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Screening guidelines and data analysis for the application of in-situ polymer gels for injection well conformance improvement

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SCREENING GUIDELINES AND DATA ANALYSIS FOR THE APPLICATION OF IN-SITU POLYMER GELS FOR INJECTION WELL CONFORMANCE IMPROVEMENT

by

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In the first section, the problem of excessive water production, some fundamentals of conformance engineering, and study objectives are presented. The major study findings, conclusions, and future work recommendations are summarized in the second section.

ABSTRACT

Excessive water production represents a major industry challenge because of its serious economic and environmental impacts. Polymer gels have been effectively applied to mitigate water production and extend the productive lives of mature oilfields. However, selecting a proper gel technology for a given reservoir is a challenging task for reservoir engineers because of the associated geological and technical complexities and the absence of efficient screening tools.

A comprehensive review for the worldwide gel field projects was conducted to develop an integrated systematic methodology that determines the applicability of three injection well gel technologies including bulk gels, colloidal dispersion gels, and weak gels. Comparative analysis, statistical methods, and a machine learning technique were utilized to develop a conformance agent selection advisor that consists of a standardized selection system, conventional screening criteria, and advanced screening models.

The results indicated that gel technology selection is a two-step process that starts by matching problem characteristics with gel technical specifications and mechanisms. Then, the initial candidate technology is confirmed by screening criteria to ensure gel compatibility with reservoir conditions. The most influential conformance problem characteristics in the matching process are channeling strength, volume of problem zone, problem development status, and the existence of crossflow. In addition to crossflow, the presence of high oil saturations or unswept regions in the offending zones requires the application of flood-size treating technologies that combine both displacement and diversion mechanisms. The selection and design of gel technologies for a given conformance problem greatly depend on the timing of the gel treatment in the flood life.

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1. INTRODUCTION

1.1. PROBLEM STATEMENT AND SIGNIFICANCE

Excessive water production represents a major industry challenge because of its serious economic and environmental impacts. The problem of producing and disposing of large quantities of injection water is becoming more crucial due to the tightening economic constraints caused by the falling oil prices. In addition, water production is continuing to have high rates in mature oilfields despite the great attention that is paid by oil and gas companies toward water management practices.

By way of illustration, the 2015 report of Veil Environmental Company shows that in 2012, the U.S. oilfields produced about 21.2 billion barrels water versus only 2.26 billion barrels oil. This implies that the national water-oil-ratio in the U.S. oilfields is about 9.2. This report also illustrates that the U.S. produced water volumes in 2012 are comparable to the 2007 estimates (21 billion barrels), as shown in Figure 1.1. Regarding water management practices, the report illustrates that about 38.9% of these 21.2 billion barrels of water is injected into disposal wells in a non-commercial way. If it is assumed that the average transporting and pumping cost is $1.00 per barrel, then the total cost of disposing the above percent of the produced water (i.e., 38.9%) is about 8.25 billion dollars per year. McCurdy (2011) provided that the average disposal cost of one barrel water is $0.25 and its transportation cost is $1.00 per hour.

Evidently, the above production statistics reveal that there is a persistent need to plan and conduct more efficient water control treatments with optimized designs to keep these tremendous water quantities in petroleum reservoirs and improve oil recovery. The first step toward meeting this need is the identification of the best suited solution from the many conformance improvement technologies and operations.

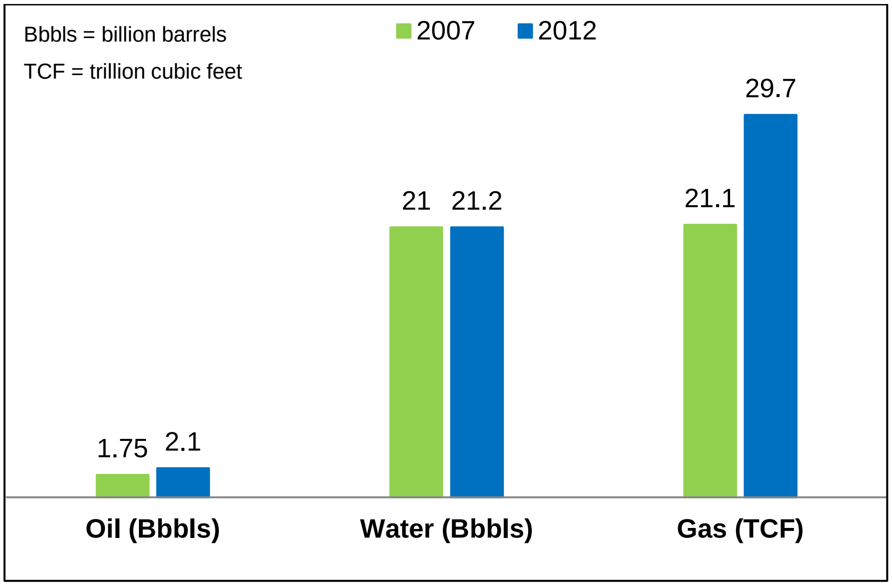


Figure 1.1. U.S. Oil, Water, and Gas Production in 2007 and 2012 (Veil Environmental, LLC, 2015)

Controlling water flow during oil production has always been the objective of the oil and gas industry. It is considered that much of and probably the majority of produced water results from conformance problems that existed because of reservoir heterogeneity and unfavorable mobility ratio (Sydansk and Romero-Zeron, 2011). Excessive water production usually leads to early abandonment for production wells and large bypassed oil reserves. Polymer gels have been proven to be effective in addressing this problem and in increasing oil recovery. They are increasingly applied to improve the volumetric sweep efficiency of different improved oil recovery (IOR) or enhanced oil recovery

(EOR) flooding processes. Polymer gels effectively block the offending high conductive zones and provide a sustainable diversion of the subsequent injected water toward unswept low permeability zones. Such remediation would mitigate water production and enable recovery of bypassed oil reserves in a cost-effective way and thus extend the productive life of mature oilfields. Normally, it is preferable to address the problem at its source, which in the case of IOR/EOR floodings is the injection well. This would provide more efficient conformance improvement treatments that last longer and impact a larger portion of the reservoir (Lantz and Muniz, 2014).

Remarkably, the selection of a proper polymer gel technology for a given reservoir is a challenging task for oilfield operators and reservoir engineers. This is fundamentally due to the existence of numerous types of conformance problems that may exist anywhere from the wellbore to deeply in the reservoir. Polymer gels also have a wide range of forms and chemistries that function by different mechanisms to improve the sweep efficiency of IOR/EOR processes. The selection process is further complicated by the fact that the treatment of a specific conformance issue requires a distinct gel technology. Furthermore, conformance problem properties are qualitatively evaluated using several diagnosing techniques along with the traditional geological and reservoir characterization. The subjective nature of this evaluation imposes an intuitive judgment on the selection of gel technologies. Finally, despite the large number of implemented gel field projects, there is an obvious shortage in the number and quality of screening studies for polymer gels, especially the advanced screening models.

1.2. RESEARCH OBJECTIVE AND WORK SCOPE

This study aims to develop an integrated systematic methodology that determines the applicability of injection well polymer gel technologies. Specifically, the main objective of this study is to develop comprehensive, updated, improved applicability guidelines for three gel systems based on their field applications in injection wells. This objective includes the following three sub-objectives:

a. Recognition of how polymer gels should be identified and what are the influential parameters in their selection process.
b. Establishment of conventional screening criteria using quantitative screening parameters.
c. Development of a generalized selection system using qualitative matching parameters.
d. Development of advanced screening models using a machine learning technique.

This study provides a better understanding of a gel technology selection process and indicates the role of each step or parameter in this process. This would help reservoir engineers in the identification of the most appropriate treating agent using a standardized selection system and advanced screening models. The ability to rate conformance problems and gel technologies would considerably reduce the role of the costly diagnosing techniques of conformance problems. It will also assist field engineers in identifying a combination of treating agents in the case of reservoirs that exhibit various heterogeneity forms. In such situations, advanced screening models will help in ranking of gel systems by means of a score factor. Finally, providing new insights about how polymer gels should be identified and designed will be very beneficial in increasing gel treatments success rate.

A specialized database was constructed using the data of gel field applications published in the public domain, especially SPE papers and U.S. Department of Energy reports. Based on a comprehensive review of conformance engineering considerations, technical specifications of gel technologies, and reviewed case histories, the steps and parameters of the gel identification process were inferred. Statistical techniques were utilized to estimate missing data, detect potential outliers, and summarize the conventional screening criteria. Comprehensive comparative analyses of matching parameters were performed to classify conformance problems and to identify their parameter validity limits for each gel system. Machine learning techniques were used to impute missing data points and develop advanced screening models.

The above tasks and the study results were described and presented in detail in three published conference papers:

1. In the first paper, features of polymer gels data were indicated and data problems such as missing and outlier data points were treated using several methods and approaches. Parameters that are necessary to be considered in order to develop an integrated selection system for conformance technologies were identified. In addition, 13 quantitative parameters and three production-related aspects were utilized to establish complete traditional screening criteria. Furthermore, screening parameters were compared for different gel technologies to detect differences and their relative importance for each particular treating agent. Finally, some dual-treating agent case histories were verified to demonstrate the

ability of new screening criteria to nominate the most suitable gel technologies for multiple heterogeneity reservoirs.

2. In the second paper, reservoir and fluids characteristics, diagnosis indicators used in the evaluation of drive-fluid channeling strength, and gel treatment operational parameters were summarized. Then, problem zone volumes were estimated using a design rule of thumb and the problem development status was indicated using some production-related parameters. Comprehensive review was performed to recognize the steps of the gel selection process and the most influential problem characteristics. Finally, all characteristics of conformance problems were compared for different gel systems to facilitate the classification of conformance problems and the identification of distinct validity limits for each gel technology.
3. In the third paper, a comprehensive review of machine learning and pattern recognition techniques was first conducted. The goal of this review was to identify the most suitable supervised classification technique that can handle the variety of parameters utilized in the rating of polymer gels. After data processing, treatment of potential outliers, and imputation of missing values some variables were categorized in order to treat data gaps within independent variables. The most discriminating variables were distinguished using several techniques and considerations. To consider the regional tendencies in the application of polymer gels, three probabilistic models were developed that include different numbers of gel technologies. Furthermore, to meet the new developments in the application of some gel systems, a variant model without the treatment timing indicator (water cut) was constructed for each main classifier. The accuracy of the constructed

classification models were checked using three global predictivity measures. A prediction profiler was also used to visually monitor performances of the classifiers, and certain tendencies were identified by the investigation of the mispredicted projects.

2. LITERATURE REVIEW

This section reviews oilfield conformance problems, conformance improvement techniques, polymer gel technologies, and principles of EOR technical screening. A critical review of previous polymer gels applicability evaluation studies will also be presented to highlight the current gaps and limitations in the literature.

2.1. OIL RECOVERY AND RESERVOIR CONFORMANCE

Petroleum reservoirs produce hydrocarbons by means of a wide variety of drive mechanisms. They are generally categorized into three types or stages: primary, secondary, and tertiary or enhanced oil recovery methods (EOR). For conventional oil reservoirs, reservoir natural energy (reservoir pressure) significantly reduces after the primary recovery as a result of oil and gas production. Therefore, several materials are injected to supply reservoir energy, displace oil toward production wells, and create favorable conditions for oil recovery in the case of EOR methods as shown in Figure 2.1. It is usually referred to such injection processes with displacement objectives as oil recovery flooding or process and to the injected materials as drive-fluids.

If these materials already existed in the reservoir such as water and natural gas, the flooding process is termed as secondary recovery such as waterflooding. Otherwise, if injected materials are not normally presented in the reservoir such as steam, polymer, and CO_2, they are termed as tertiary or EOR processes or floodings. Improved oil recovery (IOR) is used to describe any practice or process that increases oil production or recovery including secondary and EOR floodings (Sydansk and Romero-Zeron, 2011). It also includes other well-operational techniques like hydraulic fracturing, horizontal wells, and infill drilling.

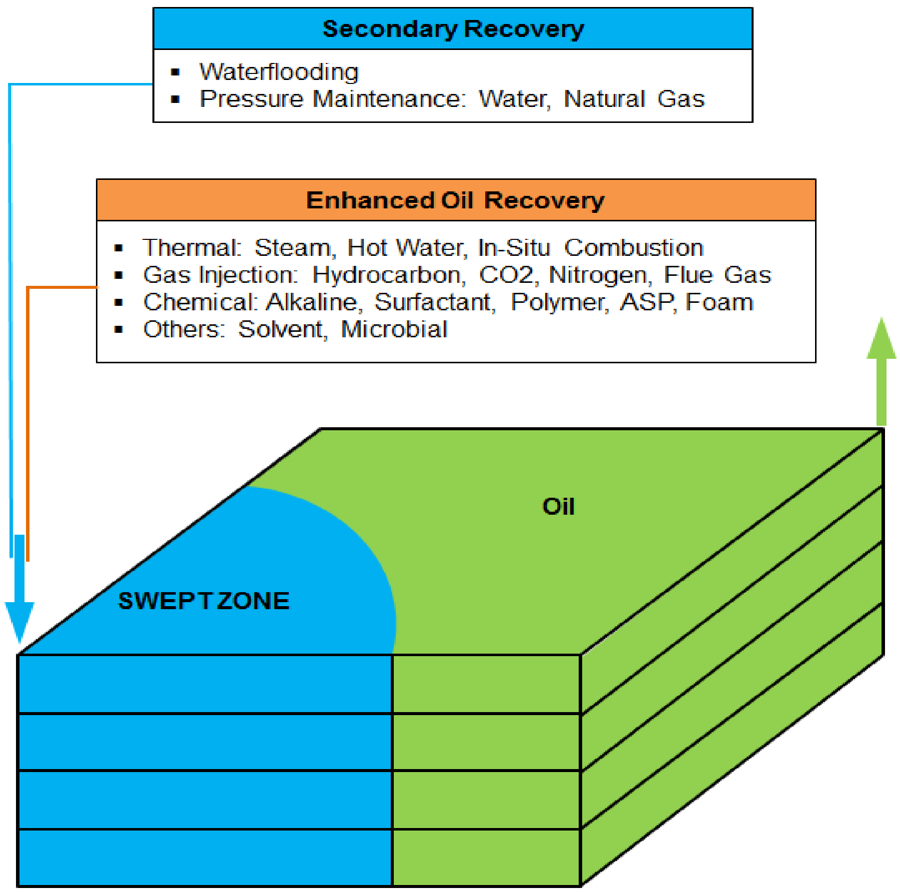


Figure 2.1. Ideally Swept Pattern with Stable Displacement and Even Injection Profiles

For any secondary or tertiary recovery method, the overall recovery efficiency (RF) is a product of two efficiency factors as given by the following generalized expression (Ahmed, 2006):

$$RF = E_D * E_I \quad (1)$$

Where E_D is the microscopic displacement efficiency and E_I is the volumetric sweep efficiency of a flooding process. This formula indicates that to increase oil recovery from an oil reservoir, it is necessary to improve either one of these efficiencies or both in a cost-effective way.

The microscopic displacement efficiency (E_D) is the fraction of the moveable oil that has been displaced from the swept zone at any given time or pore volume of injected fluids (Ahmed, 2006). This efficiency is affected by the presence of surface tension and interfacial tension, capillary forces, and rock wettability. Thus, it can be improved by injecting some materials that target the above rocks and fluids physical properties such as surfactants, CO_2, alkaline, and many other materials (Green and Willhite, 1998).

The volumetric sweep efficiency (E_I) is the fraction or percent of the pattern pore volume that is swept by the displacing fluid. It is also a combination of two components: areal (E_A) and vertical (E_V) efficiencies. In the oil and gas industry, *conformance* is used as a measure of the volumetric sweep efficiency of IOR/EOR floodings being conducted in a reservoir (Sydansk and Romero-Zeron, 2011). Specifically, reservoir conformance is a measure of the areal and vertical uniformity of the flood front as it is being propagated through a reservoir (PetroWiki, 2016).

Some physical and geological reasons that are related to reservoir rocks and fluids significantly impair the volumetric sweep efficiency of reservoir floodings. From an IOR/EOR prospect, they cause non-uniform areal flood fronts and disproportionate vertical injection profiles for drive-fluids during the flooding process as shown in Figure 2.2. Consequently, they result in early water breakthroughs, low oil recoveries, large bypassed oil reserves in the unswept zones, and undesired excessive water production and cycling. Generally, issues that negatively impact the sweep efficiency of flooding processes are called conformance problems and technologies that are used to address them are termed as conformance solutions or treatments. In addition, the physical and geological reasons are called roots of conformance problems and include reservoir heterogeneity and unfavorable mobility ratio. Conformance problems broadly encompass any issue that causes the injection water (or any drive-fluid) to avoid the displacement of oil and to directly compete with and impair oil production from a reservoir (Sydansk and Romero-Zeron, 2011). Thus, it is interchangeably referred to conformance problems as excess water production problems. Furthermore, the term *conformance* is also used to indicate the treatment of or as a measure of excessive water production for petroleum reservoirs.

