AZERBAIJAN REPUBLIC MINISTRY OF EDUCATION

KHAZAR UNIVERSITY

School of Architecture, Engineering and Applied Science
Major: Petroleum Engineering and Management

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M.Sc.THESIS

WATER INJECTION IN AZERI–CHIRAG–GUNESHLI OILFIELDS

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BAKI 2009

ABSTRACT

The present thesis is devoted to topical research problem – efficiency of Azeri-Chirag-Guneshli (ACG) oilfields with injection of water while allowing maximum well & field productivity

The brief geological, field development and operational characteristics along with work conditions of the Azeri-Chirag-Guneshli oilfields are examined and described in the work.

Water injection is an essential part of many modern oilfield development plans. High cost offshore developments require that the waterflood process equipment is designed and installed prior to acquiring any injection experience on that particular project. The choosen design must not only maximize the oil production revenue, but also carry a acceptable level of risk in terms of the project costs and technical uncertainties. Well injectivity, which describes the well to reservoir connection, is a central factor in any water injection operation. The formation characteristics, water properties, well configurations and injection water pressure determine this.

Properties of injection water one of the most important factors defining the injectivity. "Water Quality" is determined by source of the water injection and its treatment prior to injection.

The urgency target of the thesis theme is proved and the brief review of research works in the given area is made.

Conclusions are made at the end of the thesis and results of the research can be applied in other offshore oilfields.

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INTRODUCTION

Urgency of a theme

The oilfields of Caspian Sea where Waterflooding is required are: Azeri, Chirag and Deepwater Guneshli, key factors affecting to water injection performance are discussed with value of waterflooding on Caspian sea

The object of the thesis

The present thesis main aim is based on water injection performance and parameters impact the performance of water injection project is briefly described with ,waterflood efficiency, well design and water injection rate calculations. . Guidance about selection of well patterns is supported with graphs. Brief review on Topsides of particular project is given as well. Methods to improve the value of the water injection from economics point of view is also been considered.

One of the most important factors responsible for the success or failure of a waterflood is the fluid saturation at the start of the flood. It is difficult to have an economic waterflood at water saturation of 50% or more. However, it is possible to conduct a successful waterflood with connate water saturations as high as 50% or more, only if a favorable combination of other factors are present.

The objective of any water-injection operation process is to inject water into the reservoir rock without plugging or permeability reduction, dispersed oil, scale formation, bacterial growth or clay swelling. In addition, souring of sweet reservoir by sulfate-reducing bacteria should be prevented as well.

Waterflooding may be classified into peripheral and pattern waterfloods. Many factors need to be considered in the selection of a flood pattern for a project. From technical and process stand point, the most important factors are injection rate, response time, production rate, and the mobility ratio.

Water injection rate is critical parameter in a waterflood design. Since the oil production rate is function of water injection rate, the water injection rate must be maintained at a level that would make the waterflood project profitable.

An important factor in the success of a waterflooding project, although often neglected in production engineering, is the quality of the water required for injection into the reservoir rocks. There are four main problems with injection water: 1) dissolved solids in the injection water that can precipitate and form scale, 2) oil and suspended solids that can plug wellbores, 3)oxygen in the water that can cause corrosion and suspended solids, and 4) bacteria in the system that can cause corrosion and suspended solids. Therefore water must be carefully sampled and characterized. The following measurements are considered essential: chemical composition, dissolved gases, corrosivity, bacteria, suspended solids, and oil content.

Today's economic environment requires oil companies not only to consider water injection as cost, but as an operation generating additional value to asset. Difference in the field value with and without waterflooding represents the value of the water injection. Integration of the key technical and economical elements allows the development of a historic approach to the water injection process.

Ways of problems solving considered

Predictions of future reservoir performance for waterflood and water injection projects provide the basis for the economic evaluation of the profitability of proposed project. Therefore, optimization of watreflooding performance is a necessary part of reservoir management.

Matter of thesis

The Thesis includes introduction, four chapters, conclusion and reference.

In section 1 general information of Azeri-Chirag-Guneshli oilfields is given. Geological and field development characteristics are described.

In section 2 detailed study of injection performance is given. Types of waterflood and flood patterns, and factors that need to be considered in pattern selection are considered.

In section 3 factors affecting waterflood efficiency, displacement , sweep efficiency, key factors to be considered during displacement oil by injected water are given

In Section 4 methods may be used to estimate the water injection rate on single and multi wells is talked about.

In section 5 topsides overview of particular project and how water quality is controlled on that installation is described, and examples of application of an Integrated Technical and economic model of water injection economics are given

At the end of the thesis conclusion about waterflooding is made and references are given.

1. INFORMATION ABOUT AZERI-CHIRAG-GUNESHLI OILFIELDS

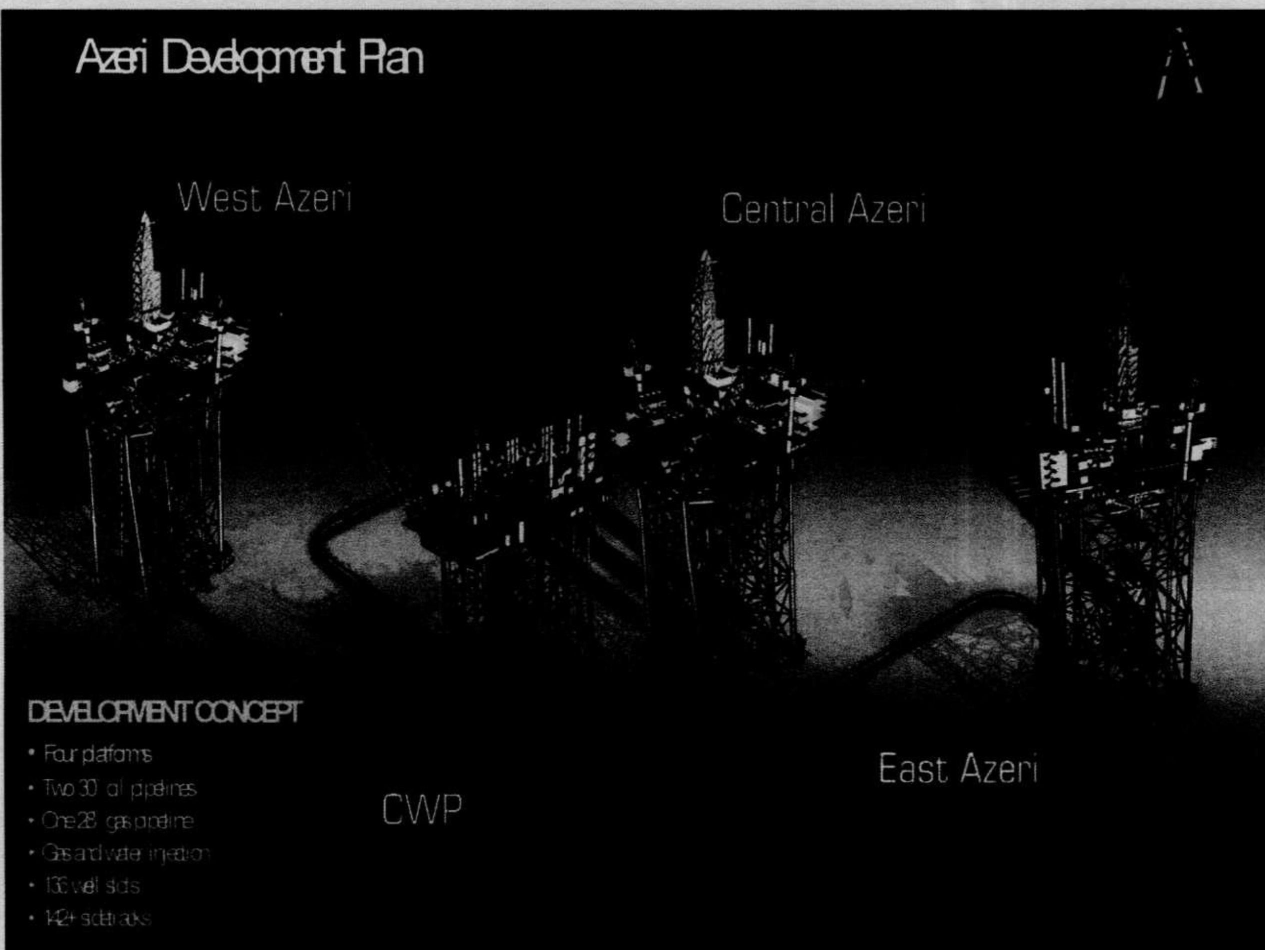
The ACG Oil Field is situated to the SE of Baku, offshore Azerbaijan in water depths of between 60m and 280m. The ACG structure is comprised of three linked culminations, which are, from west to east Shallow Water Gunashli (not in PSA), Deep Water Gunashli, Chirag and Azeri.

The AIOC (Azerbaijan International Oil Company) consortium, made of 10 different oil companies, from 6 different countries agreed the Production Sharing Agreement (PSA) terms with Azerbaijan in December, 1994.

The PSA term is for 30 years at which time the field will revert back to Azerbaijan. BP operates the field on behalf of the shareholders which include the following companies: BP 34.14%, UNOCAL 10.28%, SOCAR 10%, LUKOIL 10%, Statoil 8.56%, ExxonMobil 8%, TPAO 6.75%, Devon 5.63%, Itochu 3.92% and Delta Hess 2.72%.

The ACG structure covers approximately 135 square kilometers and has had a two phases of appraisal. The State Oil Company of Azerbaijan Republic (SOCAR) drilled 8 appraisal wells from 1982 . 1991 within the PSA boundary.

AIOC has drilled a total of 5 appraisal wells and 4 sidetracks to date. In addition, the Chirag sector of the field has 15 development wells and has been on production since 1997. Chirag is currently producing ~ 125,000 bopd.



ESIAs have been carried out for each of the three phases in the development of the ACG field. A key element of the process was interaction with the engineering design team with the objective of removing, or at a minimum reducing, as many of the potentially significant environmental impacts as practicable, while enhancing positive benefits of the project wherever possible.

This has been achieved by assessing a wide range of options against numerous criteria including environmental and social impact, safety, technical feasibility, cost, ability to meet project needs, and stakeholder concerns. A critical element of the ESIA process has been the public consultation and disclosure programme carried out with a wide range of stakeholders.

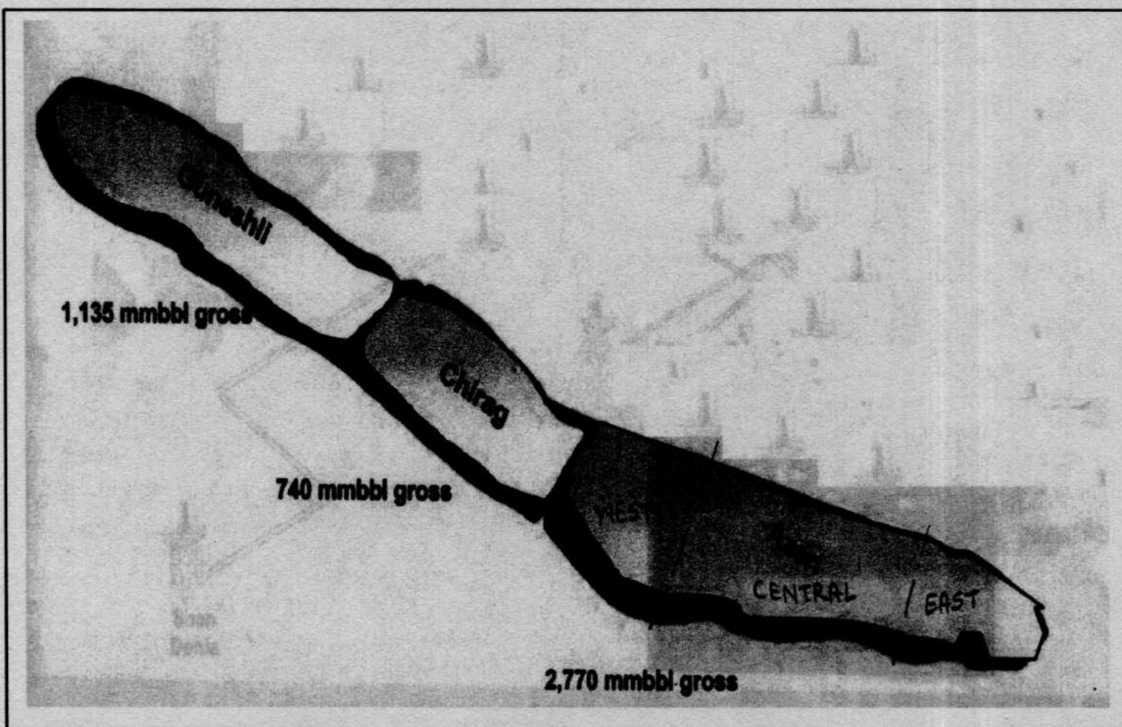
Following completion of the assessments, Environmental Statements were then submitted to Azerbaijan's Ministry of the Environment and Natural Resources in order to seek approval for the projects. The assessments have also been carried out to meet international finance institution standards.

For the Phase 1 development of the ACG field and Environmental and Social Action Plan has been prepared for both the construction and operations phase. This plan details the social and environmental management philosophy for the project, as well as plans for community and environmental investment, and construction planning, implementation and audit.

Azerbaijan, as one of the leading oil producing nations in the world at the turn of the 20th century is, once again, becoming an important oil producer and exporter at the beginning of the 21st century.

The modern phase of the development of Azerbaijan's hydrocarbon resources began in the early 1990s when the Azerbaijan Government launched a national strategy to stimulate the development of its significant oil reserves. The new policy commenced with the signing in 1994 of the 'Contract of the Century' – a Production Sharing Agreement awarded to the BP-led Azerbaijan International Operating Company for the development of the Azeri-Chirag-deepwater Gunashli (ACG) field.

Oil production from the ACG field commenced in 1997 through an 'early oil project' to achieve early export from the Chirag-1 platform. The full field development of ACG was sanctioned by project partners in 2004 and is expected to take production from the field up to around one million barrels a day by 2009.



On September 20, 2004, the 10th anniversary on the Agreement on the Joint Development and Production Sharing for the Azeri and Chirag Fields and Deep Water Portion of the Gunashli Field in the Azerbaijan Sector of the Caspian Sea signed between the State Oil Company of the Azerbaijan Republic and 10 well-known foreign oil companies representing six countries will be celebrated. September 20, 1994 was an important historical day in the development of Azerbaijan.

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By signing for the first time such a large-scale agreement with major western oil companies, independent Azerbaijan established grounds for international cooperation in the Caspian Sea, made it possible to attract more foreign investors to Azerbaijan and provided an impetus for signing oil and gas contracts.

Today, the activities jointly fulfilled within the frameworks of the signed 23 international oil agreements have created great possibilities for Azerbaijan. The activities have brought up-to-date technology to Azerbaijan, reorganized the infrastructure of the oil industry, developed transportation and service areas, trained qualified, professional national personnel and opened thousands of work places.

Over past years, the implementation of "The Contract of the Century" has provided $9bln in investment to the oil industry alone in Azerbaijan. This is a significant achievement reflecting the successful fulfillment of oil production at the Chirag-1 Platform. Significant activities were conducted under the "Early oil" project on the Azeri-Chirag-Gunashli fields. Accordingly, the underwater pipelines and a new modern terminal complex were constructed in Sangachal to transport the early oil and gas onshore.

A number of activities under the program have been conducted including seismic studies, surveys to find locations for platforms, underwater pipelines and pipeline construction, environmental surveys and ecological conditions and other activities. The completion of refurbishment activities for the Dada Gorgud semi-submersible drilling rig and subsequent ceremony sending the rig into operation on August 24, 1996 were also historical events.

A significant part of the new oil strategy was the expedition of exploration and drilling activities for oil and gas in the deep-water areas of the Azerbaijan sector of the Caspian Sea.

The Phase-1 project was directed at the central part of the contract area and covered the construction and installation of a 48-wellhead Production, Drilling and Quarters platform, the construction, installation of an adjacent gas-compressor and water injection platform, expanding the Sangachal Terminal and the pipeline from the platform to Sangachal. .

The development of the Azeri field was completed with the construction of the West and East Platforms. After the successful completion of the first four predrilling wells in the East Azeri, pre-drilling activities started in West Azeri.

The third stage (Phase-3) of the full-field development of the Azeri-Chirag-Gunashli fields covers the development of the deep-water portion of the Gunashli field and resources in the western part of the Azeri field and is considered to be the last development stage.

Sanctioning of the Phase-3 project was expected in September of 2004. According to the planned work program, the development of the Phase-3 project, in general, facilitated the production of more than 1 mln barrels (50mln tons per year)of oil from the Azeri-Chirag-Gunashli fields. The terminal constructed in Sangachal is one of the largest terminals in the world of its type.

Operations at the ACG field started in November 1997 with the start-up of production from the Chirag-1 platform. The platform has operated efficiently since that time, with average production during 2005 of around 140,000 barrels a day. As of the end of 2005 some 250 people were employed at the platform, of which 85% were Azeri nationals. By the end of 2005 total cumulative production from the field was 326 million barrels.

Operations commenced at the Central Azeri platform following the achievement of first oil in February 2005. As of the end of 2005 the production rate from eight pre-drilled wells at the platform was approximately 240,000 barrels per day.

Throughout operations, safety and security of people and operational facilities is paramount. Basic challenge for BP Operator Company as an organization continues to be to develop an effective safety culture.

BP operate an ISO 14001 certified environmental management system within the Azerbaijan business as an integral part of everyday operations. This process demands continual improvement of environmental performance through the minimization of operational impacts.

