Waterflooding Heterogeneous Reservoirs: An Overview of Industry Experiences and Practices


Abstract

This paper reviews waterflood management practices, highlighting key industry papers. It is intended to move readers up the “learning curve” and provide a road map for implementing and operating a successful waterflood project. It will assist reservoir engineers, production-operations engineers, and development geologists who are involved in or are contemplating waterflood operations.

The paper addresses operating philosophy, well spacing (density), pattern development (selection), completions, injection water, and surveillance. Although these factors are presented from a west Texas perspective, they are applicable to reservoirs having high degree of vertical and areal heterogeneity.

In addition to a brief history of waterflooding, the paper reflects “lessons learned” through years of experience in waterflooding and CO₂ flooding carbonate reservoirs, principally in west Texas. This experience has been gained through work in both a major and a large independent oil company, through interfacing with outside operators of all sizes, and through consulting for small, independent oil companies.

Introduction

Many of the world’s oil reservoirs produce by a solution gas drive mechanism. This drive mechanism has inherently low reservoir energy, which usually leaves a large portion of the original oil in place in the reservoir when the wells reach their economic limit. In addition, many of these oil reservoirs are heterogeneous. That is, these fields are not thick, clean, sand sections with strong water drives.

One of the cheapest and most popular methods of restoring and maintaining reservoir energy is to inject water into the reservoir; i.e., waterflooding. Although this process has been around for over 50 years, the fundamentals are buried in numerous papers and books. This paper presents the essentials of waterflooding that the authors have discovered throughout their careers, supported by excerpts from the literature.

A Brief History of Waterflooding

Although the history of waterflooding dates back as early as 1865, the use of waterflooding as a recovery method did not come into widespread acceptance and use until the early 1950’s.1 In west Texas, there was a significant expansion of the oil industry in the 1950’s with the discovery of a number of very large fields such as Wasson, Slaughter, Levelland, North and South Cowden, Means, and Seminole. Statewide rules forced most fields to be developed on a density of 40 acres per producing well. These solution gas drive reservoirs were found in highly heterogeneous shallow shelf carbonates.2-5 Consequently, reservoir energy depleted within a few short years and producing rates dropped rapidly. To compound matters, many of the wells were completed in only the high permeability streaks and well above any possible water production.

Water injection was implemented to restore oil production rates. The typical waterflood development scenario went something like this: First, some wells around the perimeter of the property were converted to water injection, thus creating a “peripheral waterflood.” An alternative scheme was a single line of injectors through the center of the field.6,7 When this had only minimal effect, largely due to low injectivity in the relatively low permeability reservoirs (0.1 to 20 md.), some interior wells were converted to water injection. Often the wells converted were the poorer producing wells or were selected so as to set up an inverted 9-spot pattern (3 producing wells for every injection well). In the 1970’s, it was realized that the conversion of wells to water injection effectively raised the density of producing wells to a value greater than 40 acres per producing well. Drilling additional producing wells...
and converting more wells to injection, so as to return to a well density of 40 acres per producing well, usually created an infill drilled pattern waterflood with one producing well for every injection well. This yielded a total well density of 20 acres per well. In addition to accelerating production, the higher well density increased ultimate recovery. As time progressed, watercuts increased and wells were worked over. Lower permeability pay could be opened and completion intervals extended closer to the oil-water contact, thus improving production but not increasing the watercut.5

Basic Waterflooding Philosophy
Waterflooding is largely common sense. If one sets out a plan and executes it, the project’s success is significantly improved. The key tenets of a successful waterflooding plan are:

- Start the waterflood early in the field’s life.
- Understand the reservoir’s geology.
- Infill drill to reduce lateral pay discontinuities.
- Develop the field with a pattern waterflood that has one injection well per producing well (i.e., 5-spot or line drive).
- Have all of the pay open in both injection wells and producing wells.
- Keep all producing wells pumped off.
- Inject below formation parting pressure.
- Inject clean water.
- Operate the waterflood based on injection well tests.
- Conduct a surveillance program.

The remainder of this paper examines each of these tenets and integrates them into a unified philosophy.

Early Waterflood Start-up
When primary depletion occurs, the reservoir pressure drops to the oil’s saturation pressure (bubble point), and then gas starts coming out of solution in the reservoir. With additional depletion, gas saturation is created in the reservoir. When waterflooding is started, this gas saturation must be collapsed before waterflood response can occur. The delay in waterflood response hurts the economics of the project. In addition, the loss of solution gas from the crude oil increases the viscosity of the oil, thereby lowering the flow rate of oil. The increase in viscosity also adversely affects the mobility ratio, which in turn decreases the areal sweep efficiency.