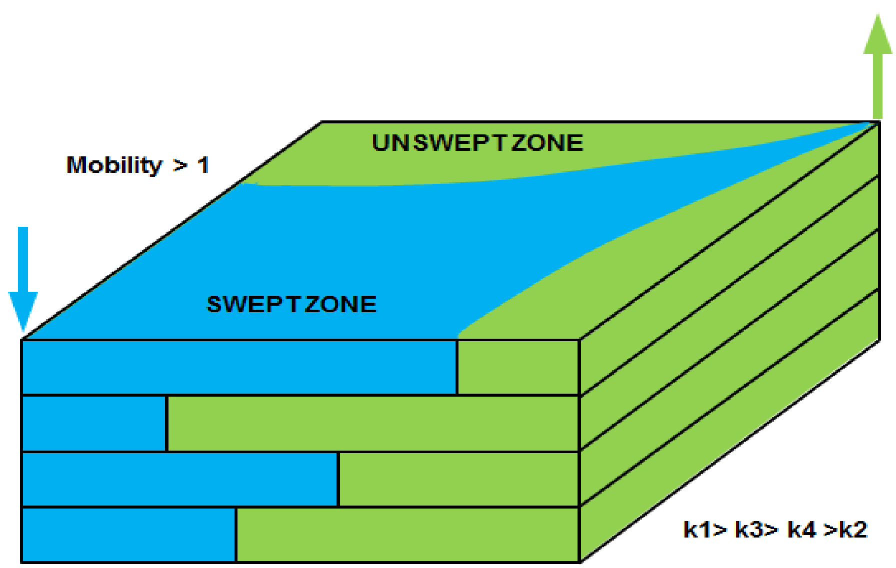


Figure 2.2. Poorly Swept Pattern with Non-Uniform Flood Front and Injection Profiles

2.2. EXCESSIVE WATER PRODUCTION

When an oilfield with poor conformance reservoir enters the mature stage after a certain time of flooding process, oil production significantly decreases and water reaches its ultimate production rates. This occurs because water flows from injection wells toward production wells in separate flow lines or pathways from oil due to the presence of substantial conformance problems. This would result in poor sweep efficient for the flooding process and large left-behind oil quantities in the unswept zones. As the injection process continues, water injection would not help in recovering any additional oil and produced water is either re-injected or disposed.

In this stage, many production wells are abandoned as they reach the economic limit. In addition, oil production expenses are significantly increased due to the associated lifting, handling, treatment, environmental-related, and disposal costs. Therefore, excessive water production considerably hinders not only the technical feasibility, but also the economic feasibility of IOR/EOR processes. In such cases, the mitigation of water production by improving the sweep efficiency of IOR/EOR floodings would greatly help in increasing oil production, recovery of bypassed oil reserves, and extend the productive life of mature oilfields. In addition, it would reduce oil production expenses and environmental liabilities.

2.3. CONFORMANCE PROBLEM TYPES

Undesired water production is caused by a broad range of conformance issues that have different roots and forms or configurations. The roots of most conformance problems are principally the contrasts in three reservoir rock and fluid properties: density, viscosity, and permeability. All these contrasts cause the injected drive-fluid to independently flows to production wells and avoid the displacement of oil as mentioned earlier (Figure 2.3). Some other conformance issues that take place in the wellbore such as casing leaks and channeling behind pipe result from tubular mechanical and completion problems.

The shape of the flood front can significantly be distorted by the gravity segregation or viscous fingering. These phenomena occur if there is a striking contrast in density or viscosity between the injected and reservoir fluids. Conformance issues that are caused by the contrast in fluid properties are also called mobility problems. Reservoir permeability contrast (heterogeneity) greatly impacts distributions of drive-fluids because high flow capacity zones would take a large portion of the injected fluid. In contrast, low flow capacity zones receive small volumes of drive-fluids and thus, they are partially swept from the oil. Drive-fluid distribution here refers to either injection or production profiles of water and oil. Numerous types of reservoir permeability heterogeneity–related conformance problems are existed as the permeability spatial variation occurs in various forms and directions as it will be illustrated in the next paragraphs. The severity of a conformance issue of a certain root is exacerbated by the presence of other problem roots.

Generally, conformance issues are categorized with respect to many aspects such as problem roots, location relative to wellbore, direction of flood front distortion, well type, the presence of crossflow, the nature of flow system whether it is a matrix-rock or a high permeability anomaly (linear vs. radial), and the solution type (Azari and Soliman 1996; Seright et al. 2001; Smith and Ott, 2006; Joseph and Ajienka 2010). They can be either areal or vertical issues based on the direction in which the flood front is being distorted (Figure 2.4). In addition, they are classified as wellbore, near-wellbore, and far-wellbore problems according to where they affect flow profiles or where they can be controlled as it will be illustrated later.

In the following sections, typical oilfield conformance issues will be presented and briefly discussed. They are ordered in terms of their effect location and treatment difficulty using currently available conformance improvement technologies that will be presented later (Seright et al. 2001; Sydansk and Romero-Zeron, 2011; Bai, 2014).

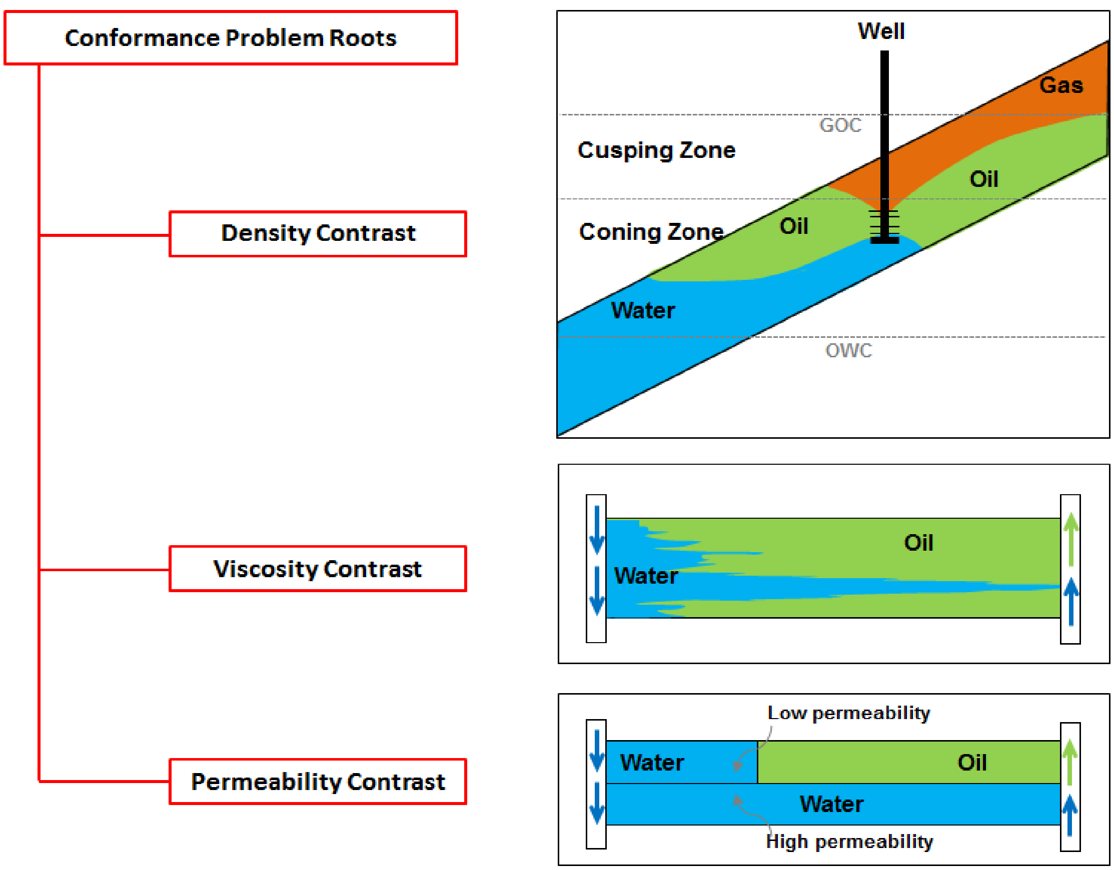


Figure 2.3. Conformance Problems Roots and Examples

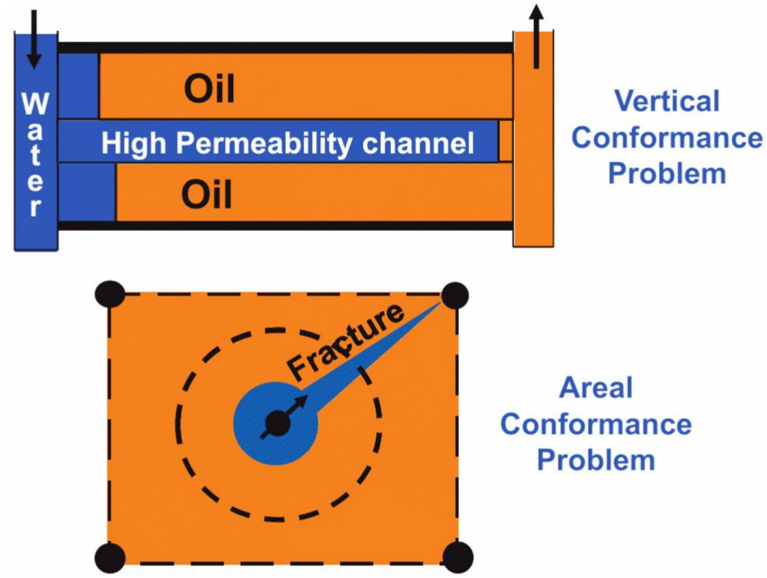


Figure 2.4. Vertical and Areal Conformance Problems (Sydansk and Romero-Zeron, 2011)

2.3.1. Wellbore Problems. As their names imply, these conformance issues exist in wellbores of production wells and represent vertical conformance problems. They result usually from tubular mechanical and completion problems. Generally, this type of conformance problem includes the following two issues.

2.3.1.1. Water channeling behind pipe. Figure 2.5 (a) illustrates that the unwanted water is flowing into the wellbore through a channel exists between wellbore casing and the sand face of a water-bearing layer. The root of this conformance issue is totally related to the quantity and quality of the placed cement behind the casing against the water zones. Field experience shows that this issue can easily be treated using polymer gel or cement squeeze depending on whether the flow aperture is less or greater than 1 mm.

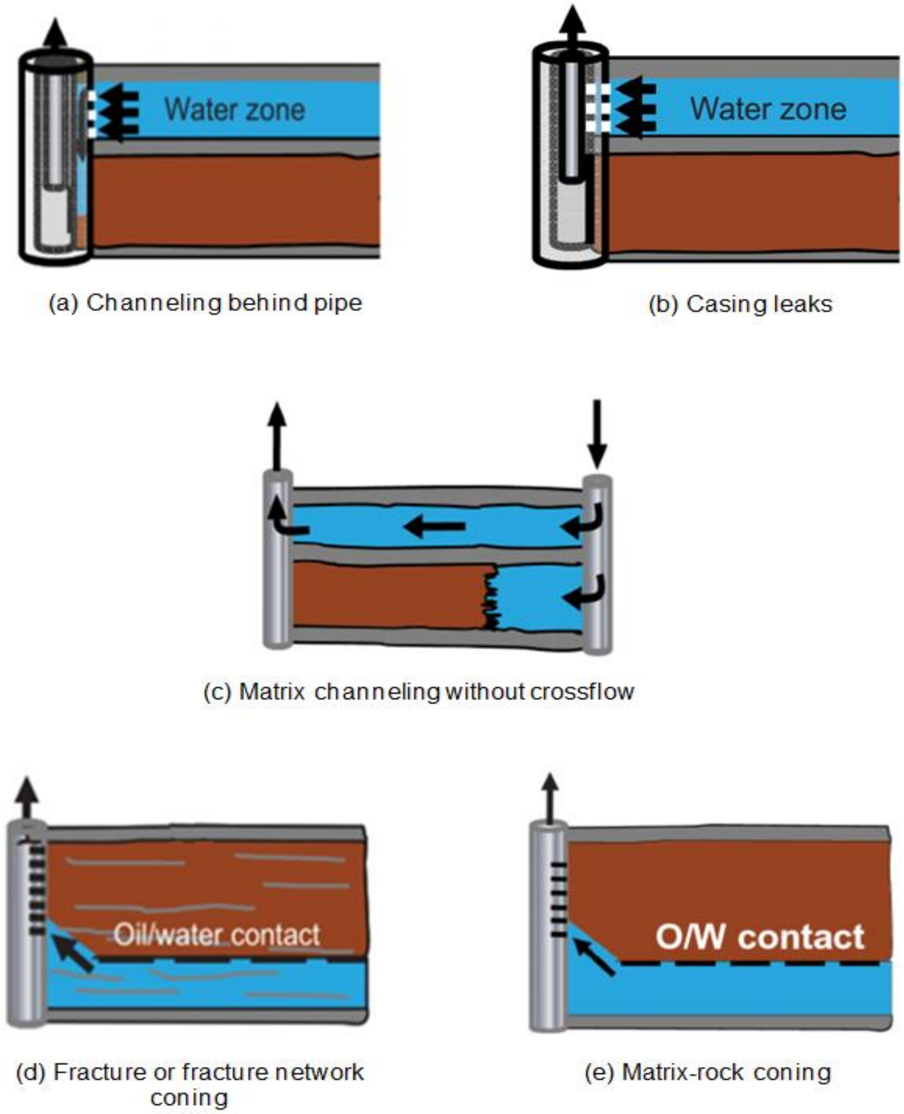


Figure 2.5. Wellbore and Near-Wellbore Conformance Problems (Sydansk and Romero-Zero, 2011)

2.3.1.2. Casing leaks. In this case, corrosion or thread failures in the wellbore casing body or coupling joints provide a pathway for water to flow from one layer into the wellbore (Figure 2.5 (b)). Practically, this issue is challenging to be successfully treated despite the variety of conformance solutions that can be applied such as tubing patches, straddle packers, polymer gels, resins, and cement squeeze.

2.3.2. Near-Wellbore Problems. This type of conformance issue includes four vertical problems that are treated in the near-wellbore region if possible.

2.3.2.1. High-permeability matrix-rock strata without crossflow. This issue represents a vertical conformance problem in which the undesired water flows in a separate high permeability matrix-rock strata or zones that are not in pressure communication with oil zones (Figure 2.5 (c)). This refers to the presence of a continuous impermeable shale barrier between water and oil zones that have substantial permeability contrast. This problem is considered easy to be treated, and there is a wide range of conformance solutions that can be applied such as well completion techniques, mechanical techniques, and permeability-reducing agents.

2.3.2.2. Water coning through fractures. The presence of vertical fractures or other high permeability anomalies in the near-wellbore region causes the water to cone up the wellbore from an aquifer (Figure 2.5 (d)). Similarly, these permeability heterogeneities can cause the gas to cone down the wellbore form a gas cap. Polymer gels have been easily and successfully applied to treat fracture-type water coning and the effectiveness of gel treatment greatly increases with increasing injected gel volumes.

2.3.2.3. Water coning through matrix rock. The configuration of this problem is similar to the previous coning issue as shown in Figure 2.5 (e). The difference here is that water flows from an underlying aquifer into a vertical well wellbore through a matrix-rock reservoir. High fluid flow rates and substantial pressure drops in this region considerably accelerate the problem occurrence rate. It has been provided that it is difficult, if not impossible, to implement a long-term solution for this type of coning problem (Sydansk and Romero-Zeron, 2011). The difficulty arises from the need to place a disk-shaped permeability barrier radially away from the wellbore, which practically is difficult to be performed especially using the injectable chemical conformance agents.

2.3.2.4. Water cusping through matrix rock. When water or gas flows through an inclined matrix-rock reservoir strata (Figure 2.3), water and gas coning issues are called cusping conformance problems. They are also difficult to treat that long-term remedies are obtained and polymer gel treatments have a low probability of success if applied. Seright (1988) provided that hydrocarbon productive zones must be protected during gelant placement.