1.2<u>Brief well and reservoir overview for ACG field</u>

The trap, which forms the giant ACG Oil Field is a NW-SE trending, steeply dipping thrusted anticline. Within structural closure there are a number ofcrestal faults oriented along strike as well as mud volcanoes of varying size which complicate the otherwise straight forward structural geometry. Hydrocarbons are found within several different stratigraphic intervals within the Pliocene, the most important reservoirs occur in the Pereriv and overlying Balakhany Formations.

The extensive oil column that characterizes the field is the result of high structural relief combined with excellent top and lateral seals, for example, 900m on the north flank of Azeri and 580m on the south of Chirag.

Differing pressure regimes combined with effective seals may be responsible for the greater than 300 m north-south changes in oil contact(s). At the main Pereriv reservoir level, the ACG Field is 50km in length and 5km in width. Hydrocarbons are thought to have been sourced and migrated from Late Miocene to Early Pliocene aged Maykop lacustrine shales buried in the deep and rapidly subsiding South Caspian basin to the south of ACG.

The ACG structure formed in the Late Pliocene in response to compression associated with the formation of the Alpine/Himalayan mountain belts to the south. Release of overpressure from deeply buried shales exploited lines of weakness associated with the inversion and faulting forming the numerous mud volcanoes some of which are still active today.

1.1 Geological and Field Development Characteristics of ACG Oilfields

The Pereriv Formation forms the main ACG reservoir and is subdivided into 5 units,A to E. The Pereriv B and D sands are the most significant producing intervals. Secondary reservoirs are found both beneath (NKP, PK, Kalinsk) and above (Balakhany, Sabunchi, Surakhany) the Pereriv. The Balakhany is subdivided from V through X with the Balakhany VIII and X the most significant.

The main ACG reservoirs were deposited in a range of environments associated with a large river-dominated lacustrine delta. A dominant palaeoflow direction of NNW to SSE has been interpreted (160~).

Pereriv reservoirs are laterally extensive and vary little in thickness reflecting sand-rich depositional systems and low relief palaeo-topography. Laterally persistent lacustrine shales separate the Pereriv into five separate reservoirs and records the interplay between lacustrine expansion across a low-relief floodplain and fluvial deposition. The Pereriv and Balakhany sediments record sand-prone and shale-prone stacking patterns associated with alternation between more proximal and distal environments of deposition.

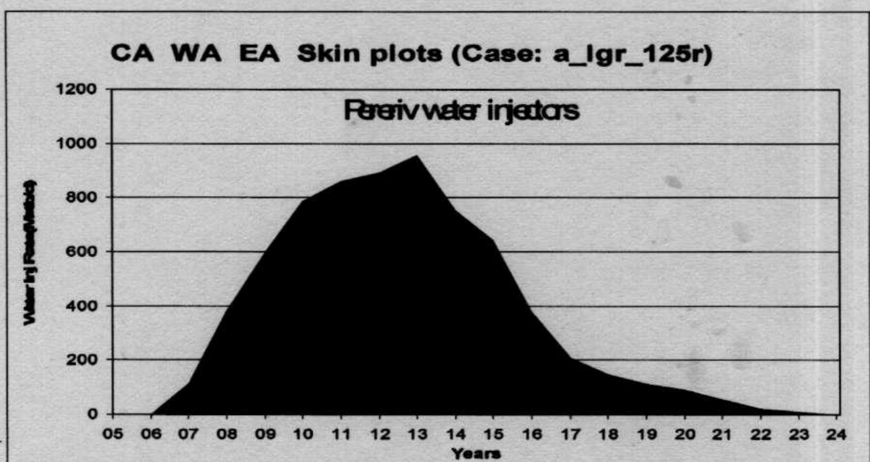
Delta plain facies are more sand-rich and have better connectivity than delta front facies. The cyclicity records delta advance and retreat related to climate changes in the palaeo-Volga system producing variations in lake level

Rate: field/platform and well requirements

Target rates

Field: 1000mbd

Well: 50mbd



2. DETAILED STUDY OF INJECTION PERFORMANCE

2.1Waterflood patterns

Waterflooding may be classified into peripheral or a pattern waterflood.The classification is based on the configuration of the injectors and producers.

Peripheral waterflood.

The injectors in a peripheral waterflood are at the edge or periphery of the reservoir. The advantages of using a peripheral waterflood are several. It usually has better areal sweep efficiency than pattern waterflood.When the injectors are located at the lowest structural portion of the reservoir, the gravity segregation affect can be fully utilized to increase the displacement efficiency. For a partially water drive reservoirs, the edge wells are logical choice for conversion to water injection wells. One of the major disadvantages is the response to water injection is limited to producers near the injection wells. The majority of the producers away from the injectors will not respond to the water injection quickly. For this reason the peripheral waterflood is used in relatively smaller reservoirs or used in combination with pattern waterflood.

Pattern waterflood.

The pattern waterflood may be divided into two types; irregular pattern and regular repeating patterns. In reality, perfectly repeatable patterns are seldom used. For technical or legal reason many fields were waterflood using irregular patterns. It is difficult to evaluate the recovery efficiency and monitor the progress of an irregular pattern waterflood. It is also difficult to asses the current status of the reservoir for enhanced oil recovery considerations. Therefore, except for a relatively small reservoir or under certain strenuous circumstances, repeatable waterflood patterns should be considered for waterflood projects.

The repeatable flood patterns may be classified into line drive, 4-spot, 5-spot, 7-spot, and 9 spot patterns. The choice of the flood pattern for a particular reservoir would be dependent on many technical, legal, process, and economic constraints.

Injector/Producer Ratio and well spacing.

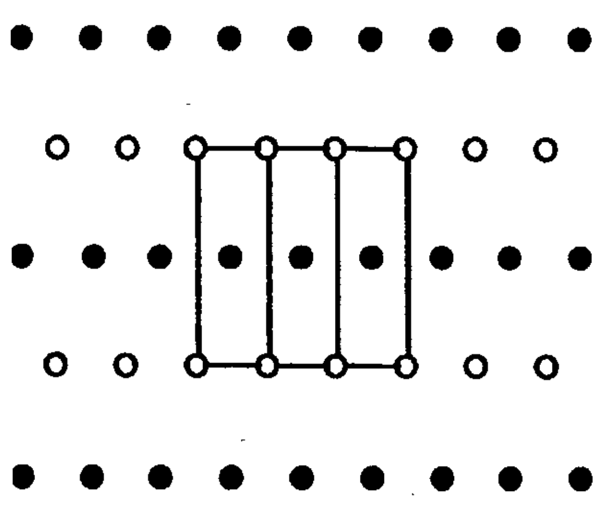
We need to be familiar with the injector/producer ratio of each flood pattern and the definition of well spacing. Figure below shows the direct-line drive and the staggered line drive. In the direct line drive patterns, the injectors in a row are facing the producers one - to – one on the other row. The injector producer ratio is 1/1 with two wells in basic repeatable unit. Since the well spacing is defined as the area per well regardless the well is an injector or a producer, the well spacing of a direct line drive pattern is the unit area divided by 2. I the staggered-line drive pattern is superior. Most of the line drive water floods are staggered-line drives.

Figures below shows different patterns. The inverted 4-spot pattern is the one with injector located at the center of the basic unit. For the regular 4-spot pattern the injector/producer ratio a total of 1 and ½ wells basic unit. The injector/producer ratio for inverted 4-spot is the inverse of the regular pattern. The 4-spot pattern is equivalent to the 7-spot pattern.

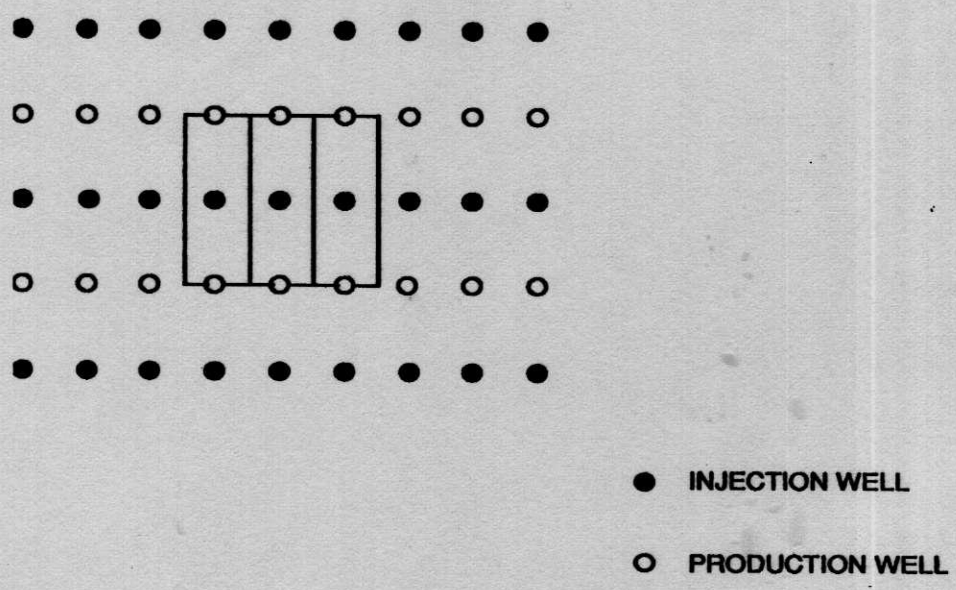
The 5-spot patterns may be interpreted as modified staggered-line drive patterns. The only difference is the ratio of the distance between similar wells and the distance between different wells. For perfectly repeatable 5-spot patterns there is no difference between regular 5-spot and inverted 5-spot patterns. The classification is meaningful for a restricted 5-spot or a small group of 5-spot patterns. The 5-spot pattern is the most widely used in waterfloods.

For the regular 9-spot pattern the injector/producer ratio is 3 to 1 with 4 wells per unit pattern. The 9-spot patterns are occasionally used in waterfloods.

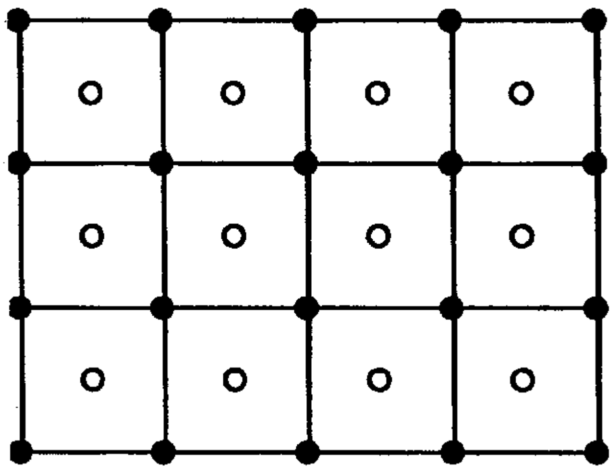
STAGGERED LINE DRIVE PATTERN



DIRECT LINE DRIVE PATTERN



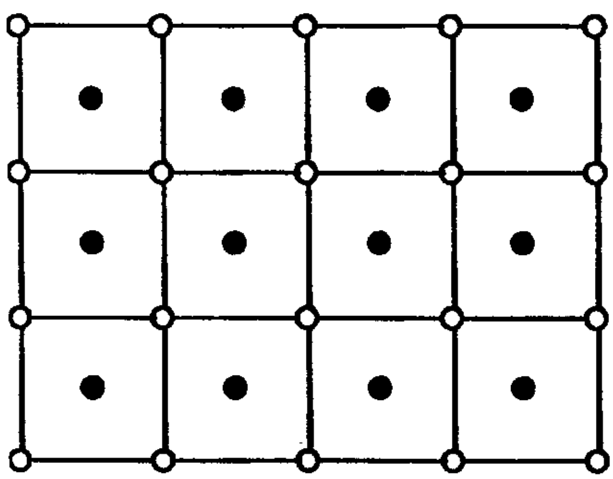
REGULAR FIVE-SPOT PATTERN



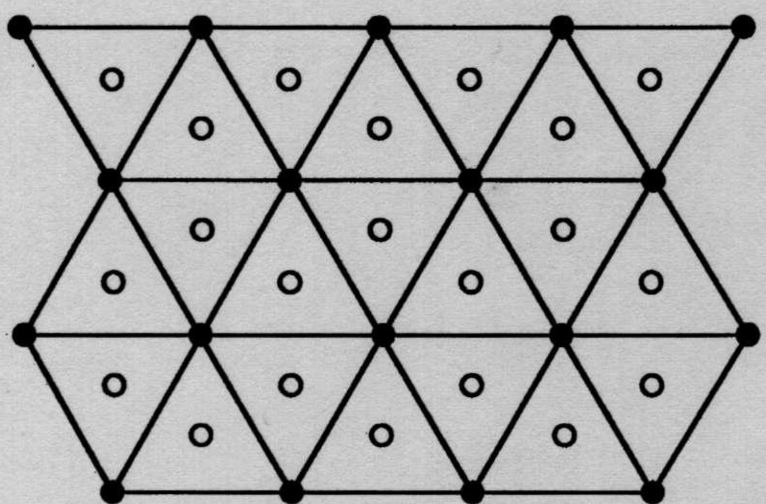
● INJECTION WELL

○ PRODUCTION WELL

INVERTED FIVE-SPOT PATTERN



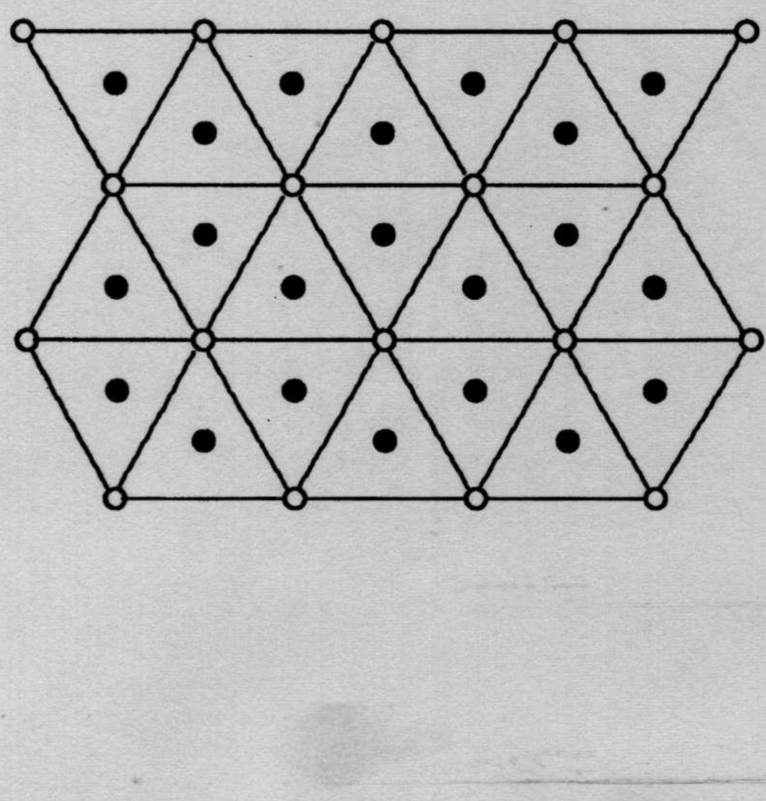
REGULAR FOUR-SPOT PATTERN



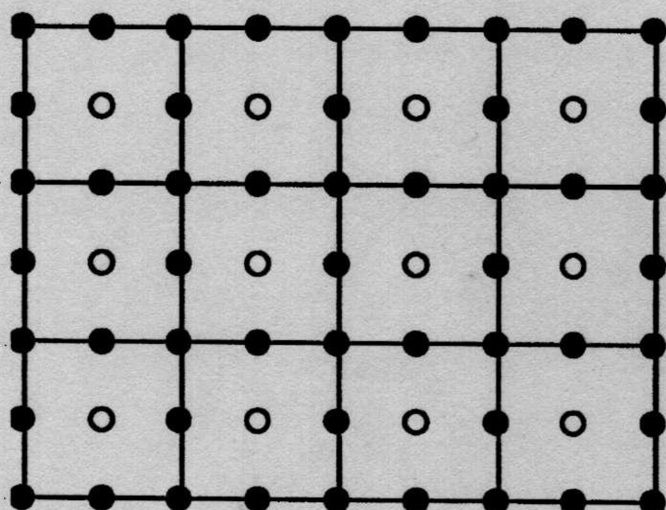
● INJECTION WELL

○ PRODUCTION WELL

INVERTED FOUR-SPOT PATTERN



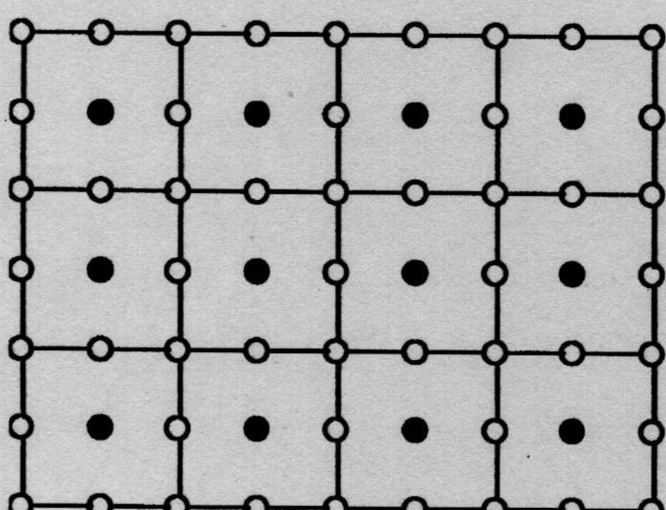
REGULAR NINE-SPOT PATTERN



● INJECTION WELL

○ PRODUCTION WELL

INVERTED NINE-SPOT PATTERN



Applications.