If the reservoir reaches an advanced state of depletion prior to the start of water injection, the project may be doomed to failure. A plot of producing gas-oil ratio (GOR) versus cumulative oil production for a solution gas drive reservoir will start out at a constant value until the bubble point is reached, will increase to a maximum value, and then will rapidly decrease.6 If a field’s GOR is in this last stage, the reservoir may be too depleted to be successfully waterflooded.

These two points suggest that an early start to waterflooding will speed up the recovery process and thereby improve the economic performance of the field. Start-up of waterflood operations early in a field’s life, even in very large offshore fields, has been successful in the past.9

Understanding the Field’s Geology
It is hard to develop or redevelop a field in the optimum manner if the field’s geology is not well understood. It is critical for reservoir studies that as much data as possible be collected for each well. For starters, a good suite of openhole logs, including gamma ray, neutron porosity, density porosity, acoustic porosity (for synthetic seismic to tie back to 2-D and 3-D seismic data and for stress profiles to design stimulations), deep resistivity, and Rxo logs are a must. It has also been proven that a 200 MHz di-electric log can be very beneficial in determining the oil-water contact. Some people are tempted to forego openhole logging of infill wells. This is a big mistake! Reservoirs can change dramatically between wells, especially in shallow shelf carbonates. Every round of drilling has brought changes in the geological description of a reservoir.

Besides logs, a good areal distribution of whole cores that cut the entire section are necessary to define the permeability distributions throughout the field. Observation of a core that is fresh out of the core barrel, especially in a 30-year-old waterflood, can give the engineer (and even the geologist) great insights into what makes that field tick. If the reservoir is believed to be fractured, an oriented core can reveal the orientation of those fractures. This knowledge will greatly help in orientation of the waterflood patterns.

Almost as important to a newly discovered field as openhole logs, are a bottomhole sample of the produced fluids and a bottomhole pressure measurement. These are often overlooked in the excitement of a new discovery, but almost every reservoir engineer has lamented not having (and probably cursed his/her predecessor for not obtaining) these data. The costs of obtaining and analyzing a fluid sample and getting a pressure measurement are insignificant with respect to the cost of field development.

If a carefully controlled pressure drawdown test, immediately followed by a pressure buildup test, is conducted early in the producing life of the field, such reservoir characteristics as permeability-thickness, drainage radius, distance to reservoir boundaries, and determination of whether the reservoir is a dual porosity system can be ascertained. Factors critical to such testing are 1) proper design of the test, especially if it is a layered reservoir, 2) conduct the test before a free gas saturation is established, and 3) test as many wells as possible.10

Many companies have created multi-disciplinary teams, including geologists, geophysicists, petrophysicists, reservoir engineers, production engineers, and facilities engineers, whose job is to study older waterflood projects in an attempt to improve recovery. Such teams have generally worked well.5,6,11,12 This appears to be due to increased communications and awareness of the level of detail required for building reservoir descriptions to be used in full field reservoir simulations. In general, stratified reservoirs must be
mapped on a much finer vertical resolution than customary for most geologists. For example, a reservoir that would normally be mapped as two or three zones may require subdivision into eight or ten zones and the aquifer layers may have to be quantified. Typically this is done by correlating and mapping the major vertical barriers to flow, then mapping the pay in between. In addition, research shows that capillary pressure forces in oil-wet carbonates can create barriers to the vertical flow of water.\textsuperscript{13}

**Well Density**

In heterogeneous reservoirs, changes in facies trap oil or shield the oil from the sweeping action of injection water. Driscoll\textsuperscript{14} discussed the concept of lateral pay discontinuities. Reducing the inter-well distance through infill drilling reduces these lateral pay discontinuities, thus improving areal and vertical sweep efficiencies and increasing recovery. Time and again this concept has proven true.\textsuperscript{14-18} In west Texas, almost every San Andres and Clearfork field has been infill drilled to at least 20 acres per well and some have been reduced to 10 and even 5 acres per well, always with an increase in ultimate recovery. (If there were no increase in reservoir continuity, the producing rate would increase but the ultimate recovery would remain the same.)

After an extensive study of a number of closely spaced 4-inch diameter whole cores from the Reeves (San Andres) field in Yoakum County, TX, Danielli\textsuperscript{7} concluded that the flow units in this shallow shelf dolomite could not be tracked from one well to the next if the well density was more than about 10 acres per well (660 ft between wells). Her conclusions about the areal and vertical heterogeneity of these type reservoirs lend strong geological support as to why infill drilling increases recovery.