2.3.3. Far-Wellbore Problems. These issues are also called reservoir-related conformance problems because they influence fluid flow pathways in a large portion of or the whole reservoir extent.

2.3.3.1. Mobility-induced viscous fingering. This fluid mobility-related issue represents an areal conformance problem that occurs when the drive-fluid displaces a relatively high viscosity oil. In this situation, viscous fingering is triggered by the considerable viscosity or mobility contrast exists between injected and reservoir fluids, as shown in Figure 2.3 and Figure 2.6 (a). Mobility–induced viscous fingering problems are usually aggravated by the permeability variation in heterogeneous reservoirs. They also may occur in the vertical direction in the cases of bottom water drive and gas cap expansion. The typical technology that has been extensively applied to overcome mobility issues is the polymer flooding. In this EOR process, different types of polymer are used for the purpose of increasing the viscosity of drive-fluid and thus, improving mobility ratio.

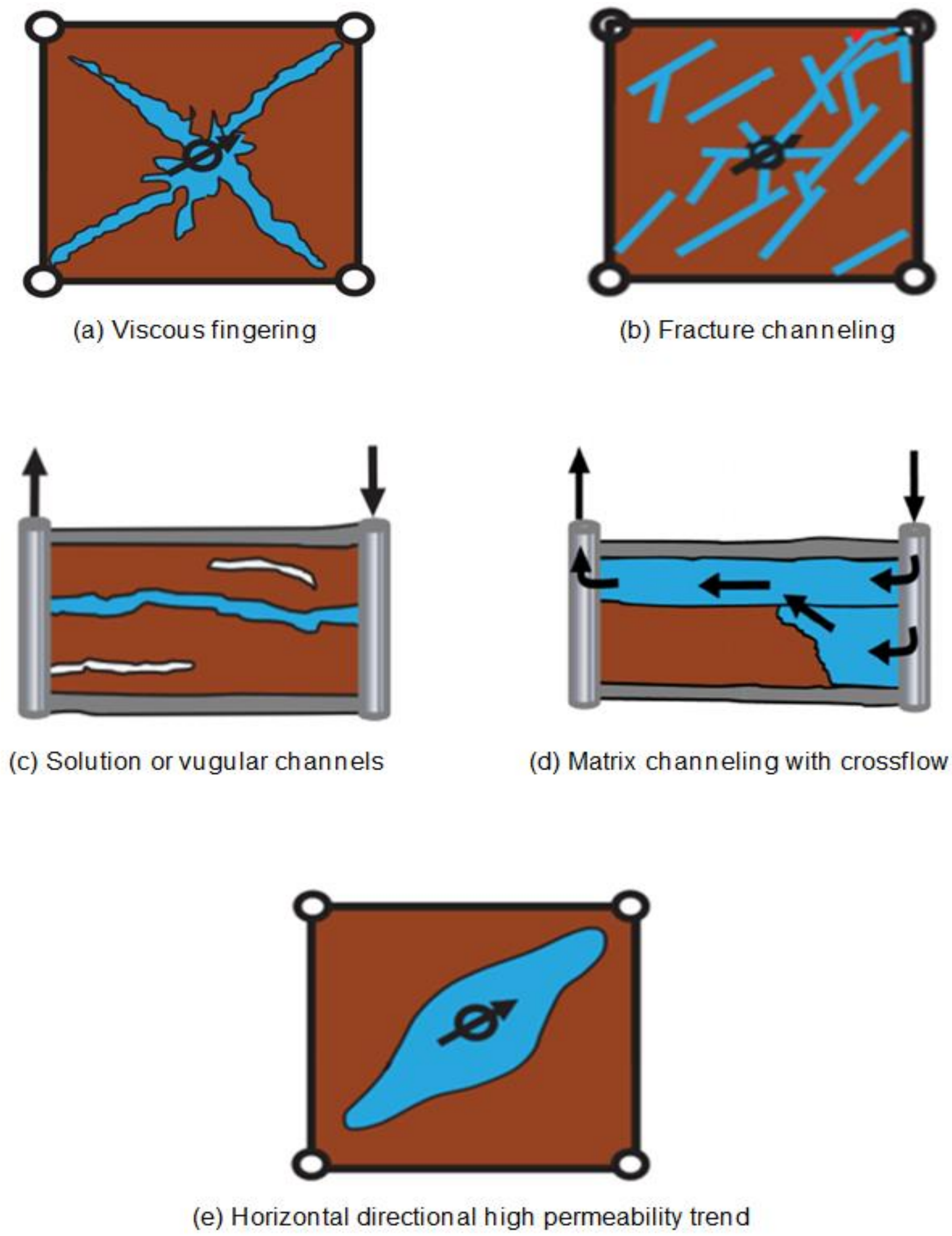


Figure 2.6. Far-Wellbore Reservoir Conformance Problems (Sydansk and Romero-Zero, 2011)

2.3.3.2. Fracture channeling. Probably, this issue is the most encountered conformance problem in oil and gas fields. It takes place when the drive-fluid flows in natural, induced, and hydraulic fractures and its severity greatly depends on fracture intensity and orientation (Figure 2.4 and Figure 2.6 (b)). This areal problem has been successfully and economically treated using polymer gels; however, treatment volumes in the range of several thousand barrels are required.

2.3.3.3. Solution channels and interconnected vuggy porosity. An areal and/or vertical conformance problem that usually presents in carbonate reservoirs (Figure 2.6 (c)). The root of problem is either the interconnected vuggy porosity or solution channels that are created during IOR/EOR floodings especially CO_2 floodings. Both solution channels and interconnected vuggy channels tend to have large diameters (0.5 mm). However, connected vugs represent a large volume problem that usually treated by foam-based technologies. As for fracture channeling, these issues are good candidates for polymer gels; however, they cause extremely severe channeling when they are exceptionally large volumes.

2.3.3.4. High-permeability matrix-rock strata with crossflow. The task of reducing water production from heterogeneous multilayered matrix-rock reservoirs would be further complicated by the presence of vertical pressure communication and fluid crossflow (Figure 2.6 (d)). The solution of this vertical problem requires the application of conformance technologies that can affect a large portion of the reservoir. Normally, such remedies involve injection of large volumes of treating agents such as polymer or in-depth-fluid diversion technologies (IFD) such as microgels. It has been provided that the required treatment volumes and placement technique make this problem difficult to remedy.

2.3.3.5. High-permeability matrix-rock directional trends. As shown in Figure 2.6 (e), an areally limited flood front is formed when there is a directional high matrix-rock permeability trend in the pattern or reservoir. If the wells are already in place, polymer flooding and IFD technologies are recommended if they can be deeply and selectively placed in the reservoir. Otherwise, areal realignment of wells and utilization of horizontal wells and advanced wellbore are more reliable to reduce water production.

2.3.3.6. Water production from a single layer. The production of water from a single oil-producing zone is considered the hardest conformance problem to be treated using currently available conformance improvement technologies (Bai, 2014). Any solution proposed for this problem must be perfectly selective in the remediation. This implies that the solution should be able to reduce water production and improve oil production or at least keep it unchanged. Certain polymers and weak gel systems have been found to reduce the relative permeability to water more than to oil and gas and thus, they have the required treatment selectivity feature. Such conformance systems are termed relative-permeability-modification (RPM) treatments and have been applied to production wells of matrix-rock reservoirs. Although these conformance chemicals seem to be a potential solution for this problem, Sydansk and Seright (2007) have provided that it is not recommended that RPM treatments applied in such situations. They attributed that to the reduction that might result in oil production after water saturation increases behind the placed treatment materials, as shown in Figure 2.7.

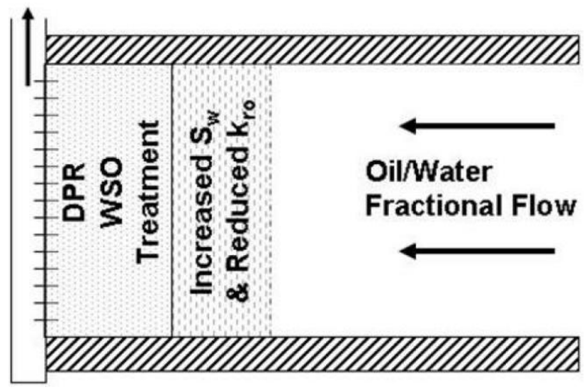


Figure 2.7. RPM Treatment of a Single Formation (Sydansk and Seright, 2006)

2.4. DIAGNOSIS OF CONFORMANCE PROBLEMS

The precise identification and characterization of conformance problems represent the first and most critical step in performing a successful water control remediation (Soliman et al. 2000; Seright et al. 2001; Reynolds and Kiker, 2003; Smith and Ott, 2006; Jaripatke and Dalrymple, 2010). Conformance Problem assessments are not essential only for selecting a proper treating technology, but also for the designing and implementing of conformance improvement treatments. The necessity of the sound understanding of a water production problem is emphasized by the fact that each conformance problem requires certain conformance improvement technologies. Field evaluations of conformance problems mainly concentrated on the identification of the water source and the characterization of the problem severity and extent.

A number of excellent references have addressed conformance issue diagnostic evaluations and techniques (Azari and Soliman, 1996; Pappas et al. 1996; Love et al. 1998; Seright et al. 2001; Smith and Ott, 2006; Jaripatke and Dalrymple, 2010; Sydansk and Romero-Zeron, 2011; Kim and Crespo, 2013).

The diagnosis of conformance problems often starts by the review of geological and reservoir characterization information. In this stage, it is essential to indicate whether a conformance problem is caused by spatial permeability heterogeneity or unfavorable mobility ratio in the case of IOR/EOR floodings. Secondly, the following key information sources are reviewed to recognize the nature (type) and severity of the water production problem (Jaripatke and Dalrymple, 2010):

- Reservoir characterization data
- Permeability profile and core analysis data
- Previous well logging analyses
- Injection history and injection profiles
- Production history and tests
- Recent survey results
- Well completion and integrity data

The above information sources are reviewed in a complementary way to specifically make the following key distinctions (Chou et al. 1994; Sydansk and Southwell, 2000; Seright et al. 2001):

- Is the water production issue an areal or vertical conformance problem?
- Is the water production issue a wellbore, near-wellbore, or reservoir related problem?
- Does the water issue involve matrix-rock or high-permeability anomaly? In other words, is the fluid flow pattern around the wellbore linear or radial?
- Does the water production issue involve pressure communication and vertical fluid crossflow?

Several diagnosing techniques are used to evaluate conformance problems that generally have different functions and objectives. Seright et al. (2001) have provided that there are probably 30 different diagnosing methods that should be integrated for a correct characterization of a conformance problem. Table 2.1 briefly reviews the most common diagnostic methods and technologies for conformance problems. It is important to mention that despite the extreme importance of the water problem diagnosis, conformance issues are still qualitatively characterized in most situations, as will be illustrated in the second paper. In addition, the geological complexity and reservoir interferences continue to call for more robust diagnosing techniques and procedures.

In the following subsections, production plots and data analysis methods that used to evaluate conformance issues are discussed in more details:

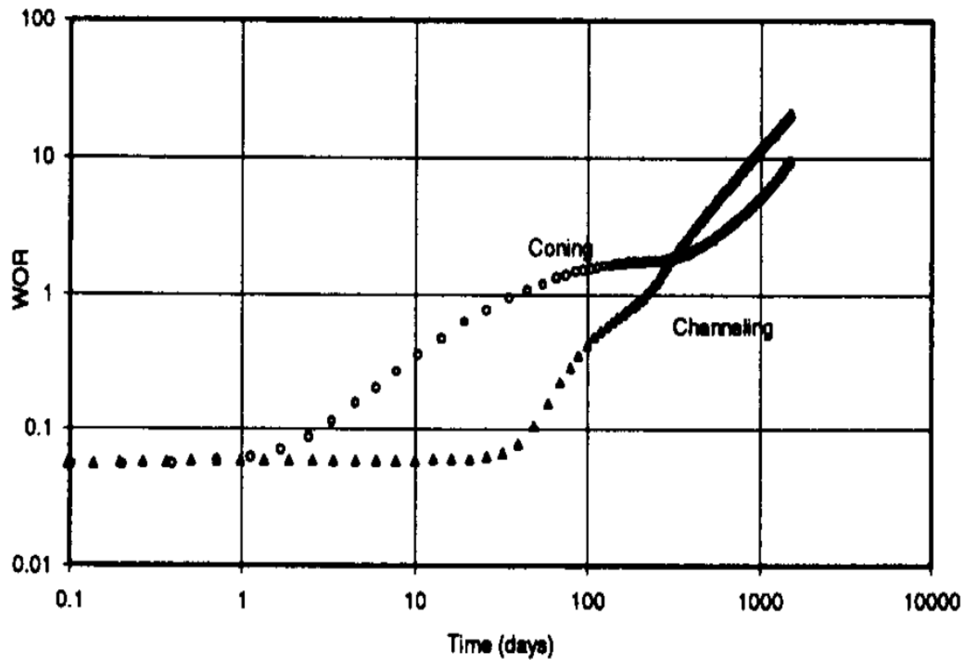
2.4.1. Chan Graphical Method. Chan (1995) proposed an easy and inexpensive diagnosis method that can differentiate whether the water production issue is a coning or a channeling problem. Chan illustrated based on the numerical simulation that different water production mechanisms have different characteristic trends for the WOR or its derivative with time on a log-log plot. This means that the method is based on the graphical comparison of the behavior of WOR after breakthrough for both types of conformance problems as shown in Figure 2.8. Several studies and diagnosis plots were later developed based on the same principles of Chan's method (Bondar and Balsingame, 2002; Yang and Ershaghi, 2005). Although this method continues to be used in the diagnosis of production wells (Stanley et al. 1996; Mahgoup and Khair, 2015), Seright (1997) demonstrated through the numerical simulation that multilayer channeling problems can easily be mistaken as bottom-water coning, and vice versa.

Table 2.1. Summary of Conformance Problem Diagnostic Techniques and Methods (After Sydansk and Romero-Zeron, 2011)

Diagnostic Method	Evaluation Techniques	Information obtained
Well Testing Methods	**Vertical Interference "Tests"** • Pulse tests • Formation testers • Multiple-well testing • Pressure-transient analyses	• Reservoir properties, horizontal and vertical permeability, crossflow between strata • Information on reservoir nonidealities that should be analyzed in conjunction with geological data; detection and characterization of fractures (volume, permeability, spacing between fractures, orientation) • Proper reservoir description with regard to static and dynamic properties
Interwell Tracer Tests	**Tracer Surveys** • Radioisotopes • Fluorescent dyes • Water-soluble alcohols • Water-soluble salts	• Indicate directional flow trends • Identify rapid interwell communication and reservoir continuity • Estimate volumetric sweep • Delineate flow barriers • Compare flow and sweep patterns • Characterization of fractured reservoirs: location and direction of fracture channels, fracture volume, fracture conductivity • Estimate the effectiveness of remedial treatments
Well Logging Tools	**Logging Tool Services** • Openhole logs: caliper, gamma, spontaneous potential (SP), and magnetic-resonance imaging (MRI) • Cement-evaluation logs: cement bond logging (CBL) and ultrasonic bond logs • Casing-evaluation logs: multiarm caliper tool, casing-inspection tool (CIT), flux-leakage/eddy –current (FL/EC) tool, circumferential acoustic scanning tool (CAST), and pulse-echo tool (PET) • Pulsed-neutron logs • Production logs: fluid-density tool, hydro tool, spinner tool, pressure tool, and temperature tool • Seismic methods	• Porosity, permeability, irreducible water saturation, fluid quantification (oil, water, and gas), water-cut prediction by integrating MRI log with resistivity logs. Reservoir heterogeneities. Identification of fractures or fracture-like features • Current condition of the cement annulus and diagnosis of potential fluid-flow paths • Integrity of the casing • Detection of channels outside the casing, leaking tubular, and water production • Crossflow between strata • Water influx, rate, and direction of flow

Table 2.1. Summary of Conformance Problem Diagnostic Techniques and Methods (After Sydansk and Romero-Zeron, 2011) (Cont'd)