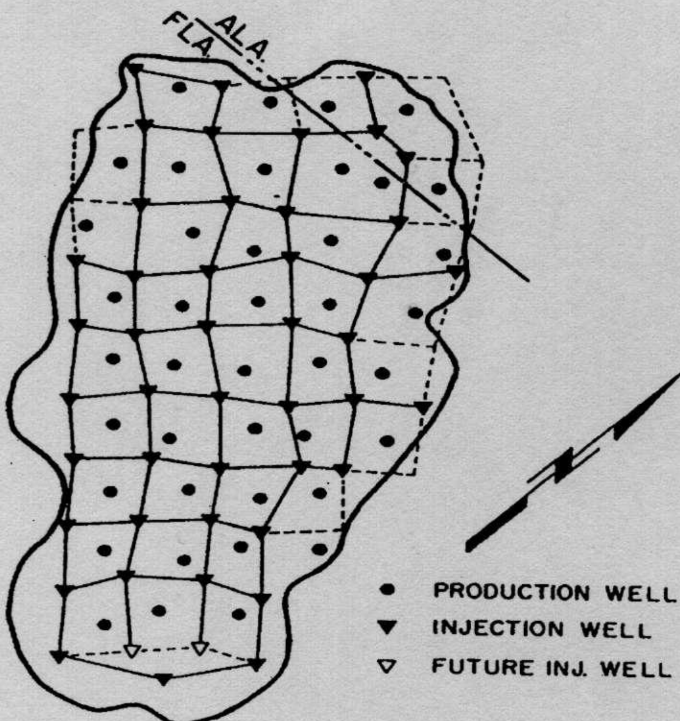
Many factors need to be considered in the selection of a flood pattern for waterflood project. These factor include physical, legal, process, and economic constraints. From the technical and process stand point, the most important factors are injection rate, response time, production rate, and the mobility ratio.

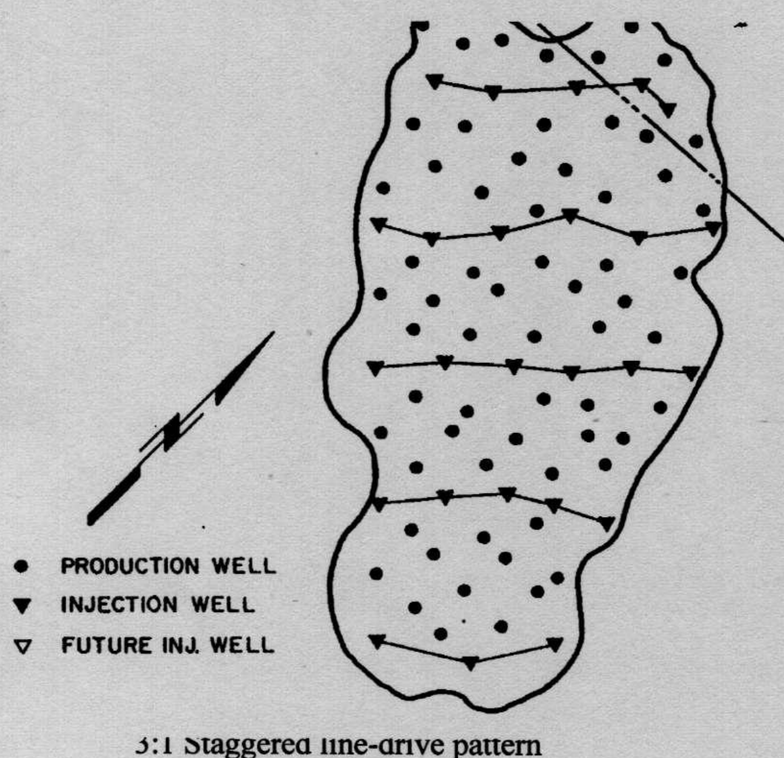
In most field applications, a combination of flood patterns has been used. An example of waterflood patterns selection study was reported by Shirer et al2. An example of this type of waterflood patterns are shown in the picture below. A 2 dimensional areal reservoir model was used in evaluating the performance of the waterflood patterns. The waterflood patterns evaluated includes a peripheral pattern, 5-spot pattern, a 3:1 line drive pattern, and a combination of peripheral and 5-spot patterns.

The result of the study indicated that the peripheral waterflood was inefficient due to stratification around the edges of the reservoirs. The result also showed that the production rate in the thick central section of the reservoir would decrease rapidly due to insufficient pressure support from the peripheral water injection.

The 3:1 staggered-line drive pattern was selected based on the oil recovery efficiency and economic return. Other factors considered in the selection included reservoir control, unitization delay, initial water production rate, and flexibility for conversation to other patterns.

Five-Spot Pattern





3:1 Staggered line-drive pattern

2.2. Waterflood sweep efficiency

Recovery efficiency.

Recovery efficiency is the fraction of oil in place that can be economically recovered with a given process. The efficiency of primary recovery mechanisms will vary widely from reservoir to reservoir, but the efficiencies are normally greatest with water drive, intermediate with gas cap drive, and least with solution gas drive. Results obtained with waterflooding have also varied. The waterflood recovery can range from less than the primary recovery to as much as 2.5 times the recovery obtained in some solution-gas drive reservoirs. Generally, primary and ultimate recoveries from carbonate reservoirs tend to be lower than from sandstones. Solution-gas-drive reservoirs will generally have higher oil saturations after primary recovery, and are usually the better candidates for waterflooding.

Overall waterflood recovery efficiency is given by

$$Erwf = Ed \times Ev$$

Where:

Erwf = Overall waterflooding recovery efficiency, fraction

Ed = Displacement efficiency within the volume swept by water, fraction

Ev = Volumetric sweep efficiency, fraction of the reservoir volume actually swept by water.

Displacement of oil by waterflooding is controlled by fluid viscosities, oil-water relative permeabilities, nature of the reservoir rock, reservoir heterogeneity, distribution of pore sizes, fluid saturations (especially the amount of oil present), capillary pressure, and the location of the injection wells in relation to the production wells. These factors contribute to the overall process efficiency. Oil recovery efficiency (ER) of a waterflood is the product of displacement efficiency (ED) and volumetric efficiency (Ey), both of which can be correlated with fluid mobilities:

ER = E0Ey = E0EpEi

Where

ER = overall reservoir recovery or volume of hydrocarbons recovered divided by volume of hydrocarbons in place at start of project

E0 = volume of hydrocarbons (oil or gas) displaced from individual pores or small groups of pores divided by the volume of hydrocarbons in the same pores just prior to displacement.

Ep = pattern sweep efficiency (developed from areal efficiency by proper weighting for variations in net pay thickness, porosity, and
hydrocarbon saturation): hydrocarbon pore space enclosed behind the injected-fluid front divided by total hydrocarbon pore space of the
reservoir or project.

Ei = hydrocarbon pore space invaded (affected, contacted) by the injection fluid or heat front divided by the hydrocarbon pore space
enclosed in all layers behind the injected fluid

Volumetric sweep efficiency

Whereas displacement efficiency considers a linear displacement in a unit segment (group of pores) of the reservoir, macroscopic or volumetric sweep takes into account that fluid (i.e., water) is injected at one point in a reservoir and that other fluids (i.e., oil, water) are produced from another point. Volumetric sweep efficiency, the percentage of the total reservoir contacted by the injected fluid(often called fluid conformance), is composed of areal (or pattern) efficiency and vertical sweep.

Volumetric sweep efficiency is defined by:

Ev = Ea x Ei

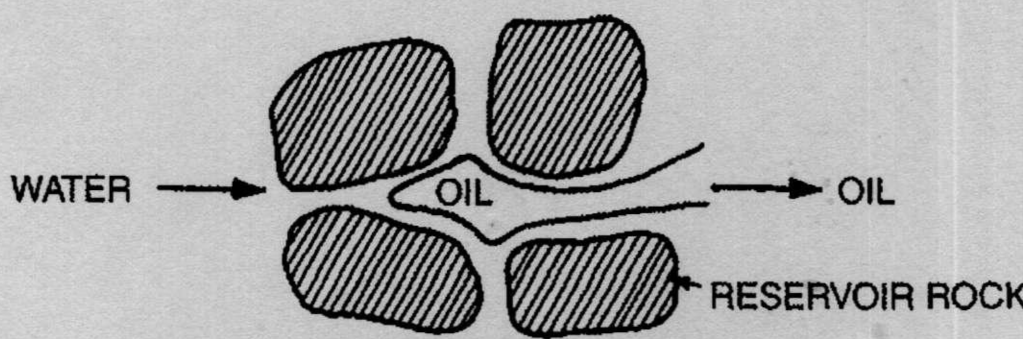
Where:

Ea = Areal sweep efficiency

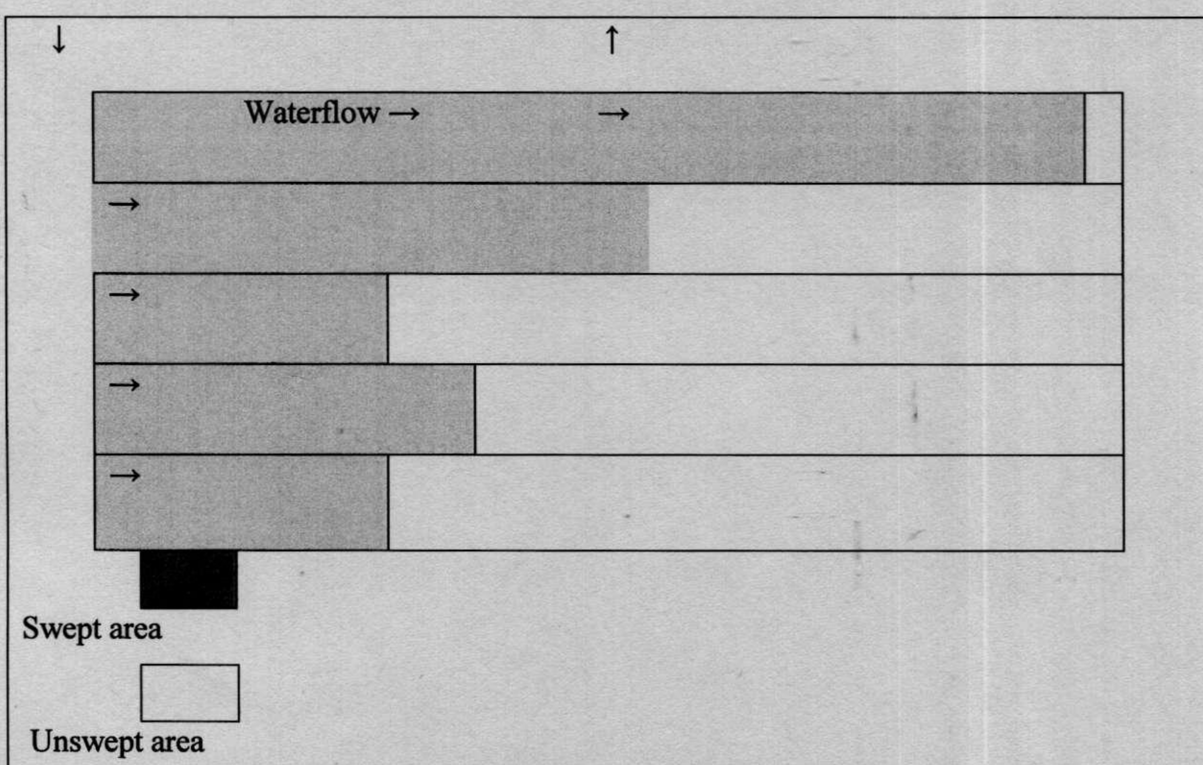
Ei = Vertical sweep efficiency

Sweep efficiency is related to permeability variations, fluid properties, fluid distribution fluid saturation and fracture systems. Adverse permeability variations result in poor sweep efficiency, rapid water breakthrough, and high water production. Factors affecting sweep efficiencies are shown in Table below.

Table shows a zone of high permeability at the top of a formation. Water, which follows the path of the least resistance, preferentially enters this zone. The result is early breakthrough and substantial amount of oil remaining in the reservoir due to poor vertical sweep efficiency.



MICROSCOPIC SWEEP



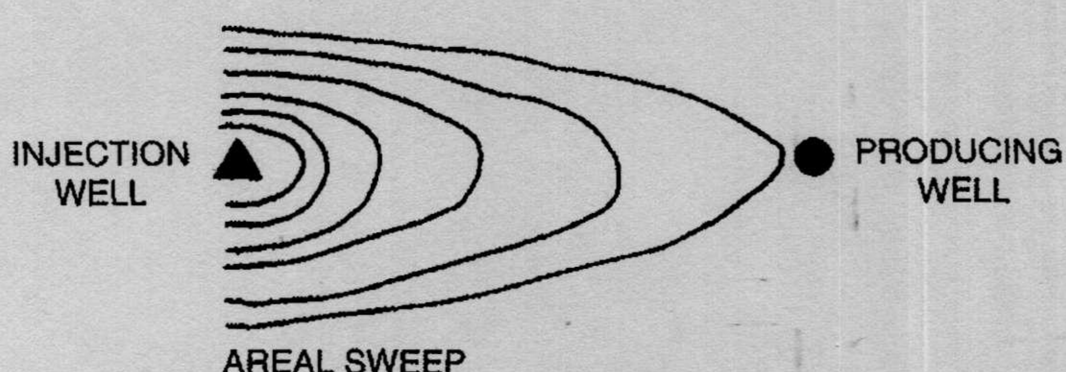
Displacement sweep efficiency

Factors affecting the displacement efficiency for any oil recovery process are pore geometry, wettability (waterwet, oil-wet, or intermediate), distribution of fluids in the reservoir, and the history of how the saturation occurred.

Results are displayed in the relative permeability curves from which the flowing water saturation (or conversely the oil saturation) can be obtained at any total fluid saturation. As shown in Figure above displacement efficiencies decrease as oil viscosities increase.

Areal or pattern sweep efficiency.

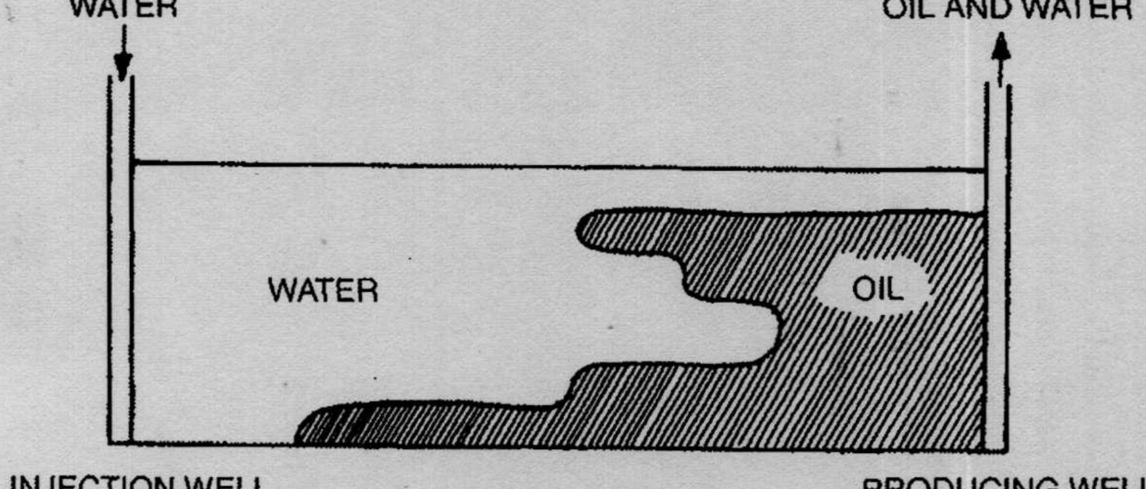
Areal sweep efficiency of an oil recovery process depends primarily on two factors: the flooding pattern and the mobilities of the fluids in the reservoir. Areal sweep efficiency is more important for considering rate vs. time behaviour of a waterflood rather than ultimate recovery because, at the economic limit. Most of the interval flooded has either had enough water throughout to provide 100% areal sweep or the water bank has not yet reached the producing well so that no correction is needed for areal sweep.



Vertical or Invasion Sweep Efficiency.

For well-ordered sandstone reservoirs, the permeability measured parallel to the bedding planes of stratified rocks is generally larger than the vertical permeability. For carbonate reservoirs, permeability (and porosity) may have developed after the deposition and consolidation of the formation; thus the concept of a stratified reservoir may not be valid.

However, in stratified rocks, vertical sweep efficiency takes into account the inherent vertical permeability variations in the reservoir. Vertical sweep efficiency of a waterflood depends primarily upon the vertical distribution of permeabilities within the reservoir, on the mobility of fluids involved, and on the density differences between flowing fluids. As a result of no uniformity of permeabilities in the vertical direction, fluid injected into an oil-bearing formation will seek the paths of least resistance and will move through the reservoir as an irregular front. Consequently, the injected fluid will travel more rapidly in the more permeable zones and will travel less rapidly in the tighter zones. With continued injection, and displacement of some of the resident fluids, the saturation of the injected fluid will become greater in the more permeable areas than in the low-permeability strata. This can cause early breakthrough of injected fluid into the producing wells before the bulk of the reservoir has been contacted. In addition, as the saturation of the injected fluid increases in the highly permeable zones, the relative permeability to that fluid also increases. All of these effects can lead to channelling of the injected fluid, which is aggravated by the unfavourable viscosity ratio common in waterflooding. In many cases, permeability stratification has a dominant effect on behaviour of the waterflood.



