 1.9 \text{ cm}$$

$$\Delta P = 9.4 \text{ psia} - \text{average stabilized pressure.}$$

$$K_{og} = 0.73 \text{ md}$$

The results can therefore be summarized as follows:

<u>Before the treatment</u>		
$K_w \text{ abs}$	$K_o S_{wi}$	$K_w S_{or}$
8.476 md	1.76md	2.21md
<u>After the treatment</u>		
$K_{og} S_{wi}$	$K_{wg} S_{or}$	
0.73md	0.451md	

percentage reduction

$$F_{ro} = K_o/K_{og} = (1.76/0.73) = 2.41$$

$$F_{rw} = K_w/K_{wg} = (2.21/0.451) = 4.90$$

Thus $F_{ro} < F_{rw}$, the experiment is a success.

Reduction in water permeability is 79.59%

Disproportionate permeability reduction (DPR) can be calculated once dividing the permeability before by the permeability after the job both for water and oil. For a successful experiment, the DPR value for water should be more than that for oil.

Residual resistance factor **Frr** which is a measure of permeability reduction was evaluated for water and oil and plotted against cumulative fluid flushed to see the effect on the permeabilities after and before the floods of each phase. The table for Frr calculation is shown in the following pages.

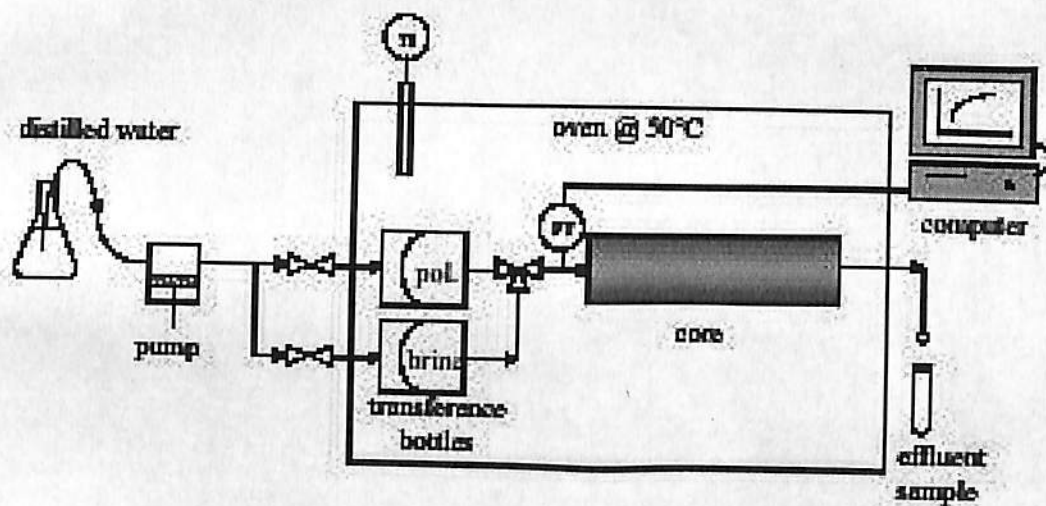


Fig. Experimental Setup for Core flood study

CORE FLOW STUDY

Length: 7.783 cm

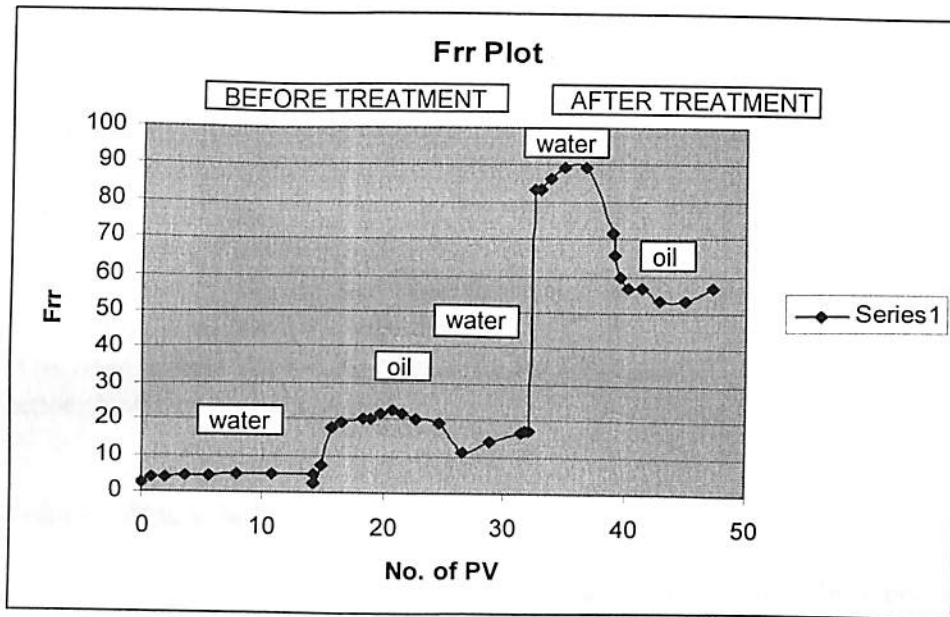
Diameter: 3.815 cm

Porrosity: 20 %

Pore Volume: 11.337 cc

Water Viscosity:
at 80oC: 0.4cp

Volume cc	Cum. Vol. cc	No. of PV		Rate of flow cc/hr	Delta Press Kg/cm2	Kw , Perm md	K/Kw	Time min	kw/k=frr
0.55	0.55	0.0275	water	25	0.4	3.553274	0.419216	15min	0.281431
15	15.55	0.7775		25	0.69	2.059869	0.243024	15min	0.485468
25	40.55	2.0275		25	0.69	2.059869	0.243024	15min	0.485468
32	72.55	3.6275		25	0.7	2.030442	0.239552	15min	0.492504
39	111.55	5.5775		25	0.7	2.030442	0.239552	15min	0.492504
46	157.55	7.8775		25	0.79	1.799126	0.212261	15min	0.555825
57	214.55	10.7275		25	0.8	1.776637	0.209608	15min	0.562861
68	282.55	14.1275		25	0.8	1.776637	0.209608	15min	0.562861
2	284.55	14.2275	oil	25	0.4	3.553274	0.419216	15min	0.281431
12	296.55	14.8275		25	1.2	1.184425	0.139739	15min	0.844292
15	311.55	15.5775		25	3	0.47377	0.055895	15min	2.11073
18	329.55	16.4775		25	3.2	0.444159	0.052402	15min	2.251445
35	364.55	18.2275		25	3.4	0.418032	0.04932	15min	2.39216
13	377.55	18.8775		25	3.4	0.418032	0.04932	15min	2.39216
17	394.55	19.7275		25	3.6	0.394808	0.04658	15min	2.532876
18	412.55	20.6275		25	3.8	0.374029	0.044128	15min	2.673591