Real-Time Downhole Video Services	• Downhole high resolution cameras that have the ability to work in extremely low-light environments.	• Identify wellbore problems, fluid turbulence, and flow direction. This information is useful to establish fluid migrations through the wellbore and into "thief" formations. Similarly, it allows planning reservoir and well treatments while in progress and confirms post-treatment well conditions
Reservoir Monitoring	• Analysis of production data (recovery factors, WORs) assisted by diagnostic plots to validate the quality of the production data (Anderson et al. 2006); examination of well production profile (Lane and Sanders 1995) • Analysis of well history (e.g., recompletions, well stimulation, major workovers) (Anderson et al. 2006) • Integration of reservoir description and reservoir simulation with multiple-reflection seismic surveys	• Monitoring of current movement of fluid saturations in a reservoir and prediction of future fluid-saturations movement, which provide vital information for delaying or preventing an early water or gas breakthrough.
Data Analysis Methods	• Chan graphical method • Seright et al. method • Interwell communication analysis • Pressure index technique (PI) • Well zoning procedures	• Distinguish coning from channeling problems • Determine fluid flow around the wellbore whether it is linear or radial • Estimation of drive-fluid channeling strength • Ranking of offending injectors based on interwell connectivity
Reservoir Simulation Studies	• 3D, three-phase, four-component, pseudo-compositional, and non-isothermal coupled reservoir/wellbore simulators	• Identification and understanding of the conformance problem • Prediction of the effect of conformance-improvement treatments on reservoir performance • Prediction of maximum water-free production rates • Estimation of breakthrough time, water-cut performance, and/or economic production rate



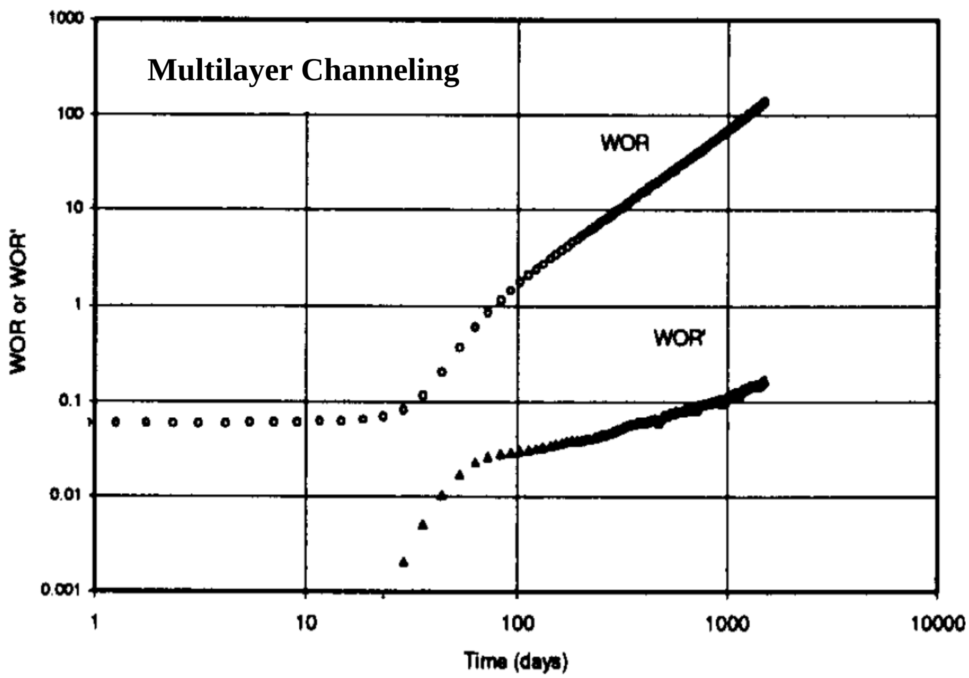


Figure 2.8. Chan Diagnostic Plots for Conformance Problems (Chan, 1995)

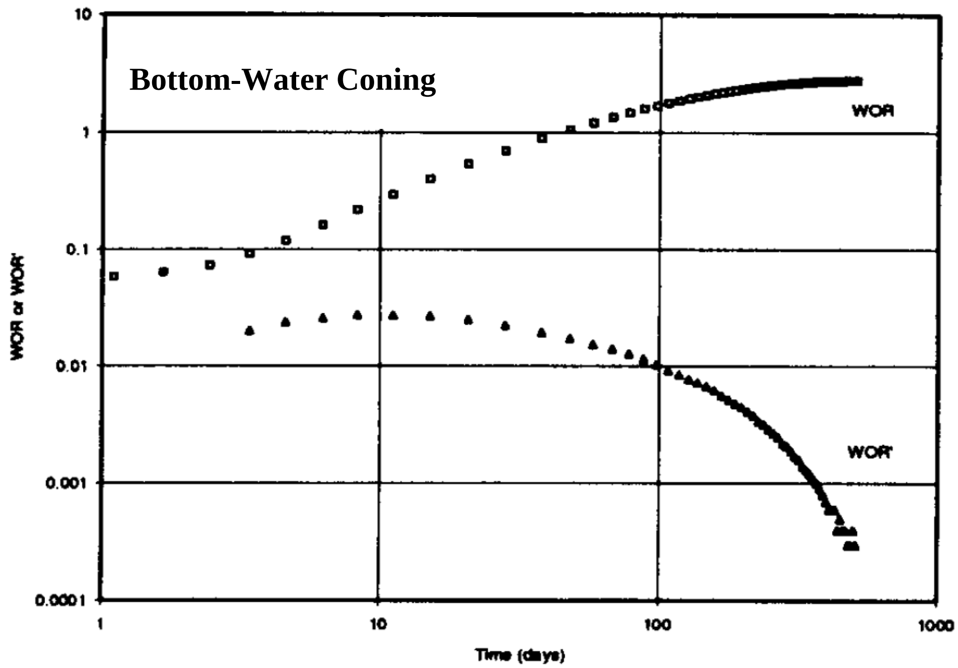


Figure 2.8. Chan Diagnostic Plots for Conformance Problems (Chan, 1995) (Cont'd)

Therefore, it has been recommended that WOR diagnostic plots should not be used alone to identify an excessive water production mechanism.

2.4.2. Seright Et Al. Method. As an indication for the drive-fluid channeling strength, Seright et al. (2001) have illustrated that a key aspect in the diagnosing of conformance problems is deciding whether fluid flow around the wellbore is radial or linear. Consequently, they proposed a simple and inexpensive diagnostic method that can determine the type of flow in a well. It is based on injectivity or productivity calculations using Darcy equation for radial flow as shown in the following equations:

$$\frac{q}{\Delta p} \gg \sum \frac{kh}{141.2\mu \ln(\frac{r_e}{r_w})} \quad (2)$$

$$\frac{q}{\Delta p} \leq \sum \frac{kh}{141.2\mu \ln(\frac{r_e}{r_w})} \quad (3)$$

They provided that if the actual injectivity for an injector is five or more times greater than the calculated injectivity using the Darcy equation for radial flow, the issue is linear flow problem. Alternatively, if the actual injectivity is less than or equal to Darcy equation estimation, the flow pattern is more likely to be radial. They also emphasized that in the practical application, uncertainty is the main reason that the above equations do not satisfy other field observations about the type of flow pattern.

2.4.3. Interwell Communication Analysis. In an effort to characterize the drive-fluid channeling strength in a systematic accurate manner, several analysis techniques have been used to identify flow channeling relationship using injection and production data. In a simplistic form, the analysis techniques try to correlate the changes in rates or pressures at the producer with water injection rates or pressures (Love et al. 1998; Baker et al. 2012). In these methodologies, the interwell connectivity is frequently represented by correlation factors or weighting coefficients that ranging between 0 and 1.0.

For example, if water production rate strongly follows water injection rate, then there is a strong channeling between the injector and producer as shown in Figure 2.9. Based on these measures of interwell connectivity, communication maps are generated to facilitate the ranking of injector-producer pairs as shown in Figure 2.10. Examples for these methods are Spearman Rank Correlation (Heffer et al. 1997), Multivariate Linear Regression (Albertoni and Lake, 2003), and Capacitance-Resistive Model (Yousef et al. 2005). Most recently, Yin et al. (2015) proposed a technique to estimate interwell connectivity by correlating 4D seismic surveys and production data or tracer test data. It is important to mention that these techniques and especially the Capacitance-Resistive

Model are receiving more attention in field application of conformance improvement technologies (Baker et al. 2014).

2.4.4. Pressure Index Technique. In this method, a 90 minutes falloff tests are performed for the suspected injection wells as shown in Figure 2.11 (Liu et al. 2006 and 2010). The pressure index (PI) is then calculated for each individual injector from the real-time recoded wellhead pressures using the following equation:

$$PI = \frac{\int_0^T p(t)}{T} \tag{4}$$

Lower PIs are usually estimated for the offending injection wells than other injectors in the field because higher pressure drawdown rates result from strong channeling strengths in these well patters. Injectors with PIs less than the average field-wide pressure index are considered as candidates for conformance improvement treatments. While this technique provides a relative or field-specific measure of interwell connectivity, it is mainly used to select well candidates for conformance improvement treatments.

2.4.5. Well Zoning Procedures. In history case studies, the well zoning refers to the nomination process of a well or well pattern from the many wells in a field for the application of a specific conformance improvement technology based on the functionality requirements of the desired technology. In this context, quantitative selection criteria are used to identify well candidates for conformance improvement technologies. These criteria enabled the identification and ranking of injectors and producers for the conformance remediation based on the degree of interwell connectivity. Well zoning parameters generally include the injection and production parameters such as water injectivity, water entry percent, PI technique, and communication analysis.

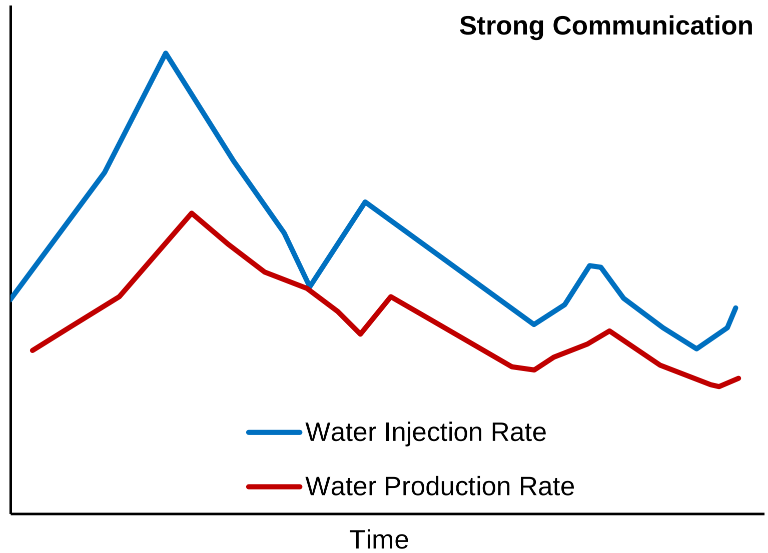


Figure 2.9. Trends of Water Flow Rates for a Strong Channeling Problem (Baker et al. 2012)

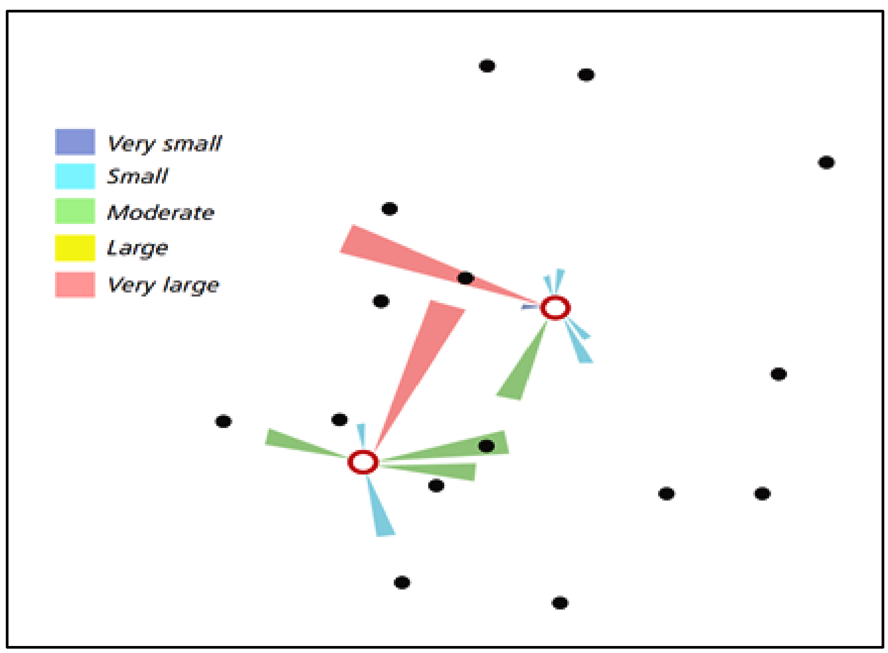


Figure 2.10. Interwell Communication Map (Baker Hughes SweepScan™, 2012)

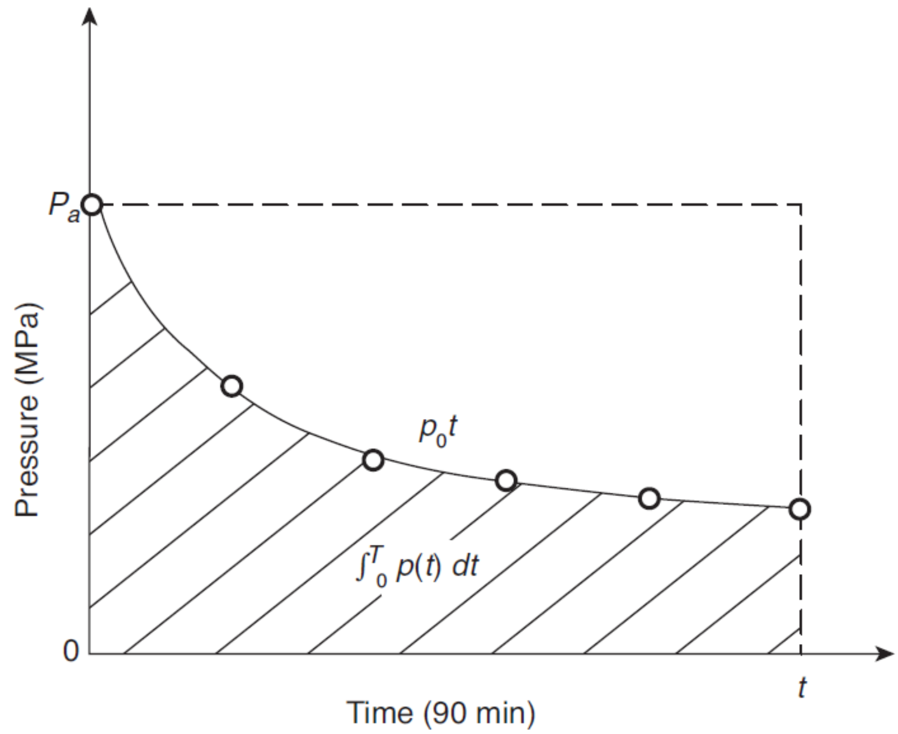


Figure 2.11. Injection Well Pressure Drawdown Curve for PI Technique (Liu et al. 2006)

For injectivity, entry percent, pressure index, and any other method that provide a relative or indirect measure for the channeling strength, a field-specific cut-off is specified to rate well patterns for conformance improvement treatments. For example, Love et al. (1998) proposed treatment selection matrix for both cement and bulk gels based on the water injectivity for EMSU field as shown in Table 2.2.

When absolute estimations of the interwell connectivity are provided by communication analysis or flow rate correlations (Figure 2.12), well patterns with channeling strength > 0.5 are considered for conformance improvement treatments (Chou et al. 1994; Baker et al. 2012). It is important to mention that some other factors are also considered in the well zoning like other channeling indicators, well integrity parameters, selective injection installations, and injection and production facilities. An example for the ranking of candidate injection wells in the Cerro Dragon filed for the thermally activated particle technology (BrightWater®) is shown in Table 2.3 (Mustoni et al. 2012).

Table 2.2. EMSU Field Treatment Selection Matrix (Love et al. 1998)

Water Injectivity		**Cement Squeeze**		**Bulk Gels**	
bpm	psi	With expanding agent	Foamed with N_2	Intermediate MW	High MW
1	600-900	X			
2	300-600	X	X		
3	100-300		X	X	
4	0-100			X	X
5	0			X	X

2.5. CONFORMANCE IMPROVEMENT TECHNOLOGIES

Numerous conformance improvement technologies are available to enhance sweeping efficiency of IOR/EOR floodings and to mitigate water production in conventional oil reservoirs. Generally, conformance solutions are classified into conformance agents and conformance operations or practices as shown in Table 2.4 (Seright et al. 2001). The first category includes all chemical and physical materials that are used as injectable plugging agents like polymer flooding, polymer gels, cement, and resins. The term chemical conformance technology is frequently used to describe most of these agents except cement and other solid materials. The second group includes operational mechanical and well techniques such as packers, bridges, infilling drilling and well abandonment.