Prudhoe Bay benefited from infill drilling and waterflood pattern size reduction.\textsuperscript{18} It has even been reported that a thick (950 ft of oil column) relatively clean sandstone of high porosity (22\%) and relatively high permeability (640 md) had an increase in ultimate recovery from infill drilling.\textsuperscript{19}

Besides the issue of lateral pay discontinuities is the issue of the time it will take to sweep the reservoir volume. Obviously, higher well density means more oil recovered in a shorter time.

Starting a waterflood at one well density and then downsSpacing to a higher well density can have adverse consequences. The relative permeability effects of water from the original injection patterns may lead to water cycling on one side of a pattern while the other side is in the prime of its waterflood response. Therefore, infill drilling prior to starting a waterflood is advisable. Economic evaluation of several well density scenarios should determine the optimum well density.

Increased environmental concerns about injection wellbore integrity (i.e., corroded casing that may not have cement behind the pipe), the cost of laying new production flowlines in addition to injection lines, and the cost of moving pumping units and their electrical service support drilling new injection wells instead of converting old producers, whenever possible.

**Waterflood Pattern Selection**

As stated earlier, heterogeneous reservoirs, especially those of fairly low permeability, have not responded well to non-pattern waterflooding. The low injectivity of these heterogeneous formations will not allow injection to keep up with current withdrawals, let alone to fill in and repressurize the reservoir from previous production. Even fields with injection schemes that had interior injection such as a line of injectors for every three lines of producers has failed to effectively waterflood the field.\textsuperscript{6,20} Eventually, most waterfloods have ended up on some form of repeating waterflood pattern.

Patterns that have a producer-to-injector ratio of one have been the most popular. The equal distances between injection wells and producing wells and the ability to provide sufficient injection have led to the success of 5-spot and line drive patterns. Inverted 9-spot patterns, with their three-to-one producer to injector ratio and half of the wells spaced only 70\% as far away from the injector as the other wells, have not proven to work as well in heterogeneous carbonate reservoirs.

Orientation of waterflood patterns can be critical if there is a preferential permeability direction, natural fracturing, or a combination of in-situ stresses and rock properties that would cause the formation to fracture in a particular direction during stimulation or injection above parting pressure. In old waterfloods, production data may give insights into this. Otherwise, acoustic anisotropy tests on oriented whole core samples may be the only source of insight into how one should orient the waterflood patterns.

**Well Completions**

All wells, both production wells and injection wells, must be completed in all of the hydrocarbon productive rock. In many old fields, the wells were perforated only in the highest porosity streaks (which presumably had the highest permeability). Often, these completions were planned without comparing them to offset wells. When waterflooding was started, no attention was paid to which zones were open. Years later, when integrated study teams built cross sections through all of the wells, completion interval inconsistencies from well to well became apparent.\textsuperscript{11} Well recompletion and infill drilling projects have confirmed the existence of bypassed oil.\textsuperscript{5}

Compounding the inconsistencies in completion intervals is the notion that water injected into these stratified reservoirs will spread out vertically and contact more of reservoir than was originally perforated. This is not always the case. Thin shale streaks and dense/tight streaks, which are often too thin to significantly affect log response (and are therefore not identifiable on logs), can act as horizontal baffles in the reservoir and thereby impede vertical flow.

Once injection has been established in a wellbore, it may be difficult to effectively open and stimulate new intervals,
due mostly to relative permeability effects (i.e., the aqueous stimulation fluids tend to enter the high water saturation zones caused by the water injection and, therefore, not enter and stimulate the newly opened zones). Another factor in early initial completions was the desire to make water-free completions. However, waterfloods produce water. Therefore, why not open up a zone that will make oil at a 50% watercut when the field is at an even higher watercut? There is a large volume of oil between the point of water-free oil production and 100% water production. The only caution is in having injection wells completed too close to water. The potential for lost injection into the aquifer is significant.

The moral of the story is that successful waterflooding of the entire pay is contingent on having all of the pay open and stimulated.

**Producing Well Operations**

Most if not all producing wells in waterfloods should be on artificial lift. Other than the ratio of drainage radius to effective wellbore radius (which can be altered by reducing well spacing and wellbore stimulation), the only term in Darcy’s Law that we can improve is the pressure inside the wellbore ($P_{well\: flowing}$), which is accomplished through the use of artificial lift. Keeping wells pumped off will make $P_{well\: flowing}$ nearly zero, and therefore, production will be maximized. If a well is not pumped off, not only will production decrease with lower pressure zones ceasing to produce (killing sweep efficiency), but crossflow can occur, which hurts production even more. If the crossflow is from a high watercut zone into a low watercut zone, relative permeability damage can occur.