19	431.55	21.5775		25	3.6	0.394808	0.04658	15min	2.532876
20	451.55	22.5775		25	3.4	0.418032	0.04932	15min	2.39216
39	490.55	24.5275		25	3.2	0.444159	0.052402	15min	2.251445
42	532.55	26.6275	water	25	1.9	0.748058	0.088256	15min	1.336795
45	577.55	28.8775		25	2.4	0.592212	0.069869	15min	1.688584
50	627.55	31.3775		25	2.8	0.507611	0.059888	15min	1.970014
6.5	634.05	31.7025		25	2.9	0.490107	0.057823	15min	2.040372
9	643.05	32.1525	gel	25	2.9	0.490107	0.057823	15min	2.040372
4	647.05	32.3525	water	25	14	0.101522	0.011978	15min	9.850072
12	659.05	32.9525		25	14	0.101522	0.011978	15min	9.850072
16	675.05	33.7525		25	14.5	0.098021	0.011565	15min	10.20186
22	697.05	34.8525		25	15	0.094754	0.011179	15min	10.55365
36	733.05	36.6525		25	15	0.094754	0.011179	15min	10.55365
45	778.05	38.9025	oil	25	12	0.118442	0.013974	15min	8.442919
5	783.05	39.1525		25	11	0.12921	0.015244	15min	7.739342
8	791.05	39.5525		25	10	0.142131	0.016769	15min	7.035766
14	805.05	40.2525		25	9.5	0.149612	0.017651	15min	6.683977
23	828.05	41.4025		25	9.5	0.149612	0.017651	15min	6.683977
27	855.05	42.7525		25	9	0.157923	0.018632	15min	6.332189
43	898.05	44.9025		25	9	0.157923	0.018632	15min	6.332189
46	944.05	47.2025		25	9.5	0.149612	0.017651	15min	6.683977



5.7.6 Precautions and Sources of Error

- Random core selection must be proper for the experiment to be a success.
- Soxhletion should be done properly and no oil content should be left in the core.
- Porosity and permeability values should be measured properly and with utmost care.
- Sufficient time must be given for de-aerating and water saturating the core
- Weights must be properly measured for the correct value of pore volume.
- Core sealing should be properly done and any leakages should be avoided.
- Core flooding apparatus should be cleaned properly before the experiment and before each new flood. Care must also be taken to fill the flow lines with the fluid to be injected to avoid entry of air in the core.
- Connections should be continuously monitored for leakages, if any.
- Gel selection for core flood should be appropriate.
- Pump must always be checked for the proper amount of kerosene every time before starting the experiment.
- Pressure should be recorded carefully and if limit of any gauge is crossed, then its valve should be immediately closed.
- The core holder should be placed in the oven immediately in the oven for aging after attaching end plugs to it.