VERTICAL SWEEP

Bypassed Oil.

In determining water flood efficiency, we need to calculate the effect of oil migration from the flooded zones in a reservoir to areas with little or no water. Calculating these requires data on the reservoir volume, pressure and production history.

Recompletion opportunities should be evaluated with an eye toward preventing or recovering trapped oil, and maximizing sweep efficiencies in future operations. These recompletions may involve deepening and/or perforating additional intervals to expose more of the oil zone, or plugging back to reduce excessive water production.

For example, in producing wells that offset, or adjacent to injectors, some challenging of injected water may occur, resulting in high water cuts. Injection profile work, followed by use of plugging material(and in same cases, selectively plugging back producing well) may alleviate the problem.

If the differences between reservoir properties in adjacent zones are substantial(i.e,. one zone is much more permeable than other), we may be able to minimize excessive water challenging and reduce the amount of bypassed oil by flooding the zones separately provided they do not vertically communicate with each other. If this approach is economically unattractive, or if the zonal properties variations are minimal, it is common to practice to correlate logs(e.g., the gamma ray and neutron logs in cased hole) for the injection well with the offset wells, and perforate and/or fracture the wells accordingly.

3. Important Factors in Waterflooding or Water-Injection Pressure Maintenance

In determining the suitability of a given reservoir for waterflooding or pressure maintenance, these factors must be considered: (1) reservoir geometry, (2) lithology, (3) reservoir depth. (4) porosity. (5) permeability (magnitude and degree of variation), (6) continuity of reservoir rock properties, (7) magnitude and distribution of fluid saturations, (8) fluid properties and relative-permeability relationships, and (9) optimal time to walerflood.

Generally, the influence of all these factors on ultimate recovery, rate of return, and ultimate economic return must be considered collectively to evaluate the economic feasibility of conducting waterflood and/or water-pressure-maintenance operations in a particular reservoir. Factors other than reservoir characteristics also will have a great influence. These include the price of oil, marketing conditions, operating expenses, and availability of water.

Reservoir Geometry

One of the first steps in organizing reservoir information to determine whether water injection is feasible is to establish the geometry of the reservoir. The structure and stratigraphy of the reservoir control the location of the wells and, to a large extent, dictate the methods by which a reservoir may be produced through water-injection practices.

Structure is a principal factor in governing gravitational segregation. In the presence of high permeabilities, recovery by gravity segregation, particularly in old pools, may reduce oil saturation to a value at which the application of water injection may be uneconomical. If a suitable structure exists and the remaining oil saturation proves sufficient for secondary operations, the adaptation of a peripheral flood may result in a higher areal sweep efficiency than would the conventional pattern or linedrive floods. High relief also would suggest investigation of a companion gas-injection program. The shape of the field and the presence or absence of a gas cap would also influence this decision.

Most water-injection operations conducted to date have taken place in fields that exhibit only moderate structural relief. Many floods are located in pools where the oil accumulation occurs in reservoirs of the stratigraphic-lrap type. Since these pools, as a rule, have been produced by dissolved-gas drive and have not received any benefits from natural-water encroachment or other displacement-energy mechanisms, high oil saturations usually remain after primary-recovery operations, making these reservoirs most attractive for secondary-recovery operations.

In such pools, the dip of the strata may be so slight as to have no noticeable effect on secondary-recovery operations. Thus, the location of the injection and producing wells may be made to conform to properly lines and to known sand conditions. Whether such a practice would prove successful in pools where oil and gas distribution has been conirolled by a high-relief structure is questionable.

An analysis of reservoir geometry and past reservoir performance is often important in defining the presence mid strength of a natural-water drive and. thus, in defining the need for supplementing injection. II u nalural-waler drive is determined to be strong, injection may be unnecessary. Structural features such as faults, or stratigraphic features such as shale-outs, or any other permeability barrier usually will influence these decisions. An otherwise suitable reservoir may be so highly faulted as to make any injection program economically unattractive.

Lithology

Lithology has a profound influence on the efficiency of water injection in a particular reservoir. Lithological factors that affect floodability are porosity, permeability, and clay content. In some complex reservoir systems, only a small portion of the total porosity, such as fracture porosity, will have sufficient permeability to be effective in water-injection operations. In these cases, a water-injection program will have only a minor impact on the matrix porosity, which might be crystalline, granular, or vugular in nature. Evaluation of such effects requires an extensive laboratory investigation and a somewhat comprehensive reservoir study. Evaluations can be supplemented by experimental pilot injection operations.

There is laboratory evidence that a difference between the mineralogical compositions of the sand grains and cementing material of various oil-producing formations may account for differences in the residual oil saturation (ROS) that have been observed subsequent to waterflooding. These differences in oil saturation are indicated to be dependent not only on the mineralogical composition of the reservoir rock but also on the composition of the hydrocarbons within the rock. Benner and Bartell[5] have shown that, under certain conditions, the basic constituents of some types of petroleum cause quartz to become hydrophobic because of the adsorption of these constituents by the surface of the sand grains. In a similar manner, the acidic constituents of other types of petroleum render calcite hydrophobic. At present, there are not enough data available to permit valid predictions regarding the effects on recovery when the pore walls are made wet to various degrees by water and petroleum, but it appears probable that there is some effect.

Although there is evidence that the clay minerals that are present in some oil sands may clog the pores by swelling and deflocculating when waterflooding is used, no exact data are available as to the extent to which this may occur. The effect depends on the nature of the clay minerals; however, an approximation of the pore-clogging impact may be determined through laboratory investigations. The montmorillonite group is most likely to cause a reduction in permeability by swelling; kaolinite is least likely to cause a reaction. The extent to which such a reduction in permeability will occur also depends on the salinity of the water that is injected Brines arc usually preferable to fresh water for flooding purposes.

Reservoir depth.

The depth of the reservoir is another factor that should be considered in watei flooding If the depth of the used as injection and producing wells, lower recoveries may be expected than in cases in new wells reservoir is too great to permit redrilling economically and if old wells have to be can be drilled. This is particularly true in old fields where regular well spacings were not observed and where infill development was not as extensive as lease-line development. Also, after primary operations, ROS`s in most deep pools probably are lower than in shallow pools, because a greater volume of solution gas was generally available to expel the oil and because shrinkage factors are higher. Therefore, less oil remains. Greater depth, on the other hand, permits the use of higher pressures and wider well spacings. provided the reservoir rock possesses a sufficient degree of lateral uniformity.Caution should be exercised in shallow-depth fields since the maximum pressure that can be applied in a secondary-recovery operation is limited by the depth of the reservoir. In waterflood operations, it has been found that there is a critical pressure (usually approximating that of the static pressure of the column of rock overlying the productive sand, or about 1 psi/ft of sand depth) which, if exceeded, apparently permits the penetrating water to expand openings along fractures or other planes of weakness, such as joints and, possibly, bedding planes. This results in the channeling of the injected water or the bypassing of large portions of the reservoir matrix. Consequently, an operational pressure gradient of 0.75 psi/ft of depth normally is allowed to provide a sufficient margin of safety to prevent pressure parting. However, to remove as much doubt as possible, information regarding fracture pressures or breakdown pressures in a given locality should be studied. Either pressure should be considered as an upper limit for injection. These considerations will also influence equipment selection and plant design, as well as the number and location of injection wells

Porosity

The total recovery of oil from a reservoir is a direct function of the porosity, because the porosity determines the amount of oil that is present for any given percent of oil saturation. Since the fluid content of reservoir rock varies from 775.8 to 1,551.6 bbl/acre-ft for porosities of 10 and 20%. respectively, it is important that reliable porosity data be assembled. Porosities sometimes vary from 10 to 35% in an individual zone. In limestones and dolomites, pinpoint and fractured porosities may vary from 2 to 11%; honeycombed and cavernous porosities may vary from 15 to 35%. In establishing an average porosity, the arithmetic average of the porosities determined from core samples has proved acceptable. If there are sufficient data, isoporosity maps are used when the distribution of porosity is important—as, for instance, when some fields are unitized. These maps may be areally or volumetrically weighted to give a very good total porosity value. If enough core data are available, statistical analyses of porosity and permeability may be used to improve the use of these data.

To date, the most satisfactory method of measuring this important property has been through laboratory measurements of core samples. Various logging methods have been quite satisfactory in many cases. The logs may include a "microlog" or "contact log," neutron log, density log. or sonic log.

Permeability (Magnitude and Degree of Variation)

The magnitude of the permeability of the reservoir rock controls, to a large degree, the rate can be sustained in an injection well for a specific pressure at the sandface. Therefore, in determining the suitability of a given reservoir for waterflooding. it is necessary to determine (I) the maximum permissible injection pressure from depth considerations, and (2) the rate vs. spacing relationships from the pressure/permeability data. This should indicate roughly the additional drilling that would be required to complete the proposed flood program in a reasonable length of time. An approximation of the expected recovery then can be compared with lhe monetary expenditure for this development program, so as to indicate quickly the suitability of the reservoir as a flood prospect. If the project profitability is favourable, more detailed work may be warranted.

The degree of variation in permeability has justifiably received much attention in recent years. Reasonably uniform permeability is essential for a successful waterflood, because this determines the quantities of injected water that must be handled. If great variations in the permeability of the individual strata within the reservoir are noted, and if these strata maintain continuity over substantial areas, injected water will break through early in high-permeability streaks and will transport large quantities of injected water before the low-permeability streaks have been swept effectively. This, of course, will influence the economics of the project and thus the suitability of the reservoir for flooding. Not to be overlooked is that continuity of these streaks or strata is as important as the permeability variation. If there is no correlation between the permeability profiles of the individual wells, the chances are good that the high-permeability zones are not continuous and that the channelling of injected fluids will be less severe than indicated by performance calculations.

Continuity of Reservoir-Rock Properties

The importance of reservoir-rock continuity in relation to permeability and vertical uniformity in determining the suitability of a reservoir for waterflooding has been mentioned previously. Since the flow of fluids in a reservoir is essentially in the direction of bedding planes, horizontal (along bedding planes) continuity is of primary interest. If the reservoir body is split into layers by partings of shale or dense rock, a study of across section of the producing horizon should indicate whether individual layers have a tendency to shale out in relatively short lateral distances, or whether sand development is uniform. Also, evidence of crossbedding and fracturing should be collected from core data. These features should be considered in determining well-spacing and flood patterns, and in estimating the volume of the reservoir that will be affected during the injection program. The presence of shale partings is not necessarily detrimental, provided the individual layers of reservoir rock exhibit a reasonable degree of continuity and uniformity with respect to permeability, porosity, and oil saturation. When vertical discontinuities exist (i.e.. when there is a water- or gas-bearing stratum in the producing formation), shale partings will sometimes permit a selective completion; such a completion allows the exclusion or reduction of water or gas production and permits selective water injection.

<u>Fluid Properties and Relative-Permeability Relationships</u>

The physical properties of the reservoir fluids also have pronounced effects on the advisability of waterflooding a given reservoir. Of major importance among these effects is the viscosity of the oil. The viscosity of the oil affects the mobility ratio. The relative permeability of the reservoir rock to the displacing and displaced fluids is also a factor in the mobility ratio, as is the viscosity of the displacing fluid—water, in ihis case (refer to Chap. 43) The mobility of any single phase (e.g.. oil) is the ratio of the permeability of that phase lo its viscosity. k_o/*fj*.,, The mobility ratio, *M*, is the ratio of the mobility of the displacing fluid to that of the displaced fluid. The largci the mobility ratio, the lower will be recovery at break-through; hence, more water must be produced to recover a fixed amount of oil. This is because (1) a smaller area is swept at breakthrough, and (2) the stratification effect is enhanced.

With high-viscosity (low-gravity) crudes, primary recovery normally is lower and shrinkage is less than with low-viscosity crudes. This tends to offset the bad effects of high-viscosity crudes since it often results in higher oil saturations at the beginning of water-injection operations.

3.1***Optimal Time to Waterflood***

The optimal time to waterflood a particular reservoir depends on the operator's primary objective in water-flooding. Among these objectives might be (1) maximum oil recovery. (2) maximum number of dollars of future net income, (3) maximum number of dollars of future net income per dollar invested, (4) stabilized rate of monetary return, or (5) maximum discounted present worth. Certainly all these objectives are desirable, and all seem to call for an early beginning of water-injection operations; however, that is not always the case. The most common way to determine the optimal time to begin flooding is to compute the anticipated oil recovery, production rate, monetary investment, and income for several assumed times of initiation—and then observe the effect of these factors on the most desirable goal,

In a homogeneous reservoir, maximum oil recovery can be expected if flooding is begun at the precise time bubble-point pressure is reached. This is because residual oil after waterflooding will have the maximum amount of gas in solution and. at the bubble point, oil viscosity is most favourable. If the effect of a free-gas saturation on ROS is ignored, heterogeneity causes the optimal pressure for highest recovery to be lower than the bubble point pressure. If the bubblepoint pressure is quite low, production rates may have substantially declined and the operator may prefer an earlier flood. Water-injection operations initiated above the bubblepoint in a heterogeneous recovery may ultimately result in less oil recovery but may be justified economically.

Objective 1, maximum oil recovery, is important to all operators or agencies who are concerned primarily with the best interests of the public. Objectives 2,3, and 5, involving certain financial goals, are most important to privately owned companies, either independent or major; in these cases, the choice would depend on a company's size and financial position and on whether it is planning to sell the property. Objective 4, stabilized rate of monetary return, becomes important when financing, such as production loans and oil payments, and federal taxes are considered. This last point, federal taxes, is particularly important to small operators who are subject to large variations in a tax rate that depends on their tax bracket. Also, some money-lending agencies are particularly interested in properties that are anticipated to have long producing lives - i.e., to have a production rale that has been .stabilized somewhat below the attainable rate. Other agencies aie more inlercstcd in a fast return on investment.

In summary, then, the optimal time to begin water-injection operations depends on which of ihe objectives is of primary concern.

4. Water injection rate calculation.

Basic Concept

Water injection rate is a critical parameter in a waterflood design. Since the oil production rate is a function of water injection rate, the water injection rate must be maintained at a level that would make the waterflood project profitable.

The water injection rate can be affected by a host of reservoir and process parameter such as injection profile, vertical saturation distribution, effective permeabilities, viscosity contrast, pressure pattern, pattern size, etc. To obtain a water injection rate estimates, many assumptions have to be made to develop water injection rate models.

Several methods may be used to estimate the water injection rate. These methods include steady state and unsteady state water injection rate equations developed under assumed reservoir and process conditions.

Most of these equations are useful in providing a first approximation of the water injection rate. The water injection rate estimated from the equations needs confirmation from a field injection test. In the filed is accessible, an injection test should be conducted to gain a more realistic water injection rate estimate. Where a hydraulic fracturing is required to improve the injection rate, an injection test is necessary to determine the injection rate.

In most waterflood projects the reservoirs is depleted to the extent that a free gas exists at the start of water injection. The presence of a free gas phase will dramatically affect the water injection rate. The water injected into the reservoir during the injection test may react with the clay minerals in the reservoir causing clay swelling that could significantly reduce the water injectivity. Further, the injection water may carry suspended solids and impurities that may cause plugging of the injection sandface to reduce the water injectivity.

Steady State Methods

Darcy's Radial Flow Equation:

The simplest equation for estimation the water injection rate is Darcy's radial flow equation.

$$i_w = \frac{0.00708 h k_o \Delta P}{\mu_o \ln (r_e/r_w)}$$

i_w = injection rate, RBL/D

h = thickness, ft

k_w = effective permeability, md

ΔP = pressure differential, psi

μ_w = viscosity, cp

r_e = external radius, ft

r_w = wellbore radius, ft

The reservoir data and process parameters required for water injection rate calculation are reservoir thickness, effective permeability to water, pressure differential, water viscosity, wellbore radius, and external radius of the injection system. Since the reservoir has both oil and water phases in place, the use of water properties in the calculation may give an optimistic water injection rate, therefore, oil properties may be used to calculate the water injection rate to give a range of water injection rate estimates.

Pattern Injection for Unit Mobility Ratio Case

The water injection rate of an injector is often influenced by the activity of its adjacent injectors and producers. Pattern the water injection rate equations have been developed by Muskat for line drives and 5 spot patterns under the major assumption that the mobility ratio is one (Fig. 5-3).

The equation is often used to provide a base injection rate which can be adjusted to estimate the injection rate for the cases where the mobility ratio is not equal to one. The adjustment of the base injection rate is made based on laboratory test data which take into account the effect of the mobility ratio and the increasing areal sweep efficiency.

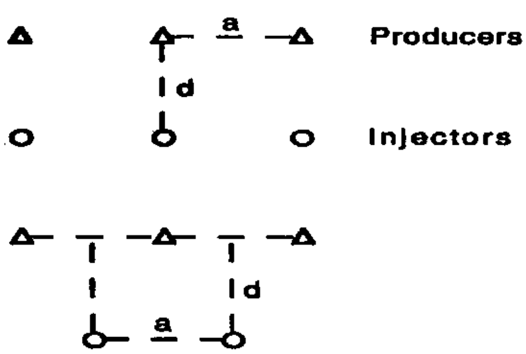
Direct line Drive $\left(\frac{d}{a} \geq 1\right)$

$$i_w = \frac{0.001538\ k\ k_{ro}\ h\ \Delta p}{\mu_o\left(\log\frac{a}{r_w} + 0.628\frac{d}{a} - 0.902\right)}$$

Staggered Line Drive $\left(\frac{d}{a} \geq 1\right)$

$$i_w = \frac{0.001538\ k\ k_{ro}\ h\ \Delta p}{\mu_o\left(\log\frac{a}{r_w} + 0.628\frac{d}{a} - 0.902\right)}$$

Line Drive Patterns:



i = BBL/D
k = md.
h = ft.
ΔP = p.s.i.
μ_o = cp.
r_w = ft.
d = ft.
a = ft.