The selection and proper sizing of artificial lift equipment has been greatly simplified through the development of a number of computer programs. But more important is the development of well management systems that optimize the operation of wells. Pump-off controllers do not allow pumping units to operate when the wells have insufficient fluid left to pump, which wastes energy and contributes to sucker rod failures. The more sophisticated designs also provide diagnostic information for the engineer. Solar/battery operated remote transmission units (RTU’s) can be hooked up to pumping units to alert field personnel of pumping system failures. The automation of oilfields with computerized supervisory-control and data-acquisition systems has been shown to significantly improve the profitability of oilfield operations.

**Injection Well Operations**

On the injection well side, flow and pressure measurement equipment can be tied into computer monitoring systems many miles away by the use of solar/battery operated remote transmission units (RTU’s). This permits accurate tracking of injection volumes and surface injection pressures.

The main objective of operating an individual injection well is to inject the maximum amount of water without having it go out of the intended pay zone. The first part requires that water be injected at the highest pressure possible. The second part limits the injection pressure to just below formation parting pressure. In practice, operators commonly use a surface injection pressure of 50 psig below formation parting pressure minus the static pressure of a column of injection fluid.

**Injection Water Quality**

Injecting water that is laden with oil and/or suspended solids equals one thing: a plugged up injection wellbore that is incapable of taking the maximum amount of water. Therefore, clean injection water is imperative.

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 4) bacteria in the system that can cause corrosion and suspended solids. Patton has written a book that is an excellent treatise on all aspects of water associated with the production of petroleum. He has summarized many of these issues in his SPE Distinguished Author Series paper.

Cleanup of injection water can be accomplished either by filtration or by providing sufficient settling time for solids and oil breakthrough. Research by Amoco Production Company that shows that standard tanks, with or without internal baffles, provide only a fraction of the theoretical retention time due to the water channeling directly from the tank inlet to the tank outlet. They have designed and patented a vortex settling tank system that significantly improves this retention time efficiency. Cleanup of injection water and remediation of the clogged wellbores provided significant improvement in west Texas and in Alaskan North Slope.

Many operators worry about the chemical compatibility of injected water with formation water. They fear that the formation will become plugged if scale precipitates in the formation. Patton dispels this concern by pointing out that there is very little contact between injection water and formation water in the reservoir.

However, the problem of scale precipitation in the producing wellbore persists. In carbonate systems, especially where anhydrite or gypsum is present, the injected water will dissolve minerals as it moves through the formation until it reaches saturation, and then it will precipitate scale as pressure drops in the wellbore. The only effective solution to this problem is to squeeze scale inhibitor into the formation periodically, but these treatments can be expensive.

To avoid both scale problems and the high cost of inhibitors, many operators use fresh water for their make-up water. But we have seen that there isn’t a problem in the formation, and fresh water doesn’t necessarily solve the problem in the wellbore. Brackish water used as make-up water with a split injection system can be a better alternative to the use of fresh water which is needed for human consumption and irrigation.
The injection system itself is a third location of concern for scale formation. Tanks, injection pumps, and injection lines are subject to scaling if make-up water and produced water have scaling tendencies and are mixed prior to injection. Splitting the injection system is the best solution for preventing scale precipitation in surface injection facilities. Having a tank and pump system for both make-up water and produced water avoids mixing the incompatible waters. The changing volumes of produced and make-up water can be balanced by using an injection flowline manifold constructed so that either produced or make-up water can be selected for each well.

**Waterflood Operations Using Injection Well Testing**

Because waterflooding is recovery of oil by means of water injection, it follows that management of the waterflood project should have management of the injection wells as its primary focus. Kelm and Robertson\(^{28}\) proposed a waterflood management scheme using periodic injection well testing as the main management tool. They contend that by running step rate tests to determine the current formation parting pressure, temperature surveys and radioactive tracer surveys to determine injection profiles, and pressure falloff tests to determine skin factor, fracture half length, and reservoir pressure, the injection --and therefore waterflood performance-- could be optimized.