5.7.7 Well Candidate Selection

Best candidates are shut-in wells or wells producing at or near their economic limit. These wells benefit most from a successful treatment and little is at risk if the treatment fails, other than the treatment cost. Other selection criteria include significant remaining mobile oil in place, high water-oil ratio, high producing fluid level, high initial productivity, wells associated with active natural water drive, structural position and high permeability contrast between oil and water-saturated rock (i.e., vuggy and/or fractured reservoir). Successful treatments have been conducted in both cased and open hole completions.

The following points are taken into consideration for initial screening of the wells:

- Good productivity of the well with water cut more than 80%.
- Sufficient movable oil saturation.
- Preferential movement of water.
- Good mechanical completion.

The reasons for high water cut may be analyzed by a systematic evaluation of the production history and diagnostic plots. Although linear plots of water cut versus time show the progress and severity of water cut, they were all similar regardless of the problem being encountered in the reservoir unless otherwise it is a sudden completion failure. Hence diagnostic plots between the derivatives of WOR against time were used to

differentiate between water production problem due to coning or multilayer channeling. After studying diagnostic plots it can be concluded that the problem is of channeling hence we can go for polymer gel treatment. Then wells can be selected after extensive discussions with the asset and the job plans can be finalized.

Treatment Design

Many details are taken into consideration while designing the treatment. The quantity of the chemical to be pumped is calculated taking into consideration the production potential, perforation interval, reason of high water cut. The type of gel to be used also prompted the concentrations of the chemicals used for treatment.

Gelant Volume

The gelant volume planned to be injected is based upon the well analysis. Initially, a gel volume of 60 m³ for well may be required for treatment on trial basis. Though higher gel volume is desirable for extending the life of treatment, the other parameters like gel placement, damage to less permeable layers restricted the use of high volume at trial stage. Once post treatment results are known, further improvement in job design can be planned for subsequent wells.

Tentative Job Plan To Be Carried Out in Field

Well number, sand type and perforation interval from which water is getting produced is known to us after the selection of well candidate. Present status of well like total liquid production, oil production and water cut data is gathered.

- All surface equipments i.e. tanks, pumper, manifolds etc may be cleaned.
- Injectivity may be tested. It should be around 2 bpm at 1000 psi. If less, carry out acid job and get desired injectivity.
- Chemical requirement for carrying out the job should be calculated and made available at the field. Polymers AF-935 and AF-955 are available in the local market. Organic crosslinkers and Sodium bicarbonate are locally available (LR grade quality with purity not less than 99%).
- Gel solution is prepared in the field itself and is pumped at the rate of 1.5 bpm. The pressure should not exceed 200psi.
- The whole solution may be post flushed with around 10 bbl of fresh water followed by around 50 bbl sea water.
- The well may be closed for a period of 5 to 6 days and then flowed again.

Monitoring

- Liquid rate, oil rate, and water cut may be measured after stabilization
- The water cut may be measured once in a week and oil rate once in a month for a period of one year.

5.7.8 Result and Discussion

The Frr value for water under stabilized conditions is 4.90 while in case of oil it is 2.41. Higher value of Frr in case of water than that of oil after polymer gel treatment indicates reduction in water permeability to a larger extent than that of oil phase. The permeability reduction in case of water phase is 79.59 %.

5.7.9 Conclusion

On the completion of this project, the following conclusions can be made:

- The optimised gel consists of 8000 ppm PHPA polymer, 4500 ppm hydroquinone and 4000 ppm hexamine and has a gelation time of 5 days.
- The coreflood experiment suggests that this polymer brings a 79% reduction in the effective permeability to water.
- After the treatment, the effective permeability to oil is larger than that to water which is also very clear from the Frr plot.

5.8 What's New in Water Management?

A major challenge in today's petroleum industry is minimizing the amount of water that enters a well bore and is subsequently produced. Fortunately, many strategies and solutions are currently available, some involve mechanical tools while others use cement or chemicals to manage unwanted water production. However, many operators do not consider these solutions and technologies when they want to reduce unwanted water production and improve overall field economics.