Table 2.3. Ranking of Potential Well Candidate for BW Technology (Mustoni et al. 2012)

Factor	**Favorable Characteristics for BW**	**Candidate Waterflood Well Patterns**					
		CG-IIIW	**CD-III**	**ZII/VI**	**O1A**	**CGI**	**MC III**
Water oil ratio	High and rapid increase	3	3	3	3	3	2
Evidence of channeling	Variable production response to water injection. high permeability contrast	3	3	3	3	3	3
Injector-Producer Transit Times	> 30 days and <150 days	See Tracer Time Tests					
Downhole installations	Mechanically sound	2	3	2	2	2	1
Artificial lift system flexibility	Ability to adjust production rates	1	2	2	3	2	3
Stability of the pattern operation	Six months without operational changes	3	3	3	3	3	2
Geological model understanding	Well defined model and well correlation	3	3	3	3	3	2
Areal sweep potential	Good areal connectivity with few sealing faults	3	3	3	3	3	2
Scaling feasibility	Relative high oil production and large OIP target	3	3	3	3	3	3
Injection facilities	Flexibility to handle injection rate changes. Stable water quality and reliable monitoring and control systems	3	2	3	1	2	2
Production facilities	Capacity to test producers monthly	3	3	3	3	3	3
Operational history	Well documented production history	3	2	2	3	2	2
Number of “3’s”		**9**	**8**	**8**	**8**	**7**	**4**
Sum		**30**	**30**	**30**	**29**	**29**	**25**

Table 2.4. Conformance Improvement Materials and Techniques (Seright et al. 2001)

Conformance Agents	**Conformance Operations**
Foam, emulsion, particulates, precipitates, microorganisms	Packers, bridge plugs, patches
Polymer/mobility-control floods	Well abandonment
Polymer gels	Infill drilling
Resins	Pattern flow control
Cement, sand, calcium carbonate	Horizontal wells, advanced wellbores

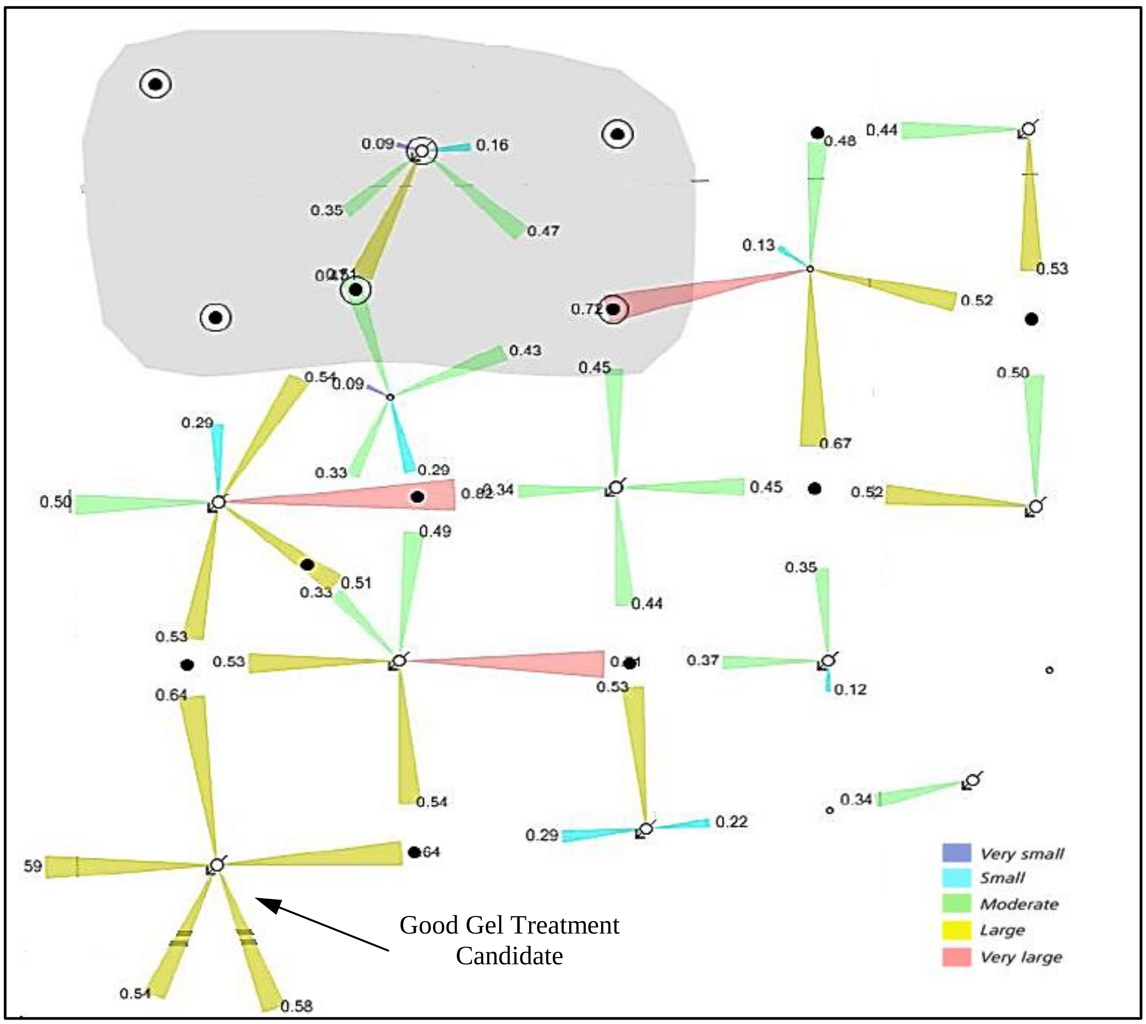


Figure 2.12. Communication Map Used for Well Zoning (Kashirsagar, 2014)

Conformance solutions are also categorized based on the objective of the application of a conformance improvement technology. Technologies that try to overcome some of the viscosity and density differences between the injected and reservoir fluids are termed as mobility control. In this sense, mobility related conformance issues are addressed by increasing the viscosity of the drive-fluid or by some operational practices like water-alternating-gas process (WAG).

Secondly, technologies that improve injection and/or production profiles are described as conformance control (Azari and Soliman, 1996). These technologies enhance fluid flow profiles by correcting the reservoir permeability heterogeneity using plugging agents, stimulation techniques, or by mechanical and well techniques. It is important to mention that conformance control includes any technology that addresses any type of heterogeneity in the oil and gas reservoirs. This means that mobility control is just one type of conformance control; however, in literatures conformance control has been connected to the remediation of permeability-related issues.

In short, conformance applications are either mobility control or conformance control. In addition, they are either increase viscosity of the drive-fluid, reduce permeability of high permeability zones, or increase permeability of low permeability zones. A summary of the most common conformance improvement technologies is presented in Table 2.5.

Matching a conformance issue to a conformance improvement technology represents the most important step in the water management project (Sydansk and Southwell, 2001, Seright et al. 2001, Kabir, 2001). This is mainly because that each conformance improvement technology correctly functions for only a certain types of conformance issues (Seright et al. 2001). Therefore, it is essential that a conformance problem is correctly characterized to select the best suited conformance improvement technology.

The incremental oil production and decremental water production represent the major outcomes of conformance improvement applications with respect to the technical prospect. The economic feasibility of IOR/EOR floodings would be improved by the associated additional revenues from oil production and operating expense savings result from water production reduction. The benefits of the application of conformance improvement technologies are of extreme importance for the mature oilfields as they extend their productive lives and reduce their environmental liabilities. In the next section, polymer gels will be reviewed in details as they are the focus of this study.

2.6. GEL AND POLYMER GEL CONFORMANCE TECHNOLOGIES

Gels are elastic semi-solid materials that are basically used to reduce permeabilities of the high flow capacity zones in the conventional oil reservoirs. Oilfield gels have several chemistries, forms, mechanisms, and even additional objectives other than permeability reduction as it will be illustrated later. Therefore, among the chemical conformance improvement technologies, gel technologies have been proven to be an effective solution for a wide spectrum of conformance issues. As seen in Section 2.3 and will be further elaborated in Section 2.10, oilfield gels are applied to treat wellbore, near-wellbore, and far-wellbore problems when they match the requirements of these conformance issues.

Table 2.5. Representative Types of conformance Improvement Technologies (Sydansk and Romero-Zeron, 2011)

- **Cement (Portland)**
  - Squeeze cementing
  - Foamed cement
  - Microfine cement
  - Grey-water cement solutions
  - Cement containing specialty chemicals

- **Flooding with viscous fluids**
  - Polymer flooding

- **Permeability-reducing treatments**
  - Gels
    - Inorganic-based bulk gels
      - Silicate gels
    - Organic-based polymer bulk gels
      - Polymers
        - Synthetic
        - Biopolymers
      - Crosslinking agents
        - Inorganic
        - Organic
    - Organic-monomer-based in-situ-polymerized gels
    - Preformed polymer-gel particles
      - Microgel particles
      - Delayed-swelling microgel particles
      - Colloidal dispersion gels
      - Preformed swelling gel particles
  - Resins
  - Specialty polymers alone for relative-permeability-modification (RPM)

- **Foams and foam flooding**
  - Conventional foams
  - Polymer-enhanced foams
  - Foamed gels

- **Particulates**

Table 2.5. Representative Types of conformance Improvement Technologies (Sydansk and Romero-Zeron, 2011) (Cont'd)

• **Mechanical wellbore methods** ➢ Packers and bridge plugs ➢ Straddle packers ➢ Sliding sleeves ➢ Tubing patches ➢ Sand-back plugs
• **Wellbore drilling and completion methods** ➢ Selective completion and selective perforating ➢ Use of horizontal and multilateral wellbores ➢ Use of intelligent wells and well completions ➢ Use of wells that can be selectively "snaked" through the reservoir
• **Well locating** ➢ Strategic and optimum areal placement of vertical wells ➢ Strategic well pattern selection and placement ➢ Strategic and optimum placement vertically and directionally of horizontal wells
• **Infill drilling**
• **Well abandonment and selective shut-ins**
• **Pattern balancing, well realignment, and shut-ins**
• **Comprehensive reservoir description**
• **Increasing the permeability of low-permeability flow paths** ➢ Acidizing ➢ Selective hydraulic fracturing ➢ Deep perforating

Oilfield gels are generally classified based on their chemical compositions into inorganic bulk gels and organic polymer gels as shown in Table 2.6. Inorganic gel systems are formed by the polymerization and condensation of sodium or aluminum silicates. Gelation process of silicates starts when the pH of the solution is reduced or increased using some acids like HCL and H_2SO_4 (Krumrine and Boyce, 1985; Iler, 1979; Lakatos et al. 1999; Stavland et al. 2011).

Polymer gels are formed by the chemical crosslinking of an aqueous water-soluble polymer solution using a crosslinking agent. Polymer gels also involve several forms and chemistries as many polymers and crosslinking agents have been used in their formulations as shown in Table 2.6. They are classified according to their ingredients, where the gelation process occurs, and the resulting gel structure. Synthetic polyacrylamide-based gels are the most widely applied chemical conformance-improvement system (Sydansk and Romero-Zeron, 201; Lantz and Muniz, 2014). Polyacrylamides can be either organically (OCAP) or metallically (MCAP) crosslinked depending on type of the crosslinking agent used to form the gel system.

Traditionally, polymer gels have been injected as a watery gelant solution consisted of polymer, crosslinking agent, and additives that forms a semi-solid 3D network structure in the reservoir as shown in Figure 2.13. These systems are called in-situ gel technologies and they are the focus of this study. In this study, three partially hydrolyzed polyacrylamide, in-situ gelling conformance systems are considered for screening purposes. Alternatively, polymer gels can be formed at the surface facilities and then injected into a reservoir as preformed particles gels (PPG) as shown in Figure 2.14 (Bai et al. 2007; Bai et al. 2008). Preformed particle gels overcome some of the in-situ gelation process drawbacks that greatly affect gelation time, gel strength, and gel placement. When polymers are crosslinked in the reservoir, reaction kinetics is affected by the shear rates that polymers experienced when flow through the wellbore into the reservoir. Changes in gelant ingredients amount are very likely due to rock adsorption,

Table 2.6. Oilfield Conformance Improvement Gel Technologies (Sydansk and Romero-Zeron, 2011)

Inorganic Bulk Gels

- Silicate gels
- Aluminum-based gels

Organic Polymer Gels

- Bulk gels
  - Synthetic or biopolymers
    - Acrylamide polymers (most widely used polymer)
    - Xanthan biopolymer
  - Organic crosslinkers
    - Aldehydes
      - Phenol-formaldehyde and derivatives
    - Polyethyleneimine
  - Inorganic crosslinkers
    - Al(III) based
    - Zr(IV) based
    - Cr based
      - Cr(VI) redox
      - Cr(III) with inorganic anions
      - Cr(III) with organic carboxylate complex ions
- Monomer gels (organic-monomer-based in-situ polymerization)
  - Acrylamide monomer
  - Acrylate monomer
  - Phenolics
- Lignosulfonate gels
- Preformed particle gels
  - Swelling organic-polymer "macroparticle" gels
- Mixed silicate and acrylamide-polymer gels
- Microgels
  - Microgels with narrow particle-size distribution
  - CDGs
    - Aluminum-citrate crosslinked
    - Chromic-triacetate crosslinked
  - Delayed "popping"/swelling microgels (BrightWater^{TM})

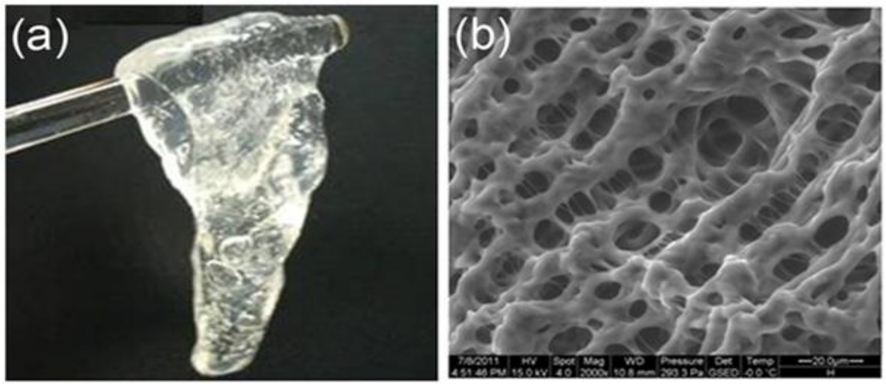


Figure 2.13. Form and Structure of Bulk Gels (Zhao et al. 2013)

Figure 2.14. Dry and Swollen Preformed Gel Particles (Imqam et al. 2016)

reactions with minerals, and dilution by formation water. Extensive comparisons of preformed particle gels and in-situ gels can be found in the work of Liu et al. (2006).

In a gel treatment, polymer gels are injected to effectively penetrate the offending high conductive zones deep into the reservoir to block them off and provide a sustainable diversion of the subsequent injected water toward unswept, low permeability zones as shown in Figure 2.15. Such remediation would mitigate water production and enable recovery of bypassed oil reserves in cost-effective way and thus, extend the productive life of mature oilfields. Polymer gels can be applied to treat either production or injection wells; however, it is always preferable to treat injection wells as it less risky and the desire to address the water source in the IOR/EOR flood processes.

2.6.1. Bulk Gels. Bulk gels (BGs) are probably the most widely applied polymer gel system for conformance improvement purposes (Sydansk and Southwell, 2000; Lantz and Muniz, 2014). These gels can be formed using high molecular weight (8-13 million daltons) partially hydrolyzed polyacrylamides with a crosslinker. The high polymer concentrations result in a continuous semi-solid 3D network structure for the gel. Bulk gels provide a wide range of strengths and a wide range of controllable gelation times; thus, they can be applied to injection or production wells for profile control or water shut-off purposes.