Unsteady State Methods

Muskat's Equation for Single Well Injection

Muskat developed single-well water injection rate equations using a piston like displacement concept. As water is injected into the reservoir, the oil if effectively displaced to form an oil bank ahead of the water front. The resistance in the oil bank and the resistance in the water zone are taken into account in the equations.

A set of equations were developed for the case when the oil bank effect on the injection rate is negligible. These equations provide the relationship between the injection rate and the injection time, and the relationship between the cumulative injection and the injection time. These equations are convenient for evaluating the injection rate as a function of injection time.

No interference
No oil bank effect

Field Units

iw = BBL/D	P = p.s.i.	
h = ft.	m = cp.	t = Days
kw = md.	r = ft.	

Water Injection Rate vs. Time:

$$[10^{(\frac{0.00617\, k_w\, h\, \Delta P}{\mu_w\, i_w})}] * (\frac{0.0142\, k_w\, h\, \Delta P}{\mu_w\, i_w} - 1) + 1 = \frac{0.0253\, k_w\, \Delta P\, t}{\mu_w\, \phi\, \phi_w\, r_w^2}$$

ϕ = Porosity
$\phi_w = 1 - S_{girr} - S_{or} - S_{wir}$

Cumulative water injected vs. Time :

$$\frac{W_i}{h\, \phi\, \phi_w}\left[\log\left(\frac{1.78\, W_i}{h\, \phi\, \phi_w\, r_w^2}\right) - 0.435\right] + 0.244\, r_w^2 = \frac{0.00617\, k_w\, (\Delta P)\, t}{\mu_w \phi\, \phi_w}$$

W_i = BBL

A set of equation was also developed for the case when the oil bank effect in the injection rate id not negligible. These equations require the end-point mobility ration which represents the relative effect of the oil bank and the water zone resistances on the injection rate. These equations provide the relationship between the injection rate and the cumulative injection, and the relationship between the cumulative injection and the injection time. From the two relationships, the water injection rate can be estimated at a particular injection time.

Multi-Well Injection Rate

Craig proposed a method to estimate the multi-well water injection rate . The approach used a conductance ratio to adjust the base injection rate calculated from a 5-spot water injection rate equation. The conductance ratio is defined as the ratio of water injection rate at any time to the initial water injection rate. It is formulated as a function of Craig's mobility ratio and areal sweep efficiency of a 5-spot pattern. The correlation of conductance ratio with respect to the mobility ratio and areal sweep efficiency is established from the laboratory tests.

Limitations.

The water injection rate equations discussed above do not include the effects of the formation damage and fractures. Neither do they consider the effects of reservoir heterogeneity such as vertical variation of horizontal permeabilities, areal distribution of formation thickness, directional permeability, etc. However, they are useful in providing an initial estimate of water injection rate which must be confirmed by a filed water injection test.

Water Injection Rate Estimates

Steady State:

Single phase Darcy's radial flow

Pattern flow assuming mobility ratio = 1

Unsteady State:

Single well injection (no interference)

With negligible oil bank effect

With oil bank effect

Multi-well injection (with interference)

Base injection rate

Conductance ratio

Numerical simulation

Water injectivity.

Water injectivity is defined as the injection rate per unit pressure difference between the bottom hole injection pressure and the reservoir pressure. . Injectivity test is carried out by injecting water into a well at varying rates while measuring bottom hole pressures. When injection rate is plotted against the bottom hole pressure, a break in the curve results at the parting of formation fracture pressure. The parting pressure gradient, normally 1psi/ft of the well depth, may vary from 0.75 to 1,2 psi/ft. Above the parting pressure water can be injected at higher rates per increment of pressure.

Note that the parting pressure is also a function of the reservoir pressure, and at flow reservoir pressures the formation can easily be fractured. A rule-of- thumb to follow is that for every 100 psi change in formation pressure, parting pressure changes by 60-70 psi.

It is very important to determine the required injection rate which controls the life of water flood project. Normally injection pressures are set slightly below the parting pressure. In same special cases, where formation permeabilities are very low and injectivity water is very clean, injection may be carried above the parting pressure. If this procedure is,followed, it is advisable to run injection profiles regularly to make sure water injection in zones of interest.

5. **Factor affecting flood performance**

Areal and vertical reservoir Heterogenety.

Areas of high and low permeability in a reservoir may cause an unbalanced flood performance. Cross bedding may also impair fluid movement between injection and production wells. Sometimes, a reservoir may contain planes of weakness or closed natural fractures that open at bottom hole injection pressures.

In addition of those factors, we must also consider the level of reservoir continuity between an injector/production well pair.

Reservoir pressure level.

Waterflooding results maximum oil recovery when the reservoir pressure level is at the original bubble point. At the original bubble point pressure, a barrel of stock tank oil represents the maximum amount of reservoir oil, thereby occupying the largest volume and consequently a high oil relative permeability. In addition, several other factors favor waterflooding at this pressure:

Reservoir oil viscosity is at its minimum value, which improves the mobility and areal sweep

Producing wells are at their highest productivity index

There is no delay in flood response, since the reservoir has no free gas saturation at this point.

Some people argue that optimum pressure level is slightly below the bubble point pressure because the presence of a small amount of gas saturation reduces the residual oil saturation to waterflood. However its difficult to practically achieve this condition uniformly throughout the reservoir. A large variation of gas saturation may occur and negatively affect the waterflood performance.

Fluid saturation, Distribution and properties.

One of the most important factors responsible for the success or failure of waterflood is the fluid saturation at the start of the flood. It is difficult to have an economic waterflood at water saturation of 50% or more. Under this high saturation conditions, the relative permeability of water has a adverse effect, making it difficult to form a oil bank.

However, it is possible to conduct a successful waterflood with connate water saturations as high as 50% or more, only if a favorable combination of other factors is present. In general, higher connate water saturations increase the risk involved in waterflooding.

The relative permeability characteristics of a reservoir rock are a measure of the rock's ability to conduct one fluid when one or more fluids are present. These flow properties are based on pore geometry, wettability, fluid distribution and saturation history. Figure below shows typical water/oil relative permeability characteristics for water-wet and oil-wet formations.

The water oil flow properties of reservoir rock are generally used to estimate the oil recovery we might obtain by flushing an oil-saturated rock with water. Information on relative permeability to water at floodout conditions provides water injectivity value.

Another important factor to consider in waterflood screening is the gas saturation at the start of the waterflood. The gas, which is liberated in the reservoir by pressure depletion, must be resaturated. If low sweep or displacement efficiencies occur during waterflood, a large proportion of the oil may resaturate portions of the unswept pore volume and not be produced. Reservoirs with high formation volume factors and a high solution gas/oil ratio should be flooded at, or slightly above, the bubble point where the viscosity is the minimum.

In the thick reservoirs with high horizontal and vertical permeability, fluids may be evenly distributed. In these cases, the top of the reservoir will contain high gas saturation, and the base of the sand will contain high oil saturation. Water injected in this type reservoir will tend to enter the formation having high gas saturation and will override (and often bypass) the oil. Similar problems may occur in reservoirs that are underlain by water. In these cases, the water may have a tendency to under run the oil.

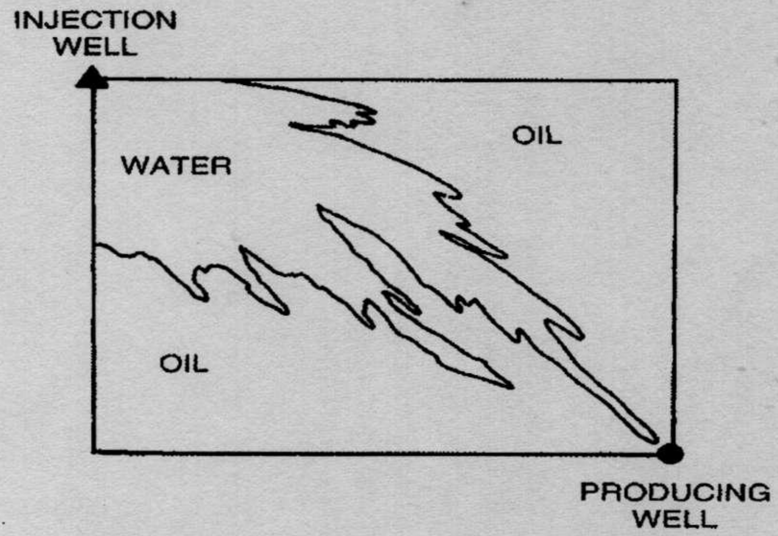
The properties of the reservoir fluid and the injection fluid affect the flood performance. In general, reservoirs containing viscous oil perform relatively poorly in response to a waterflood. When water displaces oil less mobile than itself, the displacement front is unstable, and the water has tendency to "to finger" through the reservoir, causing excessive water production.

Fractures.

If injection and producing wells are located along a line parallel to fracture directions, early breakthroughs occur. If injection wells are located along a line parallel to the direction of the fracture, interference between injectors will cause water to move in a direct line across the fractures towards producing wells. Thus, it is important to know the fracture direction before designing a waterflood pattern. This one factor may dictate success or failure of waterflood.

Viscous fingering.

A problem often encountered in the displacement of oil by water is the viscosity contrast between the two fluids. The adverse mobility ratios that that result promote fingering of water through the more viscous crude oil and can reduce the oil recovery efficiency. An example of viscous fingering shown in figure below.



5.1 ***Performance evaluation.***

Monitoring waterflood performance is critical to the success of the waterflood. From a reservoir engineering stand point, primary concerns are water injectivity and oil productivity. A few important factors related to these concerns will be summarized.

Mobility and Mobility Ratio

Mobility ratio is important in determining the volume of reservoir contacted by the waterflood. Mobility of a fluid is defined as the ratio of the permeability of the formation to a fluid, divided by the fluid viscosity:

$\lambda = k / \mu$

Where μ = mobility, md/cp

k = effective permeability of reservoir rock to

When multiple fluids are flowing through the reservoir, relative permeabilities must be used along with viscosities of the fluids. By convention, the term mobility ratio is defined as the mobility of the displacing fluid divided by the mobility of the displaced fluid. For waterfloods, this is the ratio

of water to oil mobilities. Thus the mobility ratio, M, for a waterflood is:

$M = K_{rw}\,\mu_0 / K_{ro}\,\mu_w$

Where

krw and kro, are relative permeabilities to water andoil, respectively, μ_0 is oil viscosity and μ_w is water viscosity. Prior to 1957, there was no accepted definition, and many workers defined mobility ratio as oil to water mobility; in this case, the reciprocal of mobility ratio (as now accepted)must be used. The oil mobility used in Equation refers to the location in the oil bank ahead of the flood front. For the water mobility, there are several possibilities regarding the location at which the relative permeability should be chosen: at the flood front, at residual oil saturation where only water is flowing (end point), or at some intermediate saturation. It been found a better correlation if the water mobility was determined at the average water saturation behind the flood front at water breakthrough. Thus for the mobility ratio expression, the relative permeability of water is found at the average water saturation at water break-through The mobility ratio of a waterflood will remain constant before breakthrough, but it will increase after water breakthrough corresponding to the increase in water saturation and relative permeability to water in the water-contacted portion of the reservoir. Unless otherwise specified, the term mobility ratio is taken to be the value prior to water breakthrough.

Injectivity and injectivity index.

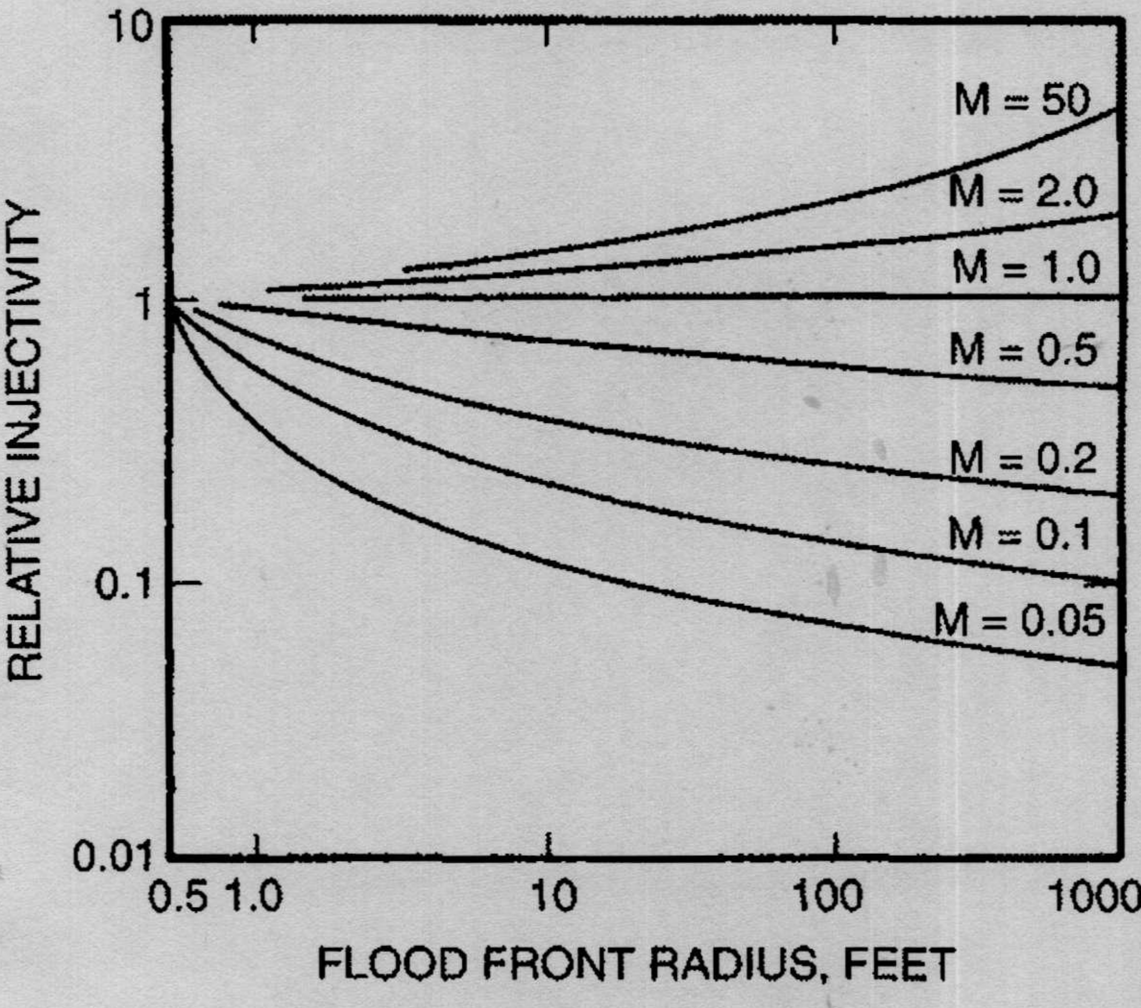
Whereas productivity index was the ability of a well to produce hydrocarbons, injectivity index, I, is a measure of the ability of a well to accept fluids.

$I = q_{sc} / P_{iwf} - P_e$

Where q_{sc} is the flow rate at surface conditions, P_{iwf} is the flowing bottomhole pressure in psi, and P_e is the external pressure in psi. Some engineers express injectivity in terms of q_{sc}/p_{iwf} so that when injectivity given, the reader is cautioned to understand what base pressure was intended. By dividing I by reservoir thickness, a specific injectivity index (specific to one well) can be obtained. Values of injectivity depend on properties of the reservoir rock, well spacing, injection water quality and pressure drop in the reservoir. In waterflooding operations, water injection may begin into reservoir produced by solution-gas- drive in which a mobile gas saturation exists, or injection may begin prior to the development of a mobile gas saturation. In the latter case, the system can be considered filled with liquid.

Injectivities for various Flood Patterns.

Analytical expressions for liquid filled patterns were given by Muskat and Deppe for mobility ratio of one. However, the equations are useful in estimating injectivity in limiting conditions. Fro example, if k and μ are selected for water at residual saturation, an estimate can be made of injectivity at 100% sweep. (These estimates can be useful when equipment is sized for a waterflood. If data on skin factor available, suitable corrections can be inserted in the logarithm term in denominator in these equations. For unit mobility ratio, the injection rate will remain constant during the flood. If the mobility ratio is more than one, the injection rate increases as more water is injected; if the mobility ratio is less than one, the injection rate decreases. Figure below shows, for different mobility ratios, the change in relative injectivity as a 40-acre 5-spot is swept.



For water injection into a depletion drive reservoir, several stages can describe the progress of flood. The first stage is the period of radial flow from start of injection until interference of oil banks from adjacent injectors occurs. The second is the period from interference until fill-up of the pre-existing gas space; after fill-up production response begins. The third stage is the period from fill-up to water breakthrough. The fourth and final stage is the period from water breakthrough until floodout.

Production Curves

Plots of waterflood injection and production performance can be presented in a number of ways. For the history of the project, water injection rate, oil production rate, and water-oil ratio or water cut can be plotted vs. time (usually months). The actual water injection and oil production rates can be compared to the predicted rates on a time basis.