To appreciate what is new in water management, it is important to understand the global impact produced water has on the oil and gas industry. It is estimated that in 1999 an average of 210 million bbl of water was produced each day worldwide.

A large percentage of produced water is used for pressure maintenance and enhanced recovery. A 1995 API study found that management and disposal of exploration and production waste was following a trend toward less discharge and more reuse, recycling and reclamation. API's study indicated that about 71% of all produced water was being injected for enhanced recovery while 21% was being injected for disposal. The remaining 8% was treated and discharged, disposed of or beneficially used.

If the sheer volume of produced water does not cause our industry to take notice, its financial impact should. Costs can run from US \$0.02/bbl to as much as \$2.50/bbl, depending on location and volume. Accordingly, the average cost to produce 1 bbl of water is \$0.10, making the annual expenditure \$7.7 billion. In addition, produced water results in lower production rates, a reduction in recoverable reserves and potential negative environmental impact.

New Water Management Treatment Simulator

What if we could take diagnostic information from a well, simulate a treatment or shutoff operation, and accurately predict the results of the operation? A new simulator offers a unique combination of features that can help optimize the design and placement of water control treatments and predict their effects on production (Figure below). By numerically simulating the flow of oil, gas, water, conformance fluid and heat through a porous medium in three dimensions, the simulator enables initial reservoir conditions to be quickly and easily set up. A number of wells with various flow constraints can be handled simultaneously. The simulator's local grid refinement works both horizontally and vertically to model near-wellbore effects such as those caused by conformance fluid injection, coning, or field-scale simulations. In addition, the simulator can model deeper reservoir effects such as those from communication through a fracture or a high permeability streak. And, it accurately models conformance fluid placement by incorporating the thermal and fluid viscosity effects in both the reservoir and the well bore.

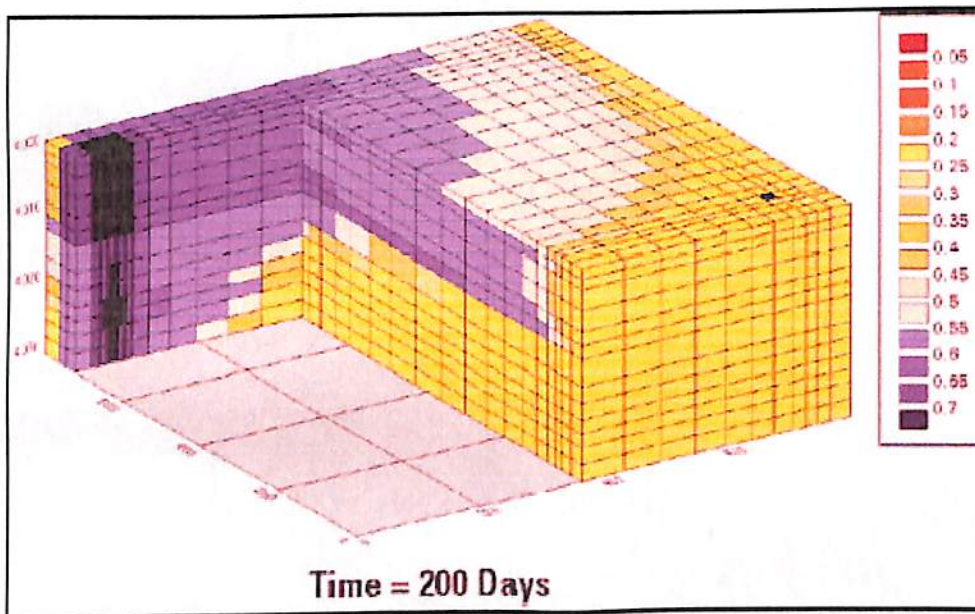


Figure: Simulator output showing a water saturation profile of an injector producer channelling through a high-permeability zone. (Image courtesy of Halliburton)

The new simulator was developed to optimize the design and placement of treatments to shut off production of unwanted fluid. As the only reservoir fluid management technology created specifically for oil industry conformance applications, it allows data to be interpreted with unprecedented speed and accuracy. Processes that once took days or weeks to complete with a typical reservoir simulator now require only a few hours. Using this revolutionary approach, you can predict the economic outcome and make quicker, more accurate and more proactive decisions to maximize production and efficiency.

The new simulation software is exceptionally versatile. Its reservoir fluid management tool has a superior graphic interface that enables operators to enter complex well data, check data consistency, produce supplemental plots, display interactive graphics, launch and monitor simulation runs, and analyze results.