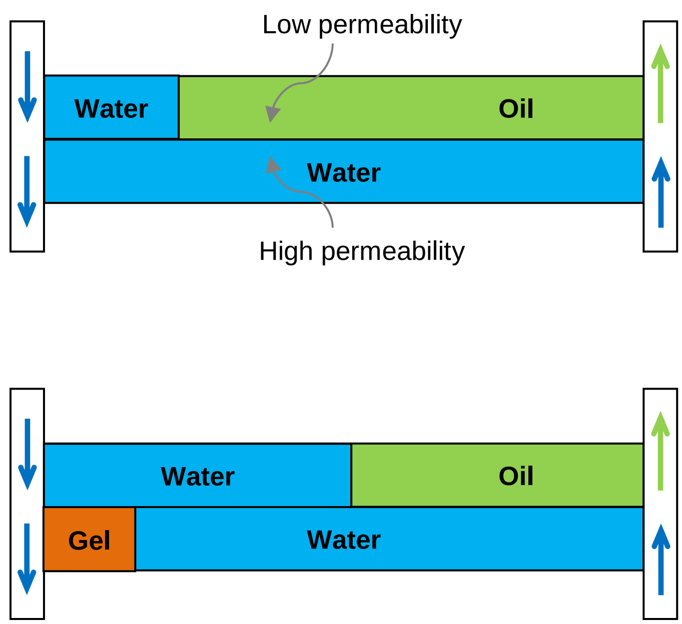


Figure 2.15. Illustration of Gel Treatment Function and Objective

This gel system has two versions depending on the type of crosslinking agent. For MARCIT[SM] gels developed by Marathon Oil Company, polyacrylamide polymers are crosslinked using a trivalent metal ion which is usually Chromium (III) (Sydansk and Smith, 1988). Chromium (III)-Carboxylate/Acrylamide-Polymer (CC/AP) gels are characterized by having robust gel chemistry in water with a wide range of water salinities, being highly insensitive to reservoir interferences. They are also resistance to CO_2 and H_2S, easy to implement in field, and cost competiveness (Southwell, 1999). CC/AP gels are applicable over a broad reservoir temperature range; however, extensive laboratory and field cases confirmed that they should be used in a formation temperature of less than 220°F (Sydansk and Southwell 2000). For high temperature applications, medium molecular weight polyacrylamide polymers are crosslinked with an organic agent and a stabilizer to delay the gelation process. In this study, these gels are depicted as organically-crosslinked-polyacrylamides bulk gels (OCAP-BGs). An example of this specialized chemistry is the UNOGEL technology developed by Union Oil Company of California (UNOCAL) which can be applied at temperature ranges of 200 to 300 °F (Norman et al. 2006).

Bulk gels are applied to treat strong drive-fluid channeling that typically occurs in naturally fractured reservoirs and extremely high permeability matrix-rock reservoirs (Smith and Larson 1997). Bulk gels are designed to reduce water production by totally or partially blocking the high conductive zones by reducing their permeabilities. Typical injected volumes of these agents range from a few hundred to tens of thousands of barrels; therefore, offending zones that are small in volumes relative to the size of the reservoir are good candidates. From their state-of-the-art, bulk gels are only considered as plugging agents, or a conformance-control strategy that works solely by correcting the formation permeability heterogeneity.

2.6.2. Colloidal Dispersion Gels. Colloidal Dispersion Gels (CDGs) are in-situ microgel aggregates that are formed by crosslinking of low concentrations (150 to 1200 ppm) of high-molecular-weight (> 22 million daltons) hydrolyzed-polyacrylamide polymer with aluminum citrate or chromic citrate to produce a weak gel. Such low polymer concentrations are not enough to form a continuous network, and thus, they produce a solution of separate gel bundles that are almost spherical particles with sizes in the range of nanometers of 50 to 150 nm (Castro et al. 2013). These gels can flow under differential pressures that are greater than their transition pressures, as was experimentally demonstrated by Mack and Smith (1994).

The application of CDGs is limited to injection wells and involves injection of large volumes that are comparable to those of polymer flooding and are expressed in terms of pore volumes as well. Sweep efficiency improvement is achieved by providing in-depth fluid diversion due to deep gel penetration and weak strength that result in complete or partial blocking of high-conductive zones. Mack and Smith (1997) mentioned that based on field results, CDGs work by flooding preferred water flow paths between injectors and producers once-through, they restrict the flow to preferential water paths and force it to tighter rocks. This conformance technology has been widely applied to heterogeneous matrix-rock sandstone reservoirs produced by waterflooding with adverse mobility ratios. It is important to note that CDGs are the precursor of some other conformance agents or processes (Figure 2.16) that were previously attempted to achieve the in-depth placement for the treating agents.

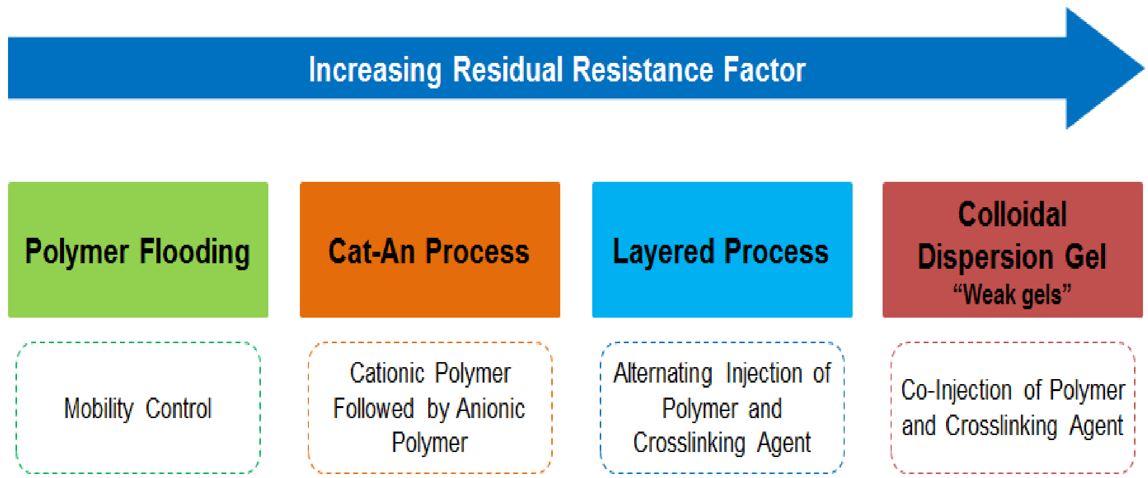


Figure 2.16. Development Stages of Colloidal Dispersion Gels (Lantz and North, 2014)

Many studies have recently displayed CDGs as a feasible technology fundamentally for mobility control with additional benefits of reducing the permeability of high conductive zones (Castro et al. 2013). They have also stated that this technology is an alternative or a modified version of the polymer flooding like some other studies (Manrique and Lantz, 2011). Others have given equal importance to both functions of these agents as in-depth conformance improvement and mobility control strategy (Manrique et al. 2014). However, both groups have referred to injection of CDGs as "floods" rather than "treatments" due to the large volumes injected in the field applications. Furthermore, they have stated and validated the possibility of displacement of viscous oil s by CDGs by comparing the oil responses of the first and second treatments of a retreated injection well. It is noteworthy that in this study, only CDG historic cases that involved the co-injection of the polymer and crosslinker have been considered where the early sequential gel applications were eliminated.

CDGs have uniquely gained many longstanding controversial issues based on several laboratory evidences (Seright, 1994 and 2007; Ranganathan et al. 1998; Smith et al. 2000; Lu et al. 2000; Chang et al. 2006; Wang et al. 2008; Al-Assi et al. 2009; Spildo et al. 2009 and 2010, Castro et al. 2013; Diaz et al. 2015) and some critical reviews of their field performances (Seright, 1994 and 2015; Chang et al. 2006; Manrique and Lantz, 2011; Manrique et al. 2014). Examples for debatable issues or questions about CDGs are: do they really form gel aggregates as crosslinker is highly retained in reservoir conditions? Do they propagate deeply into normal permeability matrix-rock sandstones? Do they provide a greater resistance factor than uncrosslinked polymers? Can they be injected in large volumes without reducing injectivity or causing face plugging in injection wells? Are they technically or economically superior to the traditional polymer floodings? Summaries and discussions about these issues can be found in work of El-karsani et al. (2012) and Abdulbaki et al. (2014).

Spildo et al. (2010) and Diaz et al. (2015) have provided that comparisons of results from different experimental investigations is made difficult by the variations in one or more of the factors controlling the gelation process from one study to the other. In addition, many researchers (not only CDG vendor's researchers) mentioned that despite the uncertainty around the mechanisms of different microgels systems, these technologies are gaining popularity as a conformance control treatments (Abdulbaki et al. 2014). It is important to mention that many of the technology vendor's studies and other researchers have clearly explained that CDG technology is not well understood and there are big discrepancies between laboratory studies and field performances (Manrique and Lantz, 2011; Spildo et al. 2009). Manrique et al. (2014) have provided that a comprehensive review of laboratory protocols needs to be revisited to better explain field observations.

2.6.3. Weak Gels. Weak gels (WGs) are a subdivision of the bulk gel systems that have been terminologically separated to distinguish their objectives of application from those of the original technology, i.e., BGs. Essentially, these agents are low to intermediate polymer concentrations, weak strength bulk gels that can have the same or different mechanisms for improving sweep efficiency depending on how and where they are applied. They can be used for both profile modification remedies and in-depth fluid diversion treatment based on the drive-fluid channeling degree and the injected gel volumes. In literature, several criteria have been used to characterize this gel system as illustrated by the following points:

1- In the bottle testing gel strength code system (A to J) proposed by Sydansk (1990), weak gels have Code B which refers to a highly flowing gel.
2- Han et al. (2014) have categorized a gel system as a weak gel if it has a storage modulus ($G^{'}$) less than 1 dyne/cm^2.
3- Wang et al. (2002) experimentally have showed that in order to form a weak gel, the storage modulus should be in the range of $0.1 < G^{'} < 10$ dyne/cm^2. The authors have also noted that the minimum polymer concentration required to form a weak gel is 2000 ppm, and the differences between storage modulus and the viscous modulus are relatively small.
4- Liu et al. (2010) reported that weak gels have polymer concentrations between 800-2000 ppm without further illustration about the resulted gel structure.

5- Some researchers have implied that any bulk gel system (regardless of its concentration) is a weak gel if it forms a flowing gel in the reservoir conditions under certain ranges of pressure gradients. Sheng (2011) mentioned that weak gels have a high resistance to flow but are still able to flow so can be injected deep into the reservoir. Han et al. (2014) provided similar ideas and referred to WGs and CDGs as flowing gel processes. Furthermore, Song et al. (2002) and Lu et al. (2010) pointed out that WGs are oil-displacement agents in addition to their function as blocking agents.

Weak gels have been extensively applied in Chinese oilfields in heavy oil, unconsolidated sandstone reservoirs as in-depth fluid diversion technology. It is important to mention that both metallic and organic crosslinking agents were used to form weak gels in these applications. However, organic crosslinkers were not used for the purposes of high temperature applications as reservoirs temperatures in most of these cases are from 109 to 163°F.

2.7. TYPES OF CHEMICAL CONFORMANCE CONTROL

Often, it is referred to chemical conformance control practices that address permeability-related conformance issues as conformance improvement treatments. In general, conformance improvement treatments are classified into a number of categories according to some technical aspects such as the type of treated wells. In addition, a number of terms are used to describe these categories that are important to know for the sound reporting and communication within oil and gas industry.

First, conformance improvement treatments are categorized based on the remedy objective whether it is to improve the volumetric sweep efficiency of IOR/EOR floodings or to mitigate water production (Sydansk and Southwell, 2000). In other words, the classification is based on whether the required mechanism for the treating agent is displacement and diversion or plugging and diversion.

Secondly, some studies have classified the remediation of conformance problems based on the implementation time whether it is before or after the channeling of the drive-fluid. Conformance improvement treatments that are applied at early times are described as proactive or preventive treatments while remedies that are implemented at late stages in the flooding life are termed as reactive treatments. It has been indicated that preventive treatments are less costly and more effective than reactive treatments (Soliman et al. 2000; Pipes and Schoeling, 2014).

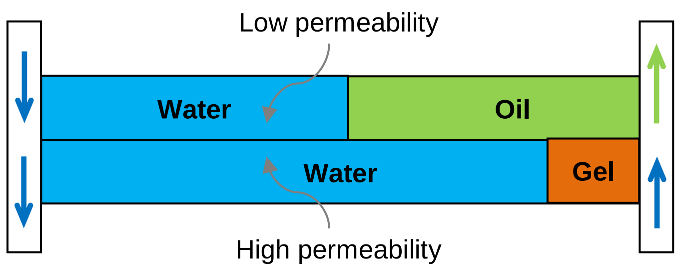
Finally, conformance improvement treatments are classified into the three categories based on the type of the treated well whether it is injector or producer as shown in Table 2.7. In addition, injection well treatments are subcategorized according on the injected gelant volume or gel penetration depth. The next subsections present the major types of chemical conformance improvement treatments.

2.7.1. Water Shutoff Treatment. This type of conformance improvement treatments is applied to the production wells to correct the reservoir permeability heterogeneity in the near wellbore region as shown in Figure 2.17 (a). Two treating agents can be used to treat production wells depending on whether there is or not an impermeable barrier separating the oil and water producing zones. For separated layer reservoirs, strong plugging agents like polymer gels can be used and the treatment is characterized as non-selective water shutoff treatment. In these treatments, conformance agents block the high permeability zones and divert the subsequent injected fluids into the low permeability zones. For single layer reservoirs, relative-permeability-modification polymers and gels are applied and such treatments are termed as selective water shutoff remedies. The placement technique represents a success key for non-selective water shutoff treatments while RPM treatments can be bullheaded.

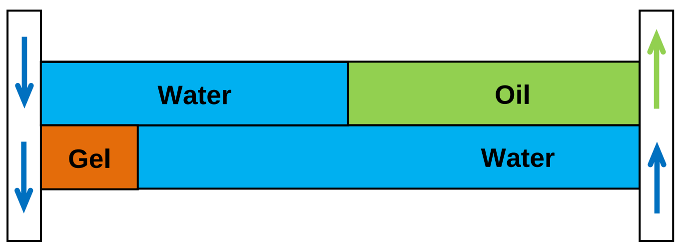
Table 2.7. Types of Chemical Conformance Improvement Treatments (Han et al. 2014)

Treatment Type	Well Type	Treatment Diameter	Targeted Problems	Advantages	Disadvantages
Water Shutoff	Producer	3-30 ft	Thief zones Water Coning	Immediate Response	Low Success Rate and High Risky
Profile Modification	Injector	30-100 ft	High Permeability Zones	High Success Rate	Short-Lived Response
In-Depth Fluid Diversion	Injector	0.1-0.5 PV	Crossflow Problems	Far-wellbore Effects	Large Volumes

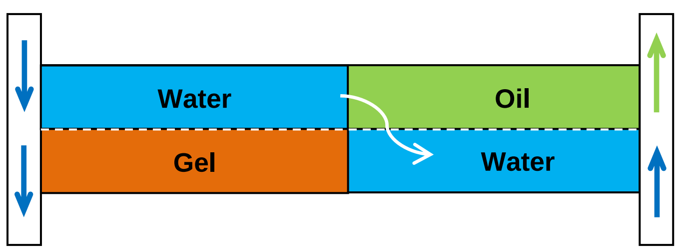
2.7.2. Profile Control Treatment. A near wellbore treatment that is applied to injection wells to solve water channeling problems that are caused by the substantial permeability variation as shown in Figure 2.17 (b). The total or partial plugging of high permeability zones would increase the fluid admission or entry into the low permeability zones and thus, oil production is increased. Often, small volumes of plugging agents are enough to address the problem if there is no vertical pressure communication and crossflow between reservoir layers. Usually strong plugging agents are used like bulk gels, cement, or a combination of them. Again, the placement method plays an important role in the performance and success of such treatments.



(a) Water Shut-off



(b) Profile Control



(c) In-Depth Fluid Diversion

Figure 2.17. Types of Gel Conformance Improvement Treatments

2.7.3. In-Depth Fluid Diversion Treatment. When there is vertical fluid crossflow between reservoir layers and near-wellbore treatments are applied, the injected fluid returns to channel into the producers after bypassing the placed treatments. Therefore, to obtain a long term fluid diversion for the subsequent injected drive-fluid, large volumes of treating agents are placed in deeply the reservoir through the injection wells as shown in Figure 2.17 (c). For in-depth fluid diversion (IFD) treatments, large volumes of some agents like weak gels, preformed particle gels, and colloidal dispersion gels are placed in the middle between the injection and production wells. IFD treatments are often sized to fill more than 10% of the treated well pattern pore volume or about one third of the distance between the injector and producer (Wang et al. 2001; Han et al. 2014).