Future oil production and ultimate recovery are often extrapolated from graphical methods. One of the more popular methods is a plot of the WOR on a log scale vs. cumulative oil production on a linear scale or a linear plot of the fractional water cut (or percent water produced) vs. cumulative oil produced. Alternatively, the oil-water ratio can be plotted on a log scale vs. the cumulative production on a linear scale. One of the purposes of these plots is to predict the ultimate oil recovery by extrapolating the curve to some economic limit at which time it becomes no longer profitable to continue the flood. If the operating methods remain relatively unchanged, a method has been proposed for a fully developed waterflood that permits an easy extrapolation of recovery to given water cut. This latter method consists of a linear plot of ER, fractional recovery of oil in place, vs. the term -{[(l/fw) -1] - (l/fw)}. This method also provides an estimate of water-oil relative permeability.

5.2 **Water Injection well behavior**

The initial water-injection rate of a well depends on the (I) effective permeability (2) oil and water viscosity, (3) sand thickness, (4) effective well radius, (5) reservoir pressure, and (6) injection pressure at the sandface. As water begins to fill the reservoir, other factors are introduced to affect the behavior of the injection well. These factors are influenced by the increase in flow resistance as water extends into the reservoir and by the quality of the injection water. The fundamental equation for the rate of water injection into a well is expressed as

$$i_w = \frac{0.00708 k_w h (p_{inj} - p_r)}{\mu_w \ln(r_e / r_w)} \quad .....$$

There are numerous uncertainties that make quantitative applications of the equation difficult. They do not. However impair its usefulness in explaining the relative importance of each of the factors.

<u>Effective Permeability</u>. The symbol *k* ... denotes the effective permeability (millidarcies) of the sand to water. According to laboratory work on clean sands, the relative permeability to water ranges from 30 to 60% of the dry permeability as the water saturation varies from 70 to 85 %. Tests on virgin and artificially oil-saturated cores show that the effective permeability of the sand to water is often less than one-tenth of the dry permeability. Whenever possible, the effective permeability to water should he determined on representative cores from the field.

Sand thickness. The sand thickness, h, is a net effective sand thickness (feet) of the interval that is open for injection.

Pressure. The bottomhole flowing injection pressure p_{iwf} (pounds per square inch) at the sand face can be estimated from the wellhead pressure, the depth of the well, the density of the water, and the flowing pressure gradient, p_e is the effective reservoir pressure.(external boundary pressure)

Well radius. The effective radius of a well, *r*.., (feet) may vary from a few inches to several feet, depending on the type of completion.

Pressure radius. The pressure radius (external boundary radius), *r*, can he estimated, at least roughly, from the amount of water that is injected and from the available pore space, and is the distance from the injection well where the pressure is *Pr'* The available pore space is defined as the total PV less that occupied by interstitial water and oil.

6. **Selection and sizing waterflood plants**

The selection and the sizing of waterflood plant facilities normally are unique to each waterflood because of the natty variable parameters. The primary parameters might be the volume and pressure, while secondary parameters might include the treating requirements and the economic position of the investor. A variation in any single one of these parameters might drastically modify or completely change the selection and sizing of a waterflood plant. The volumes of injection water to be handled will, of course, be the most important basic item of information to learn for determining the size of the plant. Here, too, there are several parameters on which the calculation is based. Essentially, the water volume is a function of the gross size of the reservoir to be flooded, the porosity of the reservoir rock, the anticipated conformity or efficiency of the flood, and the ROS at both the initiation and completion of the flood. These data will be applied to the actual reservoir calculations, and only the final gross volume and the required daily injection rate must he known by the plant designer. As a general rule of thumb 8 to 15 bbl of injected water per barrel of secondary oil, or 1 to 2 PV of injected water, will provide a reasonable estimate of the ultimate water-handling requirements. Daily injection rates may vary from 5 to 25 bbl/ft of pay. The producing-equipment capacity may be a limiting factor in determining the maximum injection rates. A relatively high ratio between the amount of fluid that is injected and the amount of fluid that There are certain other factors that should he considered in designing the proper capacity of the plant facilities. If the available quantity of supply water is relatively small, it is usually necessary to consider produced brine along with other supply waters so that an adequate injection volume is provided. Where the original source water is not compatible with the produced water, or where the produced water is best handled in a closed system and original source water is best handled in an open or semi- open system, flexibility in capacity design will be required. This flexibility is necessary to adjust or to balance capacities between two separate injection systems (one with a constantly increasing load, the other with a constantly diminishingload).

The pressure required to inject water into a formation is a function of formation depth, rock permeability, water quality, and the injection rate that is required. The basic reservoir data and secondary-recovery study will have defined the rock properties so that the anticipated surface pressures can be defined closely, if no adverse effects are anticipated as a result of poor-quality or incompatible water. Poor quality might be because the water contains a large quantity of solids as a result of poor filtration, inadequate settling, precipitation in unstable water, or the growth of bacteria. Incompatibility, might result from mixing injection water with formation water, from the swelling of clay particles, or from chemical reactions between the rock minerals and the injected water. In general it has been found that the pressures than initially are encountered are less than might he anticipated when the only governing factors are depth and permeability: however, increasing pressures should be expected if there is no plan to reduce the injection rate as fill-up is approached. A final factor in predicting Injection rates is the method of production. If the reservoir is to be produced by natural flow, the injection pressure must be sufficient to overcome dynamic hydraulic forces and to support a flowing rate of production. If, on the other hand, production is to be by mechanical means, with producing fluid levels at or near reservoir depth. A considerable reduction in injection-pressure requirements is possible. Consideration should be given to what the maximum allowable pressures should he. As a role of thumb pressure at the surface should not exceed 0.5 psi for every foot of reservoir depth. The maximum wellhead injection pressure will limit the resulting pressure at the perforations, which is less than the parting or fracture pressure. This pressure can he determined by an injectivity test conducted before or during pilot flood operations. Breakdown pressures are often encountered below the 0-5-psi value, and in such circumstances the maximum pressure will be defined by the breakdown pressure. In older fields, or in reservoirs located at considerable depth, the mechanical strength of the injection-well easing may be the deciding factor concerning the pressure limit. This imitation can be. the source and the condition of the supply water will be the most important factors in determining a treating method. It is generally good practice to plan originally on using a closed system that requires little or no treating. Subsequently, the closed system may evolve into one in which the mixing of produced water will require custom—tailoring for conditions that are unique to the particular flood being considered. By starting with a basic treating system, the unit may be expanded into a complete version that may include aeration, chemical treating, flocculation, settling, corrosion inhibition, and bacteria control. In developing the proper treating system for a particular plant, the economic factors that are unique to the situation should be given close attention. If the flood is to be of relatively short duration, it may be profitable to use a system that is less than adequate and to anticipate more than normal maintenance demands. In other circumstances, it might prove most profitable to install corrosion- resistant equipment and to reduce the use of corrosion- inhibiting treatment. Consideration should be given to installing fiberglass tubing or internally plastic-lined tubing in injection wells. Also, if new injection wells are to be drilled, a full or partial string of fiberglass casing should be considered to minimize corrosion and scale buildup, especially in the area across the producing formation. Possibly the last item to be considered by many design engineers, and yet the most important item in many companies, is the financial position of the investor, It is quite possible that a particular operator may have limited investment capital and would find it desirable to keep this sum to a minimum, at the expense of higher future operation costs or additional future investment. The capital investment situation might also affect the choice of injection rate. The operator might be in a financial position in which a low, long-term, constant income would he most advantageous: in other circumstances, a short-term, high-income situation might he most desirable. Under either of these conditions - the normal approach to determining injection rates and plant design would be modified to produce the most desirable income via investment conditions. When the most desirable injection rate as well as the pressure and treating technique have been determined, the plant must be designed to fit the prescribed conditions. For a closed system, the plant design may he extremely simple and yet completely automatic. With in-line, high- pressure filtration equipment and a relatively high- discharge head source well pump, it is possible to use the supply pump as the injection pump and to inject directly from the supply well to the injection well. In this plan, individual cartridge-type well filters may be used if the supply water is relatively free of solids. The next stage in increasing the capacity of the injection plant would be to install a booster pump downstream front the filters, so that the supply pump and filters would not have to operate at injection pressures. The step after that would be to place a gas or oil-blanketed water surge tank between the supply and filter system and the injection pumps. With this arrangement, low-pressure equipment can he used for supply and filtration: if the supply water and produced water are found compatible, produced water can be commingled in the surge tank. Where the systems are separated, it is also possible to use injection pumps with maximum pressure capacities. Further flexibility is also possible in that both source and injection rates can he varied independently, as long as the supply rate is at least as great as the injection rate. Corrosion frequently is minimized in the low-pressure side of this type of system by use of plastics, which also results in cost . If supply water is naturally aerated, the operation of a closed system becomes pointless. Also, because of excessive amounts of dissolved acid gases and/or a high content of dissolved iron, it may be desirable to aerate the water as a treating technique. When an open treating system is being designed, consideration should he given to using natural elevation or substructures to obtain gravity flow through the system. Under these circumstances, open gravity filters good . When a complete chemical-treating program is planned, the most common approach is to have the prefabricated mixing and sludge tank placed immediately ahead of the filters. In certain circumstances, it has been found desirable to deaerate the treated water before using it for injection. Chemical treatments can be used; however, chemicals are too costly except for the removal of very small quantities of oxygen. Counterflow, bubble-tray towers that use natural gas or a vacuum are sometimes used for oxygen removal. However, oxygen is not removed if it can be avoided, because of the relatively high cost of the process; the price must be weighed against the deleterious effects of the entrained oxygen.

Centrifugal pumps have proved most satisfactory for low-pressure supply water and for injection at low pressures. Among the advantages of this type of pump are the small number of its moving parts and its excellent adaptability to volume control: however, in eases in which an appreciable amount of power is to be used, the relatively low efficiencies of centrifugal pumps (particularly when they arc operated at other than design conditions) may preclude their use. In selecting centrifugal pumps, the proper metals should he chosen carefully for both the case and the trim to ensure the best performance. The greatest economy may be achieved with a cheaper pump that is subject to some corrosion rather than with a much more expensive pump, even thought it might not be susceptible to corrosion. The positive-displacement type of injection pump is the most common one n use. Some use has been made of multistage centrifugal pumps; however, they have not yet been widely accepted The most generally accepted type of pump for medium- to high-pressure water injection is of either vertical or horizontal multiclylinder design. These pumps are relatively simple to operate and to maintain, and they can he purchased with a variety of corrosion-resistant parts and accessories. The selection of the proper number of pumps and their capacity is contingent on the present and future requirements for the project. It is, of course, a good practice to provide a standby capacity that is sufficient to maintain continuous injection in ease one pump has a mechanical failure. This can be accomplished by distributing the maximum design load over two or more units so that at least half the injection capacity can be maintained.

A considerable number of filtering techniques are now used in the oil field. These involve ceramic-, metallic-, paper-, and cloth-element pressure filters with sand, gravel, or coal media; and rapid sand pressure filters with sand, coal, or graphite media. The choice of filters is a function of the raw water quality and volume of water required for injection. If solids in the water must be reduced to submicrometer size, one of the element-type or diatomaceous-earth filters, or a combination of the two, is recommended. For less rigorous filtration, the gravity or rapid sand pressure filters arc most widely used. In general, filtration rates are considered normal at about 2 gal/mm-sq ft of filter area; however, this figure will vary considerably depending on the quality of the influent and the desired quality of the effluent. Decreased rates also may be desirable if very frequent backwashing is necessary. The rates and techniques for backwashing are prescribed by the manufacturers of the various types of filters: this function should be considered in plant design to ensure adequate clear-water storage for both back- washing and continuous injection. It may he desirable to install additional filter capacity so that filtration will not stop during backwashing. The addition of standby filtration facilities also offers a guarantee against a total shutdown in which a filter requires a complete change of the filter medium.

7. WATER INJECTION ECONOMICS

Today's economic environment requires oil companies not only to consider water injection as a "cost", but as an operation generating additional value to the asset. Water injection studies should focus at methods to improve the value of the injection water. A successful waterflooding operation may accelerate hydrocarbon production and possibly increase and extend the plateau rate of the production profile. Both the earlier production and improved overall recovery will add to the value of the overall filed development. The difference in the filed value with and without waterflooding represents the value of the injection water.

A degree of down-hole, formation plugging due to contaminants (oil and solid particles) is normally accepted as a practical, economic compromise. Qualification of the degree of damage attributable to a particular type of contaminants in the injection water allows to be set against the potential loss or delay in oil production due to a reduced injection rate. This can then be balanced against savings in water filtration and de-oiling treatment costs. Reliable injectivity prediction methods and an understanding of the uncertainties involved are essential for any water injection planning or operational decisions, e.g.

(1) whether an injectivity decline should be accepted

(2) what type and how frequently a stimulation or other remedial treatment should be used; or

(3) if the injection system should be designed differently from start to reduce the risk of injectivity decline

The underlying message is that careful planning of the water injection scheme during the filed development stage will mist likely be less costly than alterations later in the filed life. The economics of these options should be analyzed and compared fir the particular production circumstances at an early stage in the oriject cycle when they are technically viable. They may need to be reviewed at regular intervals as new information on the injection operation becomes available.

It will have become clear that high and sustained injection well performance is the key to achieving a low cost water injection project. The picture becomes more complex when a choice has to be made between various water sources, each with associated capital (CAPEX) and operating (OPEX) expanses along with various environmental benefits.

An economic cost model was set up which allowed the incremental cost elements associated with either continuing with an improved SWI operation (monitoring, water treatment and regular workovers) or implementing AWI or AW/PWI process. Table below summarizes the input data and the model results. Note, it has been assumed that PWI requires little additional expenditure as treatment facilities for offshore disposal are already in place. However, significant additional cost for AW supply will be incurred. The potential of a lower operation cost and a reduced Environmental Impact associated with mixed AW/PWI, based on the created scenario, can be seen from Table.

_ Cost elements involved when changing water injection scheme, presented in terms of cost in US$ per bbl of total daily injection rate (20,000 m^3 day^{-1})

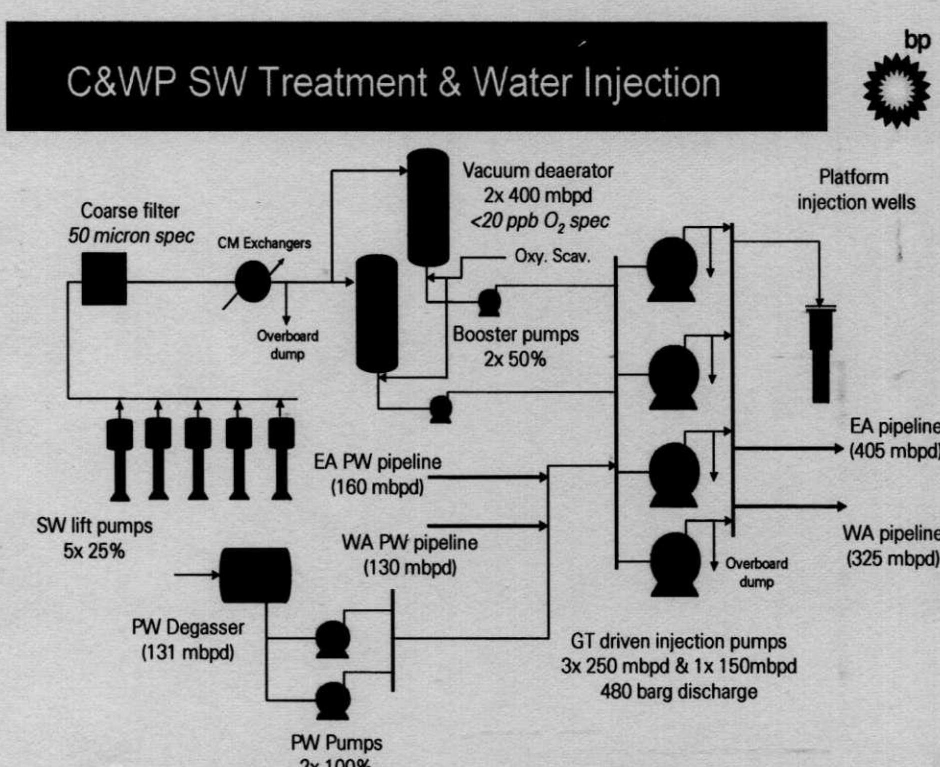
Cost elements	SWI	AWI	AWI + PWI
Incremental CAPEX;	$0	$2,500.000	$1,750.000
Increased well cost(AW producer required)	$0	$6,000.000	$3,000.000
Increased treatment equipment cost (AW treatment equipment is required)	$0	$500,000	$250,000
Increased injection pump cost(need increased pumping power for PW)	$0	$0	$500,000
Incremental OPEX/bbl over base case (scaling SWI)	$0,245	$0,172	$0,125
Incremental `average `pump cost/bbl	$0.004	$0.004	$0.011
Incremental chemical injection(SW,scale and corrosion inhibitors,)	$0.200	$0.100	$0.075
Plant maintenance(SW, scale removal; AW, corrosion; PW, erosion)/bbl	$0.040	$0.020	$0.015
AW lifting ($0.06/bbl AW)	$0.000	$0.047	$0.024
Increased monitoring effort(water quality, injection profile and performance	$0.001	$0.001	$0.001
Tubing replacement(SW, 4 years; AW, 5 years; PW, 3 years) $200,000 each			