Simulator capabilities include the following:

- Production history matching evaluated against wellbore and reservoir diagnostics to more accurately determine well and reservoir flow characteristics.
- Water shutoff or reduction design maximized and simulated based on reservoir characterization from simulation and history match.
- Forecasting of production resulting from treatments applied to both simple and complex reservoirs and/or wells.
- Reduction of economic and operational risks through better candidate selection, diagnostics, evaluation, and treatment.

New Relative Permeability Modifier

In addition to an improved capability to diagnose, evaluate, and simulate, a new treatment system has also been introduced (Figure below). The new system can be bullheaded into a well to greatly reduce permeability to water with little or no restriction to hydrocarbon flow. This new approach uses unique polymer chemistry to help create oilwater separation in the reservoir, thereby impeding water flow and enhancing hydrocarbon flow to the well bore. Called a relative permeability modifier, the polymer works by adsorbing onto the rock surface and reducing permeability to water by a factor of seven to 10 compared to hydrocarbons.

Features of the new treatment include:

- Requires no special placement techniques;
- Unaffected by multivalent cations, oxygen, and acids;
- Does not require rig time, zonal isolation, or a catalyst;
- Does not gel or "set up."

This treatment can also be incorporated into the new simulator to determine whether it the best technical and economic solution for the well.

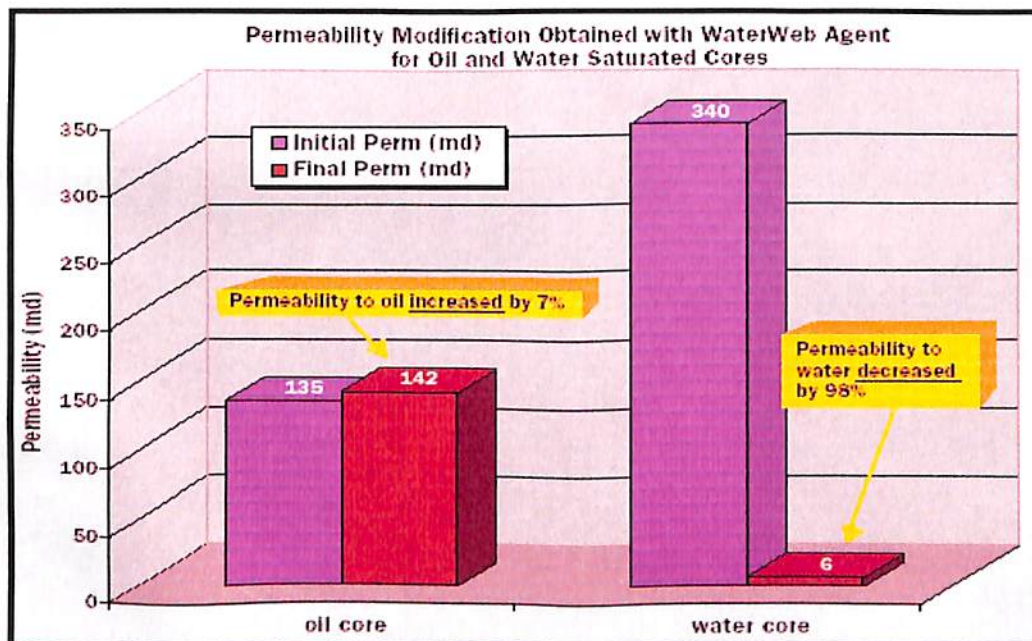


Figure. Typical permeability modification results seen using the new relative permeability modifier with a large number of cores over a broad permeability and temperature range. (Graph courtesy of Halliburton Summary)

Summary

Today, a full range of solutions is available for almost any near-wellbore or reservoir-related produced water challenge. In addition, a range tools and techniques is available to properly diagnose wellbore and reservoir characteristics. Most importantly, a new treatment simulator has been developed that enables us to determine which treatment will provide the best overall technical and economical solution. Selective gels preferentially blocking water phase in the reservoir make well treatments attractive, especially for advanced wells with complicated completion design (deviated, horizontal, multilateral). In spite of relatively small volume of chemicals involved in well treatments, evaluations of potential and possible benefits of near well treatments remain an important issue. Accurate near well model is required to simulate production of the well and effects of chemical treatment in the near well bore. Correct modelling of inflow is as important as representative modelling of get generation process. Fine grid radial models allow accounting more accurately for near well reservoir properties based on available log, core and production data. Template well models were established and used for screening of potential candidate wells for treatments. They proved to be useful in history matching and evaluating treatment effect in several field pilots in the North Sea. By working together, service companies and operators can reduce overall water production effectively with an attractive economic return to the operator. But in order to move forward, the industry must understand that the impact of produced water is much more significant than currently recognized and that the problem is manageable.

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