2.8. PLACEMENT TECHNIQUES OF CONFORMANCE CHEMICALS

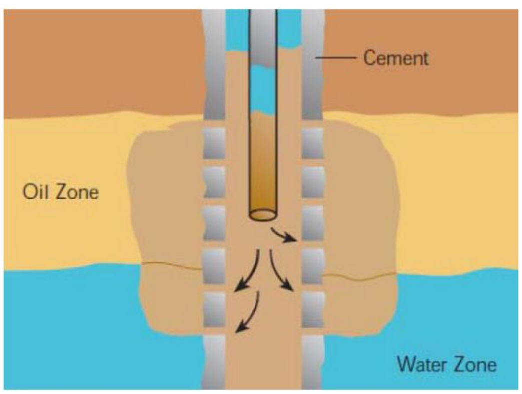
Placement technique refers to the way by which injectable conformance materials are introduced into a reservoir. Depending on the used technique, treating agent can be injected either into all reservoir layers or only into a specific zone. The objective of using some improved techniques such as mechanical isolation instead of the traditional bullhead method is to minimize the penetration of the treating agent into productive zones. Therefore, selecting the right placement technique represents a key component for a successful conformance improvement treatment when a vertical conformance problem is being remedied (Miller and Chen, 1997; Bybee, 2004; Wassmuth et al. 2004; Ansah et al. 2006; Jaripatke and Dalrymple, 2010). Seright and his colleagues have extensively investigated this issue for different flow systems to identify the optimum placement method (Seright, 1988; Seright, 1991; Sorbie and Seright, 1992; Liang and Seright, 1993; Seright, 1995; Seright et al. 2001). These studies and others illustrate that for matrix-rock radial-flow problem type, mechanical zone isolation must be used to secure low permeability zones if vertical crossflow is not expected.

Jaripatke and Dalrymple (2010) have provided that placement procedures should be selected on a well-to-well basis and similar to the method used for the injection of dive-fluids. They reviewed and discussed features and drawbacks of main placement techniques used in field as shown in the following subsections.

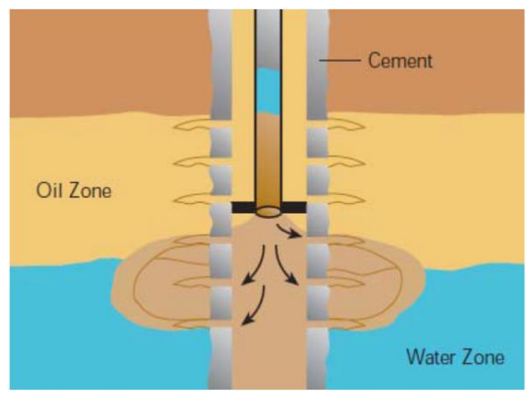
2.8.1. Bullhead Placement. The bullheading of treating agents is the most used economic placement method in which agents are introduced into all open reservoir zones or perforations as shown in Figure 2.18 (a). This means that conformance materials are simply injected through existing tubulars and no workover operations are required. This placement technique is considered risky and not preferable as it might result in plugging of both water and oil zones.

2.8.2. Mechanical Isolation Placement. Mechanical packers, bridge plugs, other downhole selective injection installations (mandrels) are used to guide plugging agents only to high capacity layers while isolating oil bearing zones (Figure 2.18 (b)). Existing of an impermeable barrier between oil and water zones represents an essential need for this placement technique to provide the required isolation action. Costs of associated workover operations that can consist about 60% of the whole treatment cost represent the main disadvantage of this mechanical isolation placement.

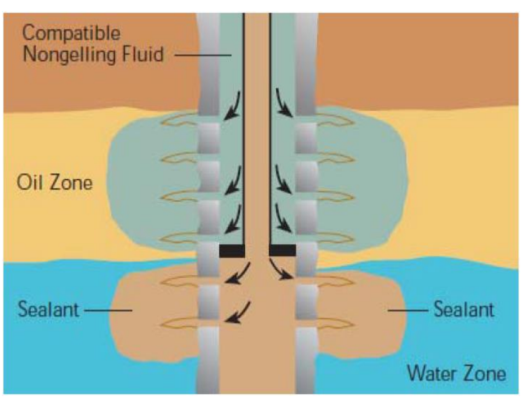
2.8.3. Dual-Injection Placement. In this method, low permeability oil-bearing zones are also isolated using a packer. Treating agents are pimped down the tubing into high capacity zones while a compatible fluid (diesel for example) is pumped down the annulus into low capacity zones. A key success factor for this placement is the controlling of surface injection pressures in way that grantees a balanced fluids flow as shown in Figure 2.18 (c). The practical difficulty of achieving balanced flow for injected fluids and large associated expenses are most limiting factors for this technique.



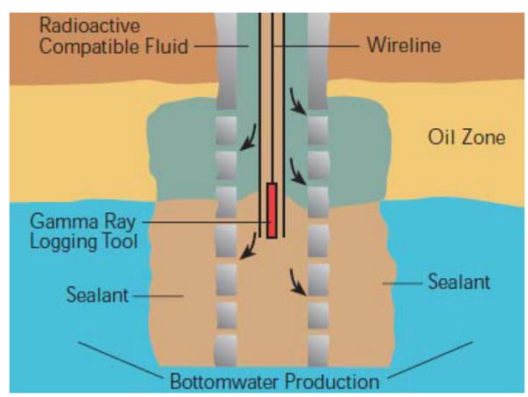
(a) Bullhead Placement



(b) Mechanical Isolation Placement



(c) Dual-Injection Placement



(d) Isoflow Injection Placement

Figure 2.18. Conformance Agent Placement Techniques (Jaripatke and Dalrymple, 2010)

2.8.4. Isoflow Placement. As with dual-injection placement, Treating agents are injected down the tubing and kept away from low capacity zones by injecting a compatible fluid down the annulus, but without packer. In addition, a radioactive tracer is added to the compatible fluid and a detection tool is placed in the tubing to assist in balancing both fluid flow rates as shown in Figure 2.18 (d).

2.8.5. Transient Placement. In this method, the selective placement is achieved by making a sharp reduction in injection pressure when the plugging agents reached the target zone. Breston (1957) stated that such step would create a transient period during which fluids in the reservoir could flow back into the wellbore as shown in Figure 2.19. Obviously, this placement can only be used in the wells that experiencing significant intra-wellbore crossflow during shut-in times. Seright (1998) discussed this method and provided that the supporting evidence for the placement of enough plugging agents can be placed was not provided.

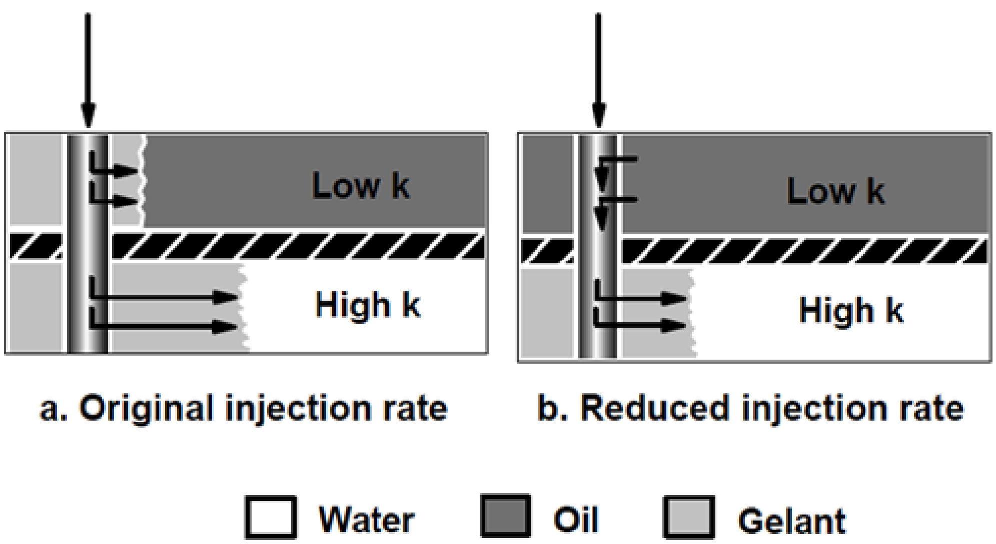


Figure 2.19. Transient Placement Technique (Seright, 1998)

2.9. EOR SCREENING CRITERIA

As a first step, reservoir engineers usually refer to screening criteria to identify a potential recovery process for a given reservoir out of the many available EOR methods. Screening criteria determine the applicability of an EOR process by checking the compatibility of injected fluids with reservoir rocks and fluids properties. These criteria are established from real field applications of the EOR methods and summarized or formulated in terms of reservoir and fluid properties. In other words, EOR criteria represent the intervals of validity of each influential property based on successful field tests, engineering considerations, and experts' opinions (Alvarado and Manrique, 2010). Reservoir permeability, depth, temperature, oil viscosity, oil saturation, and other characteristics are usually considered in the analysis. Screening criteria are generally classified into two classes depending on the form and driver of the method itself: conventional and advanced. It is important to note that the term "applicability guidelines" is interchangeably used for screening criteria in this study.

2.9.1. Conventional Screening Criteria. The traditional EOR guidelines are represented by a table contains the ranges of the influential reservoir/fluids characteristics as shown in Table 2.8. The descriptive statistical parameters like minimum, maximum, mean, median, and standard deviation usually form the structure or shape of such EOR screening rules. Scatter plots and histograms are also used sometimes to present data ranges and project distributions. The driver of this type of EOR screening criteria is the simple comparison of a given reservoir conditions with the prescribed application ranges. Thus, they provide a "go / no-go" decision type criterion and are incapable of ranking the candidate EOR solutions.

Table 2.8. Polymer Flooding Screening Criteria (Saleh et al. 2014)

Property/Statistic	Mean	Median	St. Dev.	Minimum	Maximum
Oil Gravity, °API	31.2	32	8.26	12	48
Oil Viscosity, cp	12.21	4	19.74	0.3	130 (special case 1000-5000)
Porosity, %	18.15	17.4	5.4	4.1	36.1
Oil Saturation (Start), %	55.85	53	15.5	21	94
Oil Saturation (End), %	46.57	47	13.37	20	80.9
Permeability, md	384.88	100	874.55	0.6	5500
Depth, ft	4004.21	3650	1925.8	550	9400
Temperature, °F	118.1	110	30.06	65	210

Taber et al. (1997) introduced the first conventional screening criteria for all EOR processes in both tubular and graphical (histograms and cross-plots) forms. Henceforth, more than 100 guidelines have been developed (based on SPE papers until 2016) and updating efforts are continuing. In addition, data from laboratory evaluations and numerical simulation studies have been utilized to develop new guidelines and to be compared with field-type criteria (Bang, 2013, Saleh et al. 2016).

2.9.2. Advanced Screening Criteria. In the second category of EOR screening criteria, artificial intelligence and machine learning techniques are utilized to develop screening algorithms or models. The EOR screening is considered as a classification problem where historical EOR application data are used to train classifiers to create classification rules. Classifiers identify the candidate EOR processes based on the similarity of characteristics of a new incoming case and EOR application conditions. Their outcomes are usually decision trees, clustering maps, or probabilities (score factor) of the considered technologies; therefore, they can rank the proposed solutions and indicate an analog for the field under evaluation. Alvarado et al. (2002) pioneered the application of machine learning in this field and since then, many advanced models have been developed to screen and rank EOR processes (40 studies based on the SPE papers). Various techniques have been used to address EOR screening like clustering analysis (Alvarado et al. 2002), expert systems (Guerillot, 1988; Gharbi, 2000), artificial neural networks (Parada and Ertekin, 2012; Kamari et al. 2014), and Bayesian network (Zerafat et al. 2011).

2.10. PREVIOUS POLYMER GEL APPLICABILITY GUIDELINES

The identification of the most appropriate gel technology for a given reservoir is a key factor for a successful conformance improvement treatment. The associated diagnosing costs make gel technology selection process crucial and extremely important in the capital-sensitive water control projects. However, this process is quite complicated and challenging for reservoir engineers due to several geological and technical reasons or complexities. These reasons are related to both conformance issues and improvement technologies and can be summarized by the following points:

1- As mentioned earlier, conformance problems encompass a broad range of issues that may exist anywhere from the wellbore to deeply in the reservoir. In particular, reservoir conformance issues have many types as their main root, the permeability spatial variation occurs in various forms and directions (Section 2.5).

2- Polymer gels have a wide range of forms and chemistries that function by different mechanisms to improve volumetric sweep efficiency of IOR/EOR recovery processes. In addition, gel technologies are applied to treat a number of conformance issues in either injection or production wells.

3- As a matter of fact, treating a specific conformance issue requires a distinct gel technology that matches problem characteristics (Seright et al. 2001).

4- Characteristics of conformance problems are difficult to be assessed or measured in the field with precision. Consequently, they have been qualitatively or subjectively characterized using several diagnosing techniques along with the traditional geological and reservoir characterization.

5- Two facts reveal that there is a need to efficient conformance agent selection advisor which is not exists yet. First, for reservoirs that exhibit multiple forms of heterogeneity, a combination of conformance agents is needed. Secondly, gel systems are simultaneously screened for a conformance problem (multiple screening). These facts call for a selection system that is not only able to identify, but also to rank gel technologies for a certain reservoir.

The complexity of conformance solution selection process has resulted in the development of three different types of studies to deal with the evaluation of polymer gels applicability including:

1. Numerical screening criteria studies
2. Qualitative candidate selection criteria studies
3. Conformance problem classification studies

In the next subsections, the above studies will be reviewed and discussed in some details to identify features and lacks.

2.10.1. Numerical Screening Criteria. Screening criteria in terms of reservoir and fluid characteristics have been widely used to identify the potential EOR technologies for a specific reservoir. Despite the large number of implemented gel field projects, only few conventional screening criteria have been sporadically accomplished for polymer gels that suffer from many lacks and drawbacks. This observation can easily be verified by comparing the numbers of screening criteria of polymer gels and other EOR methods as shown in Figure 2.20. The rear utilization of these criteria in history case studies would also confirm the above observation.

In addition, many advanced models have been developed to screen and rank EOR processes (40 studies based on the SPE papers). However, to the best of our knowledge, no study has been accomplished for gel technologies. The evaluation of polymer gels is basically a multiple screening problem in which all considered gel technologies are simultaneously assessed for a given field. Recall that conventional guidelines lack ranking functionality and might produce contradictory results in such situations (i.e., multiple screening).

The first polymer gel screening guidelines were provided for colloidal dispersion gels by Mack (1978). They are based on three Minnelusa formation projects in Wyoming when these gels were still being applied in their sequential forms. Mack (1978) mentioned that if the sweep efficiency is poor (ultimate oil recovery < 33%), then the water oil ratio is not a limiting factor in choosing a candidate for this technology. Williams and Pitts (1997) accompanied their inventory of EOR projects in the Rocky Mountain region by screening criteria for thermal, gas, and chemical methods including polymer flooding, BGs, and CDGs. Their review was based on only two CDG projects and includes only some experts' opinions that were of polymer flooding except reservoir permeability. The upper validity limit of oil viscosity was extended to 400 cp which is not consistent with all other screening studies. Manrique et al. (2014) presented the most updated screening criteria in the form of a field applications review for CDG projects in the United States, Argentina, and Colombia since 2005. Their summary includes five screening parameters, six treatment-operational aspects, and qualitative descriptions of the frequently considered aspects in the evaluation of polymer gels in common. A summary of the CDG screening criteria and project reviews is presented in Table 2.9.