Acid stimulation per well(SW,2/year; AW, 1/year; AW+PW, 4/year) \$50,000 each			
SWI, 2 injectors and 2 AW producers;			
AW/PWRI, 2 injectors and 1 AW producer			
Total volume of produced water processed ;	$10,000m^3day^{-1}$	$10,000m^3day^{-1}$	$10,000m^3day^{-1}$
Total volume of water disposed overboard;	$10,000m^3day^{-1}$	$10,000m^3day^{-1}$	$0m^3day^{-1}$
Total volume of injection water prepared;	$20,000m^3day^{-1}$	$20,000m^3day^{-1}$	$10,000m^3day^{-1}$

8. Topsides overview of particular project.

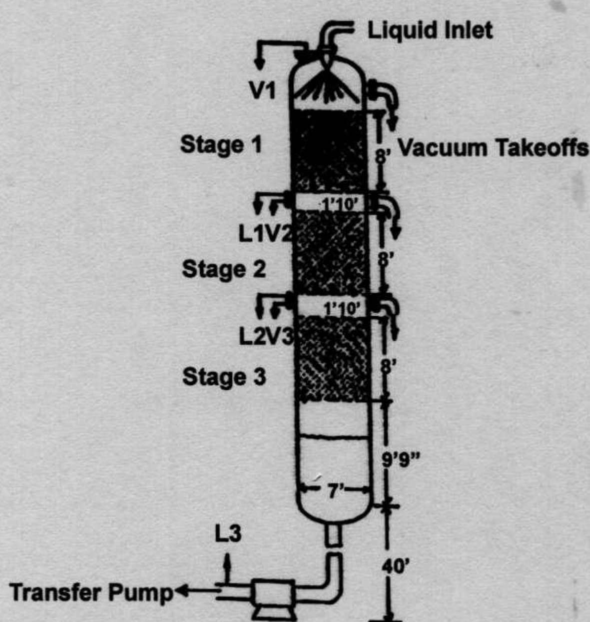
Description

The Azeri water injection system is designed to deaerate seawater and inject commingled produced water and seawater. The system is designed for deaerating up to 5290 m3/h (800,000 bwpd) of seawater and injecting up to 6600 m3/h (1,000,000 bwpd) of commingled produced water and seawater to the reservoir at a wellhead pressure of 440-450 barg (6400-6500 psig). The combination of high flow and high injection pressure makes this water injection system the largest ever built with a total power input in excess of 100 MW The seawater is deaerated to a specification of 0.005 mg of oxygen/litre of treated seawater (5 parts per billion). This is achieved by a combination of mechanical deaeration in a vacuum tower and chemical scavenging of residual oxygen. The injection system receives water from the Seawater system, prepares the water for injection by removal of oxygen under vacuum conditions, and raises it to injection pressure through two pumping stages. The first stage (booster stage) raises the pressure from the vacuum conditions in the deaerator to a pressure suitable to meet NPSH requirements for the main Water Injection Pumps. The second stage (Water Injection Pump) raises the water to the pressure required for injection into the wells.



Picture shows CA – CWP platform Seawater treatment and Water injection facilities. 4 of high pressure Water Injection pumps was specially ordered by BP to Sulzer Pump manufacture as worlds the biggest and highest capacity pumps at that time (2005) 6600 m3/h (1,000,000 bwpd) at pressure 480 Barg

Three Stage Vacuum Tower



8.1 <u>Seawater treatment.</u>

Purpose of seawater treatment can be divided into 3 stages

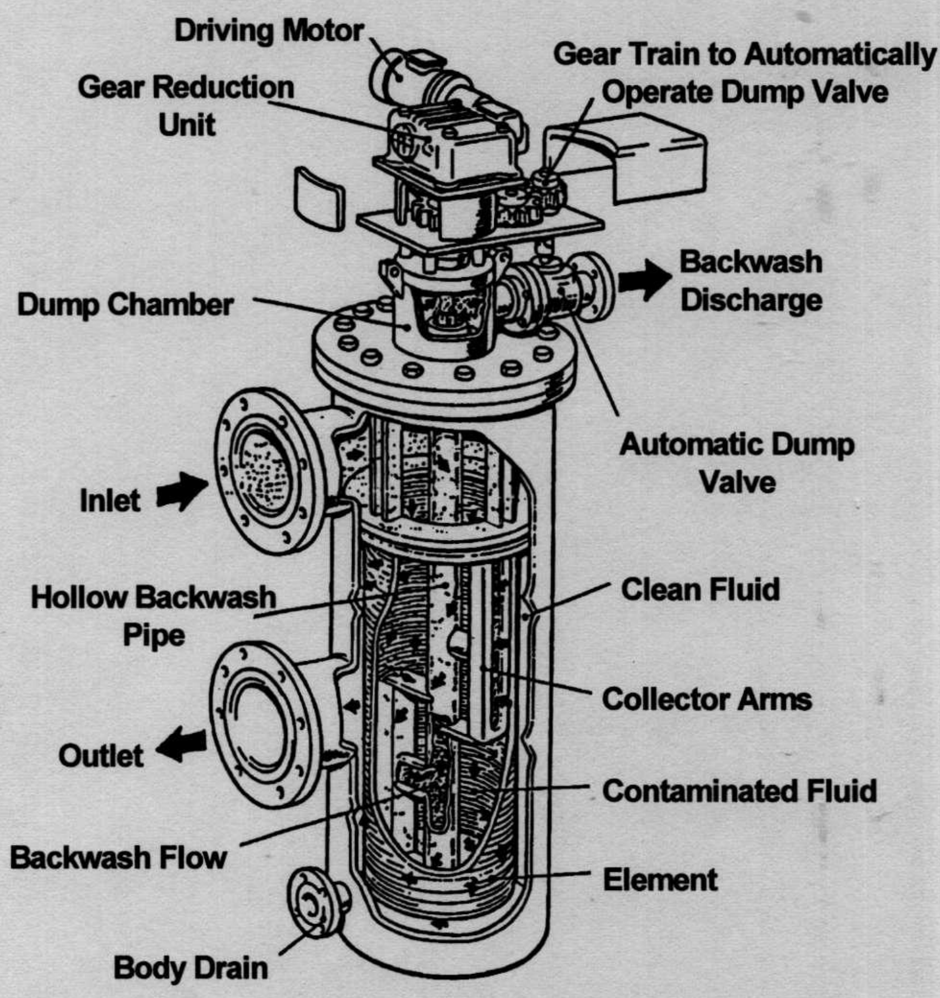
To remove solids from seawater in order to reduce erosional corrosion and to minimize injectivity declines

Oxygen removal from seawater to reduce(oxygen) corrosion and bacterial activity.

Bacterial control of seawater to reduce corrosion and to reduce possible reservoir souring

On ACG fields Seawater is filtered to 150 microns in the Seawater Coarse Filter Package which incorporates two 100% filters with automatic back flushing facilities. The filtered seawater is continuously distributed to the Water Injection Vacuum Package. Warm seawater from the Cooling Medium Coolers is then deaerated and injected into the reservoir. Any excess seawater from the coolers that is not used for water injection is dumped overboard via pressure control valve.

Typical Seawater Coarse filter.



CHEMICALS

A variety of trials have indicated that only minimal chemical treatment of the injection system is necessary – the major requirement being chlorine, with an occasional use of oxygen scavenger and biocide. Some of the more interesting observations are discussed below.

Oxygen Scavengers

Chemical trials have indicated that sodium sulphite, even with a cobalt catalyst present, would not scavenge residual oxygen unless the pH was >7.8 and solutions of the catalyzed scavenger were sensitive to atmospheric oxygen. Ammonium bisulphate was relatively insensitive to atmospheric oxygen and less sensitive to pH. However, at the system pH of 6.5 the ammonium bisulphate would not scavenge 30ppb of residual oxygen unless chlorine was present in the system.

Detailed studies by BP Research Centre corrosion engineers showed that excessive oxygen scavenger must not be added to the system, otherwise there is a significant increase in corrosion rate. Under normal deoxygenation tower operations while trying to scavenge the last 30 ppb of oxygen it was shown that only 1-2 ppm of scavenger was needed to reduce the residual oxygen to 2ppb (instrument zero) and scavenger doses of 15 ppm and 50 ppm gave corrosion rates of 31 and 56 mpy, respectively. When the stripping gas to the deoxygenation tower was reduced to about one-fifth of its normal rate, to leave excessive in the water, then scavenger doses of 18ppm and 43 ppm had no significant effect on the corrosion rate.

It was noted above that the presence of ch had an advantageous effect on filtration performance and so care has to be exercise, if oxygen scavenger is used, to retain reschlorine at the fine filters. This was not allowed for in the original design.

Oxygen scavenger used on CA-CWP compression and water injection platform rated as below;

Chemical name; Oxygen scavenger

Function; Corrosion control

Dosage; 2-10 ppm or sufficient for 0.64 mg/l sulphite residual at Inj. pump inlet

Chemical: OS2

Performance target: O2 < 10 ppb & bisulphite < 1 ppm

Performance monitoring method: Online O2 meter, Chemet detection tubes, residual bisulphite test kit, corrosion monitoring.

Performance monitoring frequency: Continuous w/ online meter

Scale inhibitors.

Scale formation in the water injection plant is not a problem, although stability index calculations (2) predict that North Sea water could be carbonate scaling above about 50°C. This cause no problem as the injection water is at 8-12°C. The potential problem is further alleviated as the pH is kept on the acid side by the presence of carbon dioxide in the stripping gas used for deoxygenation. Some of the seawater is however used in heat exchangers to cool the product gas and here the skin temperature is around 80°C. However, inspection has shown no signs of carbonate scale.

The only serious scale problem occurs on mixing the seawater, which contains sulphations, with the formation water, which contains barium and strontium, thus precipitating probably the worst oilfield scales, barium and strontium sulphate.

The solubility of barium sulphate is generally calculated as a function of temperature a mixing (formation/injection water) composition. The result can then be presented as stability index, which is the logarithm of the ratio of actual barium sulphate present to the barium solubility under the specified conditions. It can be seen that the worse conditions exists for relatively large amounts of injection water. Such a situation could exist during the initial period of injection into the well or in the early stages of injection – water breakthrough around a producing well.

The first physical evidence of the barium sulphate problem came when a jet pump, driven by sea water, was used to backflow the water injection wells prior to their completion.

A barium sulphate scale inhibitor is, therefore added to the injection water for the first 3-4 weeks of injection into a new well, to prevent scale precipitation in the immediate vicinity of the wellbore, and thus impede… injection. Also, the BP Research Centre embarked on an evaluation of proprietary scale inhibitors to find the most suitable materials and started to investigate inhibitor for squeeze treatments and possible solubiliser for the barium and strontium sulphate scale in anticipation of the production well problems later in life of Forties.

Recommendations were made to the operation area of the most suitable inhibitors for the injection system, but their need is limited to initial injection into a new well, addition to work over fluids and addition to seawater used to wash the production separators free of sand. Evaluation of inhibitors for production well squeeze treatments is ongoing, but a solubiliser for barium and strontium sulphates has been found. The solubiliser has so far only been laboratory tested on samples of filed scales, but it is hoped to try a filed test in the near future.

Scale Inhibitor

Function: $BaSO_4$ and $CaCO_3$ scale control

Chemical: Gyptron SA960

Dosage: ~20 ppm, treat 1st 400,000 bbls of water per well. Champion recommended application is to maintain 10ppm during injection of the first 100,000 bbls of seawater

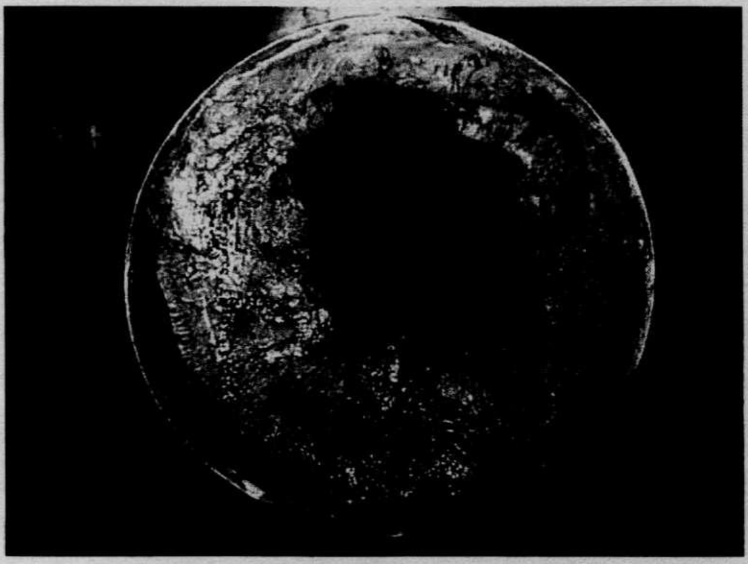
Injection point: Downhole, U/S of water injection booster pumps

Performance target: No scaling

Performance monitoring method: No indication of scale

Performance monitoring frequency: Continuous

Scaled well casing.



Biocide

Micro-organisms present in Caspian Sea Water are not a problem on entering the system, but if they are allowed to settle and grow then considerable problems can arise. The two main areas of concern are:

General aerobic and anaerobic growth

Growth of sulphate reducing bacteria

Control of bacteria by organic biocides presents a problem because of the development of mutations than can tolerate the biocide and hence the biocide has to be constantly changed to achieve adequate protection. Many organic biocides have been screened, by the BP Research Centre microbiologists, to determine their effectiveness, but they are only applied as a secondary measure.

Chlorination is utilized as the general control chemical because of its indiscriminate actions, thereby preventing resistant strains developing, its low dosage rate required, which is particularly important in reducing the logistical problems of supplying offshore locations, and its non-toxicity to man at the dosage level as important requirement when potable water is supplied from the distillation of seawater originating in the injection system.

Chlorination is achieved by the addition of concentrated (14 per cent) solution of sodium hypochlorite immediately downstream of the seawater winning pumps. It was originally intended to install electrochlorinators to generate chlorine by electrolysis. A subsequent accident on a North Sea platform with an electrochlorinator eventually tipped the balance in favour of continuing to inject sodium hypochlorite solution. Handling bulk quantities of this solution can be a hazardous operation and it has meant that modifications have had to be made to provide a permanent system to handle the transfer of the hypochlorite from the transport containers on the top deck of the platform through titanium pipework to a storage vessel at the required location on the bottom deck.

Injection of 1-1.5 ppm of sodium hypochlorite gives a residual chlorine level of 0.3-0.4 ppm upstream of the fine filters. At least 0.4 ppm of the loss occurs across the deoxygenation towers. The chlorination seems to prevent the proliferation of bacteria and sometimes reduces their numbers. It would be tempting to increase the hypochlorite dosage to provide more killing powder, but the corrosion engineers have demonstrated that increasing the chlorine residual in the system increases corrosion, so once again the system has to be balanced for the two opposing effects. If the sulphate reducing bacteria become a serious problem, then either the level of residual chlorine will have to be increase for a sufficient period to control their growth, at the expense of some corrosion, or the system will have to be batch treated with an organic biocide.

Primary Biocide (Generated Sodium Hypochlorite)

Function: Biomass control

Dosage: In-situ generation or 10 ppm during generator outage

Sufficient for 0.3 mg/l free Chlorine residual at D/A inlet

Injection point: U/S of SW lift pumps

Performance target: 0.3 – 0.6 ppm residual chlorine at the DA outlet

Performance monitoring method: DPD tablets (calorimetric test) to measure free chlorine content

Performance monitoring frequency: Daily

9. **Case studies.**

It is generally acknowledged that the first water injection occurred as a result of accidental waterflood in the Pithole City area of Pennsylvania in 1865. As long ago as 1880 it was concluded that water, finding its way into wellbore from shallow sands, would move through oil sands and be beneficial in increasing oil recovery: Since that time waterflooding has become dominant technique employed in worldwide oil recovery operations.

Value of water to ACG field.

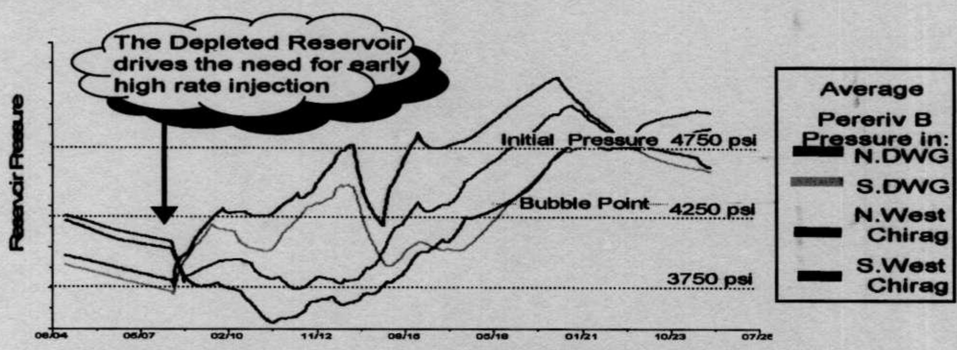
Waterflooding is dominated technique for BP and all other giant oil companies. Brief info about waterflood track on BP worldwide can show us importance of water injection for oil companies.

BP-TNK produce 4.5-4.9 mmbwpd and injects 6mmbwpd. Ssame BP-TNK reinject 80% of Produced water.