One of the toughest and often most ignored facets of waterflooding is injection conformance. The question is, is the injection water going where it should (vertical distribution) in the injection well? Measurement of injection conformance can be done with radioactive tracer surveys,\(^{28, 29}\) temperature surveys,\(^{28}\) and production logging (spinner surveys).\(^{30}\) Injection conformance has also been measured using oxygen activation logging.\(^{31, 32}\) Three dimensional reservoir simulation that incorporates the data from injection profiles can greatly aid in understanding a waterflood’s performance.\(^{30}\)

While measuring a well’s injection profile is an established practice, rectifying an injection well’s conformance is another matter. The use of cement, micro-particles, foams, polymers, selective completions, and multiple packer completions have all been used with varying success.\(^{33, 35}\) The success or failure of the profile modification workover is often dependent on the mechanical condition of the wellbore and its effects on properly placing the diverter. Corrosive injection water, especially if it contains H\(_2\)S, will destroy the injection well’s casing below the packer. Some operators are installing corrosion resistant casing (duplex stainless steel, fiberglass, etc.) across injection well completion intervals to combat this problem.

**Waterflood Surveillance**

The successful management of any waterflood project, especially in stratified/heterogeneous reservoirs, relies heavily on knowing what is going on in every well in the field; i.e., surveillance. Every waterflooded project has its own unique situation. However, development of surveillance programs are well documented.\(^{33, 34, 35}\) There are two very good SPE Distinguished Author Series papers that outline the basic considerations necessary for successful design of a surveillance program, one by Thakur\(^{36}\) and the other by Talash.\(^{37}\)

The key ingredient of any surveillance program is accurate data collection. The accuracy and frequency of the data collected limit a waterflood management system.\(^{9}\) Time and time again, we have conducted reservoir studies using data that were sparse, inaccurate, or non-existent.

The most basic data are production volumes. Monthly testing of each producing well is essential, preferably for a minimum of 24 hours using a three-phase separator. Many operators just take occasional tests using a two-phase separator, measuring only the total liquid production, estimating the oil and water percentages from a sample or sightglass, and not measuring the gas production -- all at pressure conditions that can be significantly different from those at the tank battery. These tests must then be used to allocate the total field back to each well. It is obvious that this leads to a very inaccurate picture of gas-oil ratio performance, locations of water breakthrough, injection-withdrawal ratios for an injection pattern, and most importantly, sources of oil production.

Almost as important is collection of water injection volumes and surface injection pressures. Valuable insights into the performance of the waterflood can be gained from individual well plots of injection rate versus time, injection pressure versus time, Hall Plots (cumulative wellhead pressure * time vs. cumulative injection),\(^{38}\) pattern injection-withdrawal ratio plots, and total property injection-withdrawal ratio plots.

The advent of high-speed personal computers with large memory capacities has greatly facilitated automating waterflood project surveillance. All manners of production and injection data can be imported into spreadsheets or a relational database.\(^{39}\) There are systems available by which the field personnel input production measurements (such as raw tank fluid levels) into an electronic notepad, return to the office, plug the notepad into a computer, press a button, and the data is automatically uploaded, the necessary calculations performed, and the results transferred into the company’s production data and accounting systems. This eliminates hours of hand calculations, the time lag of routing paper from office to office, multiple people hand inputting data, and the multiple opportunities for errors. Once the historical data is imported, updated plots and reports can be easily generated with each monthly update of the production and injection data. This way, large volumes of data can be processed, put into useable formats, and reviewed in a very short time with very little effort.

The downside of being able to process data quickly is that the results are only as good as the input data. For example, injection water volumes measured by orifice meters, where the orifice plate has been eroded from a perfectly square-edged circular hole to a rounded-edged hole of indescribable shape and unknown area, are totally worthless. In short,
measurement equipment must be maintained and used properly, and measurements must be taken at proper frequencies.

High powered PC’s and workstations and commercially available 3-D finite difference reservoir simulation software have provided even the smallest independent operator with another powerful reservoir management tool: full-field reservoir simulation. Full-field simulations can locate bypassed oil, identify viable (and uneconomic) drilling locations, simulate changes in operations, and simulate changes in waterflood pattern alignment.

The time, effort, and expense of developing a reservoir model are easily justified by the money saved if foreseeable development mistakes are avoided, or if operations can be improved through reservoir simulation. Qualified petroleum engineering consultants can perform reservoir simulation studies cost effectively, if an operator does not have the in-house expertise to build the reservoir model.

Conclusions
Successful implementation and operation of a waterflood project, even in complex heterogeneous formations, is a matter of executing a well-conceived comprehensive plan, none of the elements of which are “rocket science.”

Acknowledgments
The industry’s body of knowledge of waterflooding extends well beyond that which has been reported in the literature. The ideas, successes and failures of countless engineers, geologists and field personnel have all combined to progress waterflooding technology to its current state of maturity.

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References