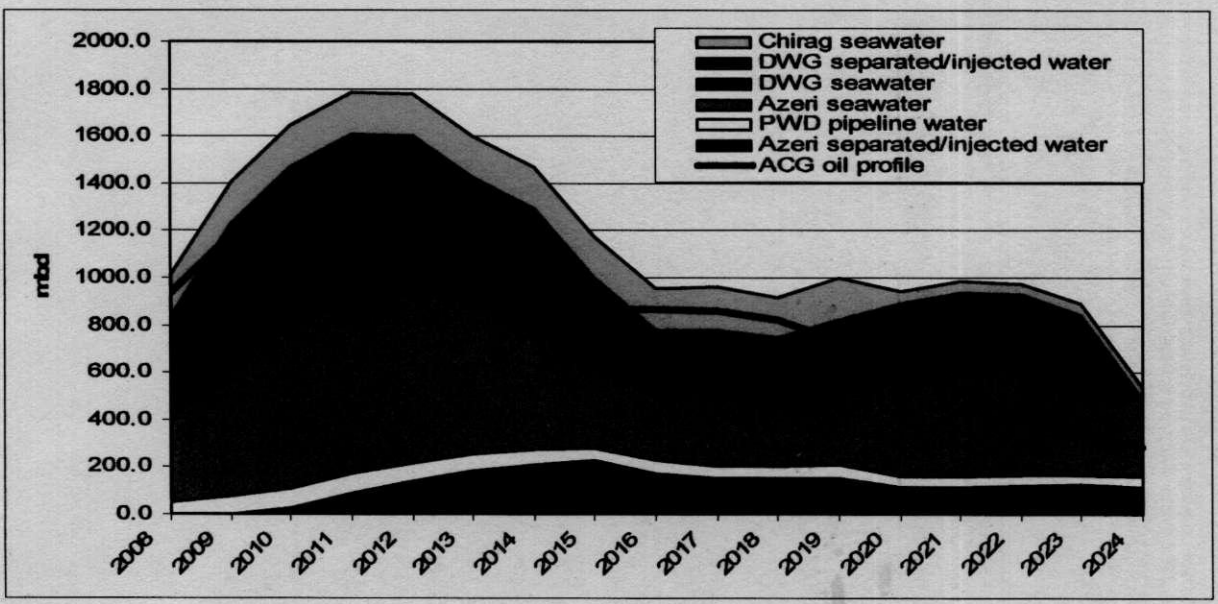
Azeri Chirag Gunashli will inject 750/2000 mbwpd. Waterflood will underpin 80% of our oil production in 2010. We are building equivalent Water Injection capacity of 4 North sea SPU`s in this time frame. Soon Azerbaijan (2mmbwipd) will account 20% of BP water injection capacity.

Reservior pressure directly impacts production capability of all producers.

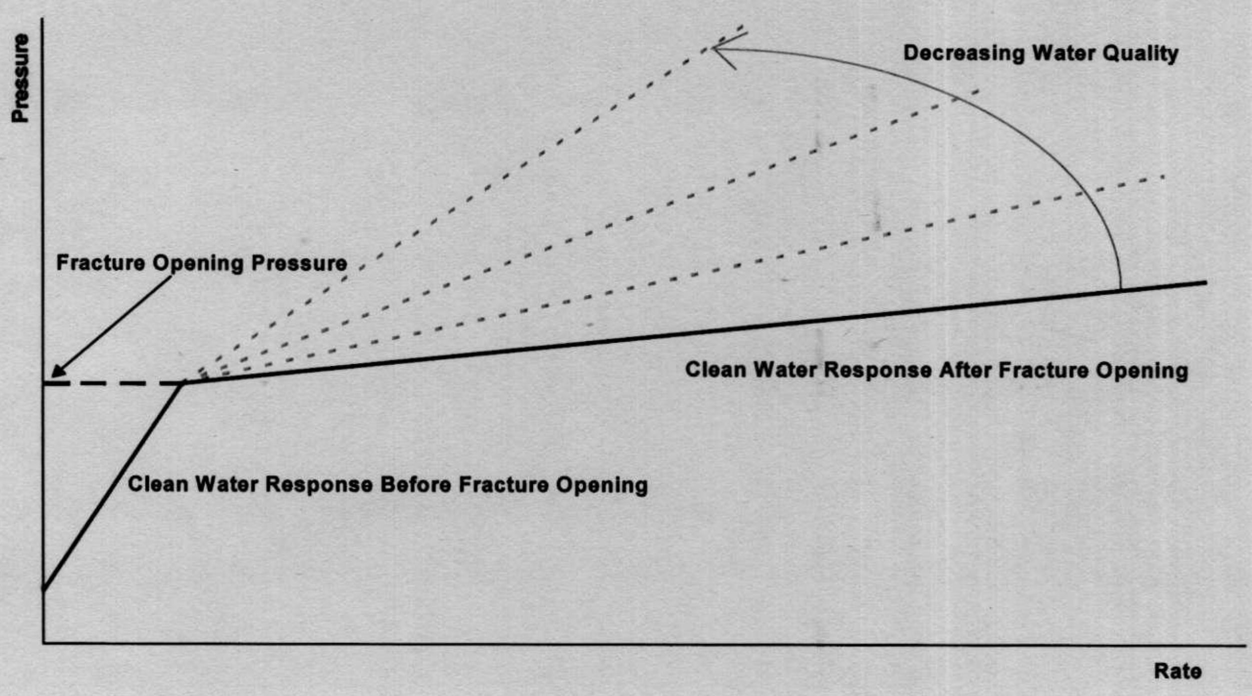
6-9 bbls water = 1 bbl of oil



Criticality of High Rate Water Injection
- reservoir depletion of 1000psi on start up



Injection above fracture pressure is fundamental for sustained water injection rates in most areas. It applies to sea water and in particular Produced water. By increasing injectivity we can reduce number of wells.



9.1 *Key messages of injection Management*

Sustainable injection usually requires pressures > fracture pressure.

Matrix injection is rarely sustainable without frequent stimulation(expect in fractured reservoir, or with low pH injection water)

Topside and subsea design must allow for injection above fracture pressure(minimum standard)

Well trajectory (azimuth and deviation) vs fracture direction is important

Fractures tend to cause poor conformance if left to develop unchecked

Water injector initial clean up procedure must be in place and implemented

First 24 operation can materially impact long term performance

Use reservoir description/geomechanics/structure for best advantage

Injection well measurement and control must be improved.

Remotely operated chokes should be installed for injectors in subsea devolopment

Installation of DHPG strongly recommended for all injectors

<u>Injection water quality impact on screens/gravel packs</u>

Plugging of screens:

Bridging theory indicates injected solids need to < 1/3 openings in screen. For example:

8 gauge (200 μm) will plug with particles > 66μm

9gauge (225μm) will plug with particles > 75μm

Plugging of gravel:

To prevent deep plugging of the gravel pack, the injected solids need to be < 1/7 of the gravel mean pore throat diameter. For example:

20/40 Carbolite (mean pore throat dia. 170μm) will plug with particles > 24μm

<u>Water treatment requirements.</u>

Oxygen removal governed by;

Dalton`s law

$P_T = P_1 + P_2 + P_3$

(total pressure exerted by a gas mixture = the sum of the partial pressures of the individual components)

Henry Law

$C = kP$

(amount of gas dissolved in a liquid is proportional to the partial pressure of the gas above the liquid)

Temperature;

The solubility of a gas decreases with increasing temperature.

9.2 *Design issues on deaerator tower CA-CWP platform.*

Principles of work of Deaerator tower

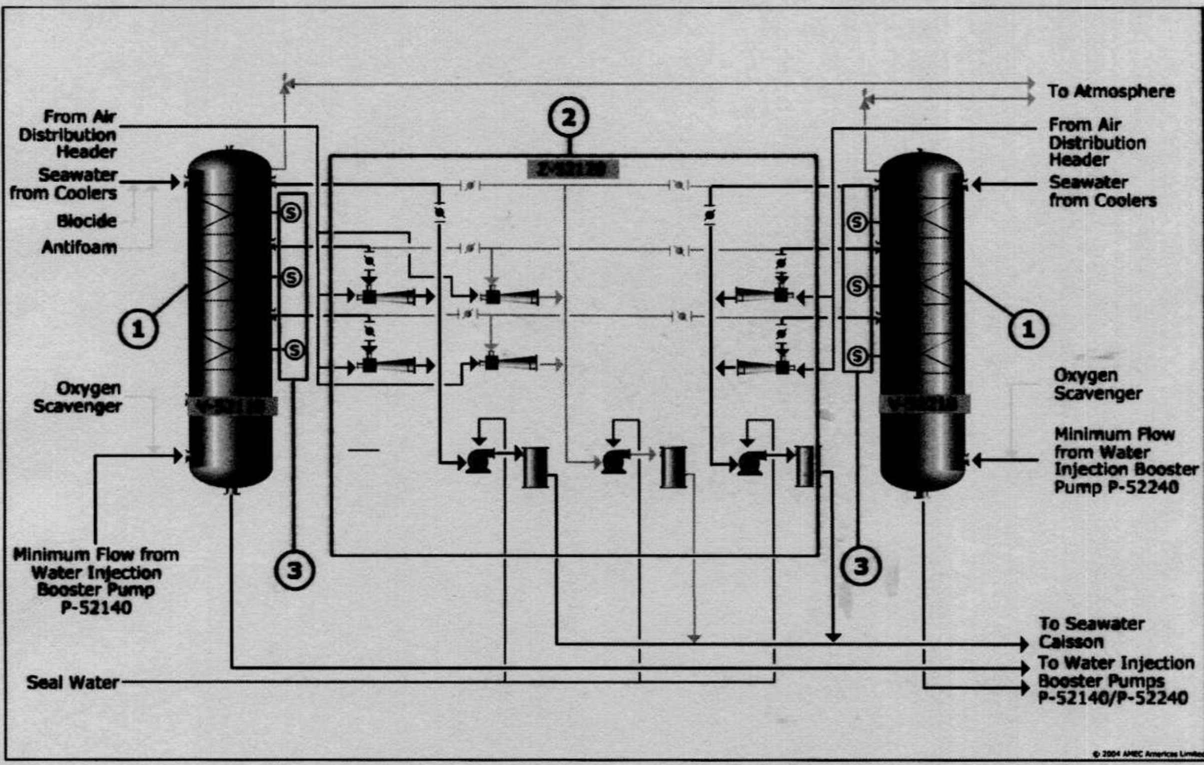
One of design issues was spotted on CA-CWP platform Deaerator tower Oxygen Scavenger injection point by me on January 2008.

The injection water deaeration system removes dissolved oxygen from the seawater prior to injection into the injection wells. Removal of oxygen is necessary because oxygen accelerates pipeline corrosion. Seawater must be deaerated to 5 ppb prior to injection. This is accomplished using a combination of mechanical deaeration and chemical scavenging of residual oxygen. Each tower is fitted with three packed beds of No. 2 Beta Ring polypropylene packing and associated water distributors and seal pans, and operate under vacuum. As well, each of the packed beds has a sample point, equipped with a sampling cup and dip pipe, to obtain seawater samples for analysis. Deaeration is necessary prior to water injection, as the oxygen in seawater makes it highly corrosive. The prolonged use of seawater with a dissolved oxygen concentration above 10 ppb is not acceptable. Even short fluctuations in the dissolved oxygen content are very damaging to the pipelines.

Oxygen from the vapour in the deaerator towers is continuously evacuated by vacuum pumps to reduce the oxygen partial pressure in the towers to near zero. This creates a driving force for oxygen molecules dissolved in the water to diffuse to the liquid surface and into the vapour phase, thereby reducing the concentration of oxygen in the water. The deaerator towers are three stage deaerator towers, with a pressure drop at each stage. The first stage performs removal of oxygen at a relatively high pressure. In the second and third stages, additional removal is achieved at lower absolute pressures. Final removal of oxygen is achieved by the injection of oxygen scavenger at the tower outlet.

Issues observed

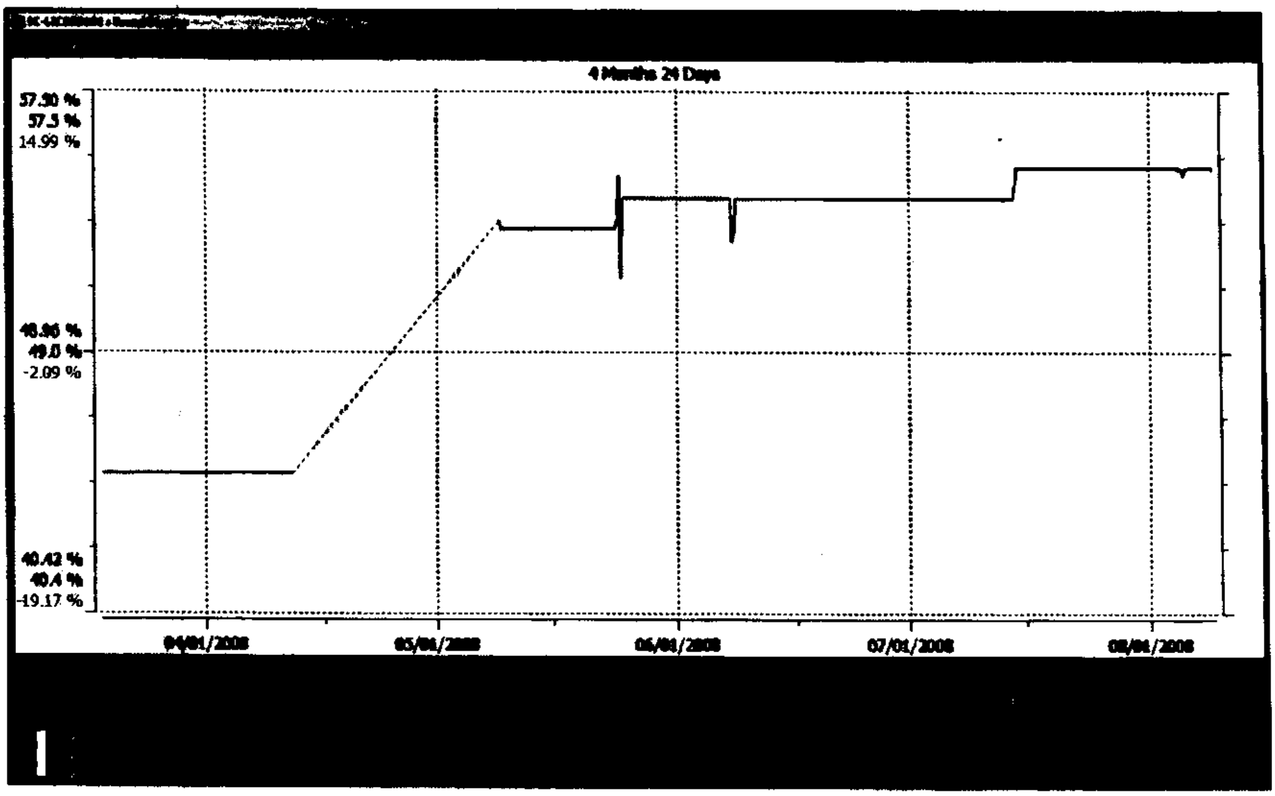
Issue was raised about deaeration tower Oxygen Scavenger injection point on January 2008. Oxygen scavenger has been injected to deaerator tower 11 litres per, hour as per recommendations from Champion chemical supply company.



But sample result of injected sea water which was taken from outlet of deaerator tower was showing dissolved oxygen level too high which could cause pipeline corrosion by oxygen in the injected water. After discussion with Operations team and after review of tower design and injection point location, it was suspected that Oxygen Scavenger injection point designed and implemented in wrong manner, so that injected chemical didn`t have enough time and space to mix with water and remove residual oxygen. Offer was given to increase treated water level in tower, so Oxy Scav. can mix with water and perform it`s task.

From graph below you can see trend display of level indicator for 4 days.

Continuous samples were taken during these days.



Sample results showed residual oxygen concentration decreased and become less than 10 ppb, which was on acceptable levels.. This helped us to continue injection of water to West Azeri platform with correct concentration of oxygen in the injected seawater. Engineering Query was raised at the same time to change location of injection point on tower, so chemical can mix with water for oxygen removal and injected water do not do any damage to pipeline.

10. CONCLUSIONS

The thesis includes introduction, four sections, conclusion and references.

In the Introduction urgency of a theme, the object of the thesis, ways of solving problems were considered.

Water injection is an essential part of many modern oilfield devolepement plans. The choosen design must not only maximize the oil production revenue, but also carry a acceptable level of risk in terms of the project costs and technical uncertainties.

Well injectivity, which describes the well to reservoir connection , is a central factor in any water injection operation. The formation characteristics, water properties, well configurations and injection water pressure determine this.

Water injection rate calculation is a critical parameter in a waterflood design. Several methods can be used to estimate water injection rate. Darcy radial flow equation is the simplest of them. Muskat equation is used for single well calculation. Craig proposed a method to estimate the multi-well injection rate. The water injection rate estimated from the equations needs confirmation from a field injection test.

When Injection rate is plotted against the bottom hole pressure, a break in the curve results at the parting of formation fracture pressure. The parting pressure gradient, normally 1psi/ft of the well depth, may vary from 0.75 to 1,2 psi/ft. Above the parting pressure water can be injected at higher rates per increment of pressure

Properties of injection water one of the most important factors defining the injectivity. "Water Quality" is determined by source of the water injection and its treatment prior to injection. Only minimal chemical treatment of the injection system is necessary – the major requirement being chlorine, with an occasional use of oxygen scavenger and biocide

Many parameters impact the performance of a water injection project. Integration of the key technical and economical elements allows the development of a holistic approach to the water injection process.

Waterflooding currently accepted worldwide as a reliable and economic recovery technique; almost every significant oil field that doesn`t have a natural water drive has been , is being, or will be considered for waterflooding.

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