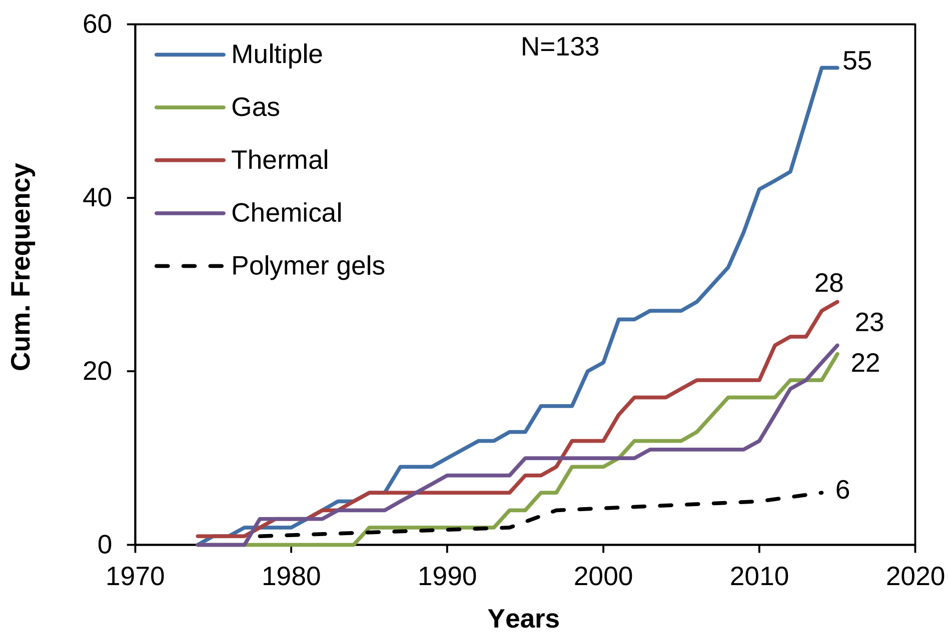


Figure 2.20. Comparison of Numbers of Screening Criteria for EOR Methods

Table 2.9. Summary of Screening Criteria for Colloidal Dispersion Gels

Parameter	Mack		Williams and Pitts		Manrique et al.	
	Min	Max	Min	Max	Min	Max
Survey Years	1974	1978	1994	1996	2005	2014
# of Projects	3		2		31	
Publishing year	1978		1997		2014	
Lithology	Sandstone		Sandstone		Sandstone	
Formation type	Matrix		Matrix		Matrix	
Permeability, md	10	300	50	-	10	4200
DPc, fraction	0.6	-	-	-	0.55	0.7 *
Temperature, °F	-	220	-	200	80	210
Average Net Pay, ft	-	-	NC	NC	20	200
Depth, ft	-	-	-	9000	-	-
Oil Sat. (start),%	-	-	-	-	-	-
Oil Viscosity, cp	-	-	-	400	5	30
Oil Gravity, API	-	-	15	40	-	-
Water Salinity, kppm	-	100	Acceptable		-	-
Water Cut, %	NC	NC	-	-	-	-
Mobility Ratio	-	-	-	-	-	-
Oil Recover (start), %	-	33	-	-	-	-

* From Castro et al. (2013)

For bulk gels, Table 2.10 shows that only three screening criteria were developed as well. Seright and Liang (1994) presented screening criteria for bulk gel applications in production and injection wells based on the field trials survey from 1980 to 1992 and the views of gel vendors and industry experts. In the DOE report form of this study, Seright (1993) provided extensive comparisons of BG treatments with polymer floodings and qualitative candidate selection criteria for both production and injection wells. It is important to note that in this study and others (Taber et al. 1997), the early-sequentially-injected CDG projects have been considered polymer floodings. Delgadillo (2010) proposed screening criteria for BGs based on lab evaluations and field applications and established a procedure for testing the technical feasibility of gel treatments. The author mentioned that current oil saturation is the most important criterion and should be > 10%. Williams and Pitts (1997) also considered BGs in their inventory of EOR projects in the Rocky Mountain region as mentioned above. Four BG projects were summarized in their study and some criteria were adopted from Taber et al. (1996). In addition, five frequently considered parameters in EOR screening were reported as not critical for bulk gels.

It has been identified that the previous polymer gels screening criteria suffer from the following lacks and drawbacks:

1- Only MCAP-BGs and CDGs have been evaluated where few unspecialized, limited parameters, single agent criteria or surveys have been published. This eliminates the possibility of evaluating multiple agents at the same time which is really important in reservoirs that exhibit different heterogeneity forms.
2- Only one study has presented conventional screening criteria in their complete statistical structure necessary to deal with the considerable data variabilities.
3- Most studies considered few reservoir/fluids characteristics and some parameters presented in form of expert's opinions such as oil viscosity < 200 cp due to the lacks of data.

Table 2.10. Summary of Screening Criteria for Metallically-Crosslinked Bulk Gels

Parameter	Seright and Liang		Williams and Pitts		Delgadillo	
	Min	Max	Min	Max	Min	Max
Survey Years	1980	1992	1990	1996	-	-
# of Projects	114		4		-	
Publishing year	1994		1997		2010	
Formation type	Carbonate Sandstone		Carbonate Sandston		Carbonate Sandstone	
Polymer type	HPAM, Xanthan, Others		HPAM		HPAM	
Permeability, md	4.1	5000	NC	NC	15	-
DPc, fraction	-	-	-	-	0.63	-
Temperature, °F	64	240		<250	-	208
Average Net Pay, ft	-	-	NC	NC	-	-
Depth, ft	-	-	-	11000	-	8000
Oil Sat. (start),%	-	-	-	-	10	-
Oil Viscosity, cp	-	-	NC	NC	-	200
Oil Gravity, API	-	-	NC	NC	18	-
Water Salinity, kppm	-	-	Acceptable		-	70
Water Cut, %	9	99.4	-	-	-	-
Oil Recover (start), %	1.1	73	-	-	-	-

4- Except two experts' opinions for Dykstra-Parsons coefficient (DPc), permeability variation and mobility ratio are not evaluated in these studies, despite the fact that these properties represent the roots of reservoir conformance problems.

5- No distinction has been recognized in the previous criteria between BG and WG gel systems despite the clear differences in their application objectives and volumes.

6- Some studies are field application reviews that summarized few screening parameters and sometimes no subsequent updates have been provided as with other EOR methods.

7- Some studies considered different combinations of polymers and crosslinkers, i.e. xanthan, polyacrylamide and other materials in one screening criteria.

8- Some criteria considered the same parameters commonly processed for other EOR methods while screening of polymer gels requires the consideration of other influential aspects like drive-fluid channeling characteristics.

9- Most criteria are generally biased to Wyoming oilfields and specifically to the Rocky Mountain region and Big Horn basin fields as projects in these regions are the sources of the data.

2.10.2. Qualitative Well Candidate Selection Criteria. This type of criteria facilitates the nomination of a well in a field for the application of a gel technology based on its functionality requirements. In other words, they represent qualitative well zoning criteria discussed in Section 2.4.

Seright and Liang (1994), and Manrique et al. (2014) accompanied their conventional screening criteria by qualitative candidate selection guidelines for BGs and CDGs. In addition, Sydansk and Southwell (2000), Smith (1999), Ricks and Portwood (2000), Wouterlood et al. (2002), and Romero et al. (2003) have provided several fundamental candidate selection criteria for BGs based on their extensive field experiences. Montoya Moreno et al. (2014) summarized the above bulk gels criteria in the following six points:

1- Quantifiable mobile oil saturation: a primary and secondary oil recovery factor less than 33% is sometimes used as a rule of thumb. This criterion is frequently satisfied in naturally fractured reservoirs with injector-producer fracture communication.

2- Rapid injection water breakthrough: water channeling can be identified using production data and water injection profiles surveys.

3- Injector-producer connectivity: geological models, chemical tracers and production data are examples for data sources that can be utilized to confirm reservoir connectivity.

4- Reservoir heterogeneity: core studies, electric logs, development of a dynamic geological model and, of course, fluid production data are some of the data sources used to quantify heterogeneity.

5- High connectivity: high injection rates and low injection pressures are indicative of water channeling. Gel treatments will normally increase injection pressure; therefore, a pressure margin must be available before the gel treatment. The injection pressure in the candidate well must also be significantly below the maximum waterflood plant injection pressure.

6- Mechanical integrity: casing and cement in the candidate well should be evaluated and confirmed to be in good condition. Cement bond logs are one common tool to rule out water channeling behind pipe.

Manrique et al. (2014) mentioned that some of the variables that frequently considered for evaluation of CDG technology are:

1. Maturity of the waterflood (evaluation of evidence for presence of remaining moveable oil).
2. Waterfloods operating under adverse mobility ratios.
3. Low reservoir permeability with substantial heterogeneity.
4. Thin reservoirs (net pay thickness < 40 ft) injecting water with several wells.
5. Potential injectivity constraints due to narrow margin between maximum injection and reservoir pressures (assumes injection below parting pressure).
6. Limited water handing capacities.
7. Requirements to minimize or delay polymer production.

It can be easily recognized that there is a considerable ambiguity in the above criteria about several issues in addition to being quite general. For instance, where the quantifiable mobile oil should be present in the reservoir so that polymer gels effectively improve the sweep efficiency? Secondly, what is the role of the above qualitative criteria in the selection process of gel technologies and how they are connected to the numerical guidelines? A number of points are common for both gel systems like substantial heterogeneity, waterfloodings, and adverse mobility ratio. Finally, from another prospect, rating of gel technologies for a conformance problem seems impossible using such quite general descriptive statements. To sum up, the above well candidate criteria look like a check list by the requirements that should be verified for a gel system after selecting it.

2.10.3. Conformance Problems Classification. It has been remarkably indicated that the conformance problem classifications are the most applied selection criteria for the conformance improvement technologies in general (agents or operations). In addition, well candidate selection criteria have been simultaneously utilized with the problem classifications in some case histories to accelerate the selection process. Among well candidate selection criteria, the point of existing of quantifiable oil reserves is the most cited criterion. Before examining problem classification studies, it is very important to know what issues have called for such type of qualitative approaches.

As illustrated in the previous sections, conformance problems comprise a wide range of issues that have different mechanisms, locations, and forms. In such situations, problem categorization would greatly facilitate the interpretation and identification of conformance issues. In addition, the properties of conformance problems are qualitatively evaluated using several costly diagnosing techniques. In this evaluation, several qualitative descriptions are used like strong channeling problem or laterally extended channel and so no. The subjective nature of this evaluation imposes an intuitive judgment on conformance improvement technology selection process (i.e., to be performed qualitatively also). Therefore, several studies have focused on the classification and connection of conformance problems and conformance solutions to ease the selection process (Borling et al. 1994; Wu et al. 1994; Azari and Soliman, 1996; Dalrymple, 1997; Sydansk and Southwell, 2000; Creel et al. 2001; Seright et al. 2001; Kabir, 2001; Smith and Ott, 2006; Liu et al. 2006; Joseph and Ajienka, 2010, Liu et al. 2010; Jaripatke and Dalrymple, 2010; Kim and Crespo, 2013).

Three distinct development stages have been identified for the selection process based on the categorization aspects of conformance problems presented in the above studies. In each stage, an additional new aspect was used as a classification criterion for the conformance issues as shown in Figure 2.21. This means that the conformance issues are reviewed according to all these aspects in an integral way to facilitate the solution identification. The trigger for this progressive development was mainly the comprehensive experiences that were continuously gained as more water management projects performed during each stage. In the following points, classification studies and aspects are chronologically summarized as follows:

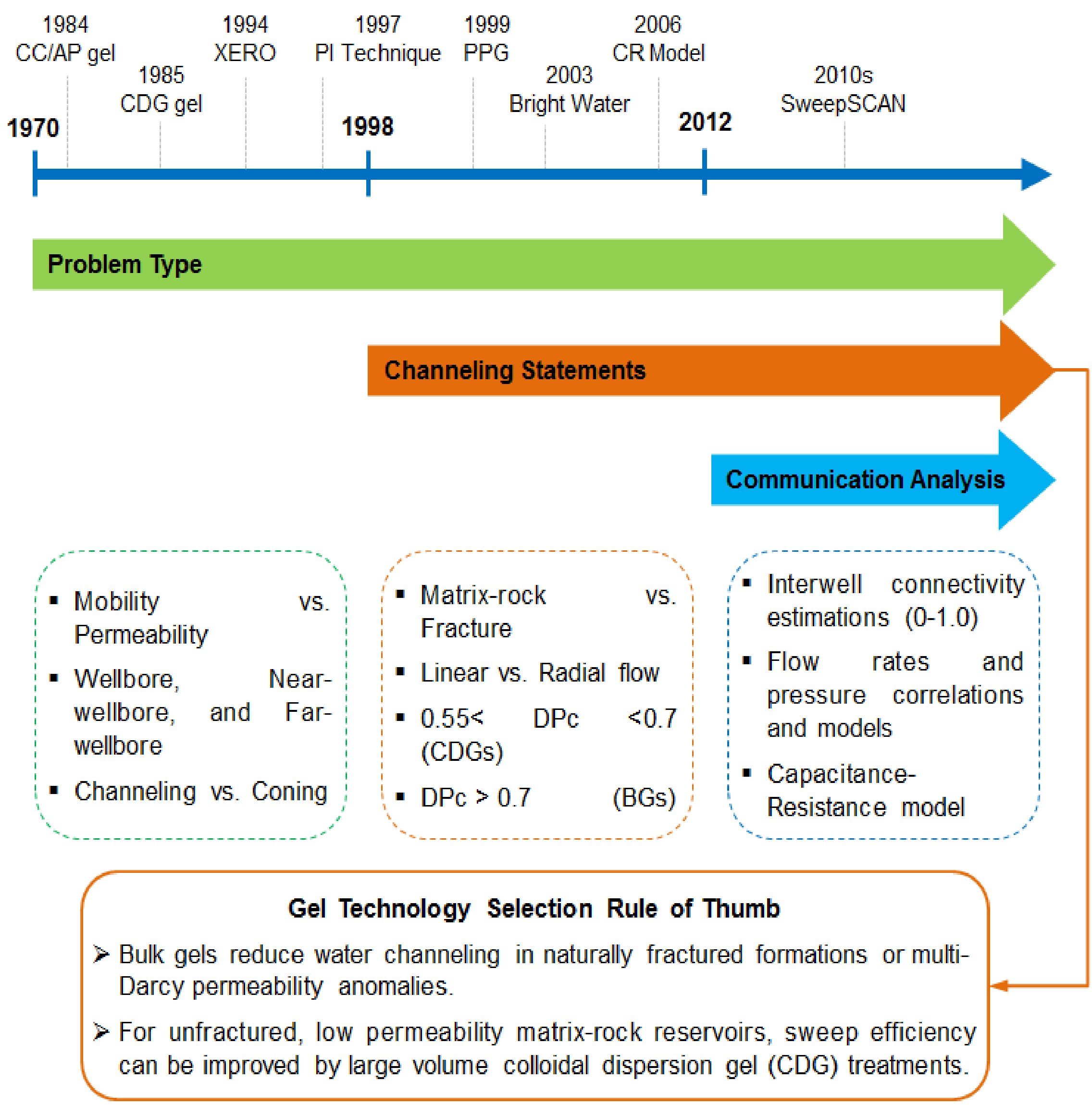


Figure 2.21. Development Stages of Conformance Agent Selection Process

1- Problem type: This stage started in 1970s when the water management practices started to receive great attention in oil industry and some new promising conformance technologies were developed. The type or nature of the problem was the criterion used to match a conformance issue to a conformance improvement technology. For instance, high permeability strata without crossflow problem can be treated by either mechanical techniques or polymer gels. In other words, conformance problems have been categorized and related to conformance improvement technologies based on their engineering considerations of both. Problems considerations generally includes problem locations (near vs. far wellbore), problem mechanisms (channeling vs. coning), and the presence of adverse mobility ratio and crossflow. Conformance problem types presented in Section 2.3 are a genuine example for the problem-type classification studies. The overwhelming usage of the term “problem identification” provides clear evidence that the problem type was the selection criterion of conformance solutions.

Several conformance approach reviews (Azari and Soliman, 1996; Soliman, 1999; Soliman et al. 2000; Creel et al. 2001; Kabir, 2001; Joseph and Ajienka, 2010, Liu et al. 2010; Jaripatke and Dalrymple, 2010; Kim and Crespo, 2013), selection process logic chart (Borling et al. 1994), and expert systems (Wu et al. 1994; Dalrymple, 1997) were established using problem type (Table 2.11, Figure 2.22 and Figure 2.23). During this time period, the understanding of conformance problems has been significantly improved and extensive experiences were gained as new conformance technologies and especially polymer gels were tested for a variety of issues. The problem with this general categorization was that some conformance improvement technologies like polymer gels have been verified to be a solution for a number of conformance issues with quiet different designs and practices. For example, both BGs and CDGs or polymer flooding were applied in some case histories, the matter that called for more differentiating classifications.

Table 2.11. General Conformance Decision Matrix (Dalrymple, 2010)

Conformance Problems	**Cement**	**UF Cement**	**Monomer Gels**	**BGs MCAP**	**BGs OCAP**	**RPM**	**PPG**
Plug-back	X						
Plugging well	X						
Bottom water shutoff				X	X		
Casing leaks		X	X	X			
Channel behind pipe		X	X	X			
Seal high pressure zone			X		X		
Potential acid into water						X	
Potential frac into water						X	
Coning/cresting			X	X	X	X	
Channel from injector			X	X	X	X	X
Water shutoff in a GP				X	X		
High-permeability streaks			X	X	X	X	X
Large void	X						X
No shale barrier						X	

UF: ultra-fine, BGs: bulk gels, MCAP: metallically crosslinked polyacrylamides, OCAP: organically crosslinked polyacrylamides, RPM: relative-permeability-modifiers, PPG: preformed particle gels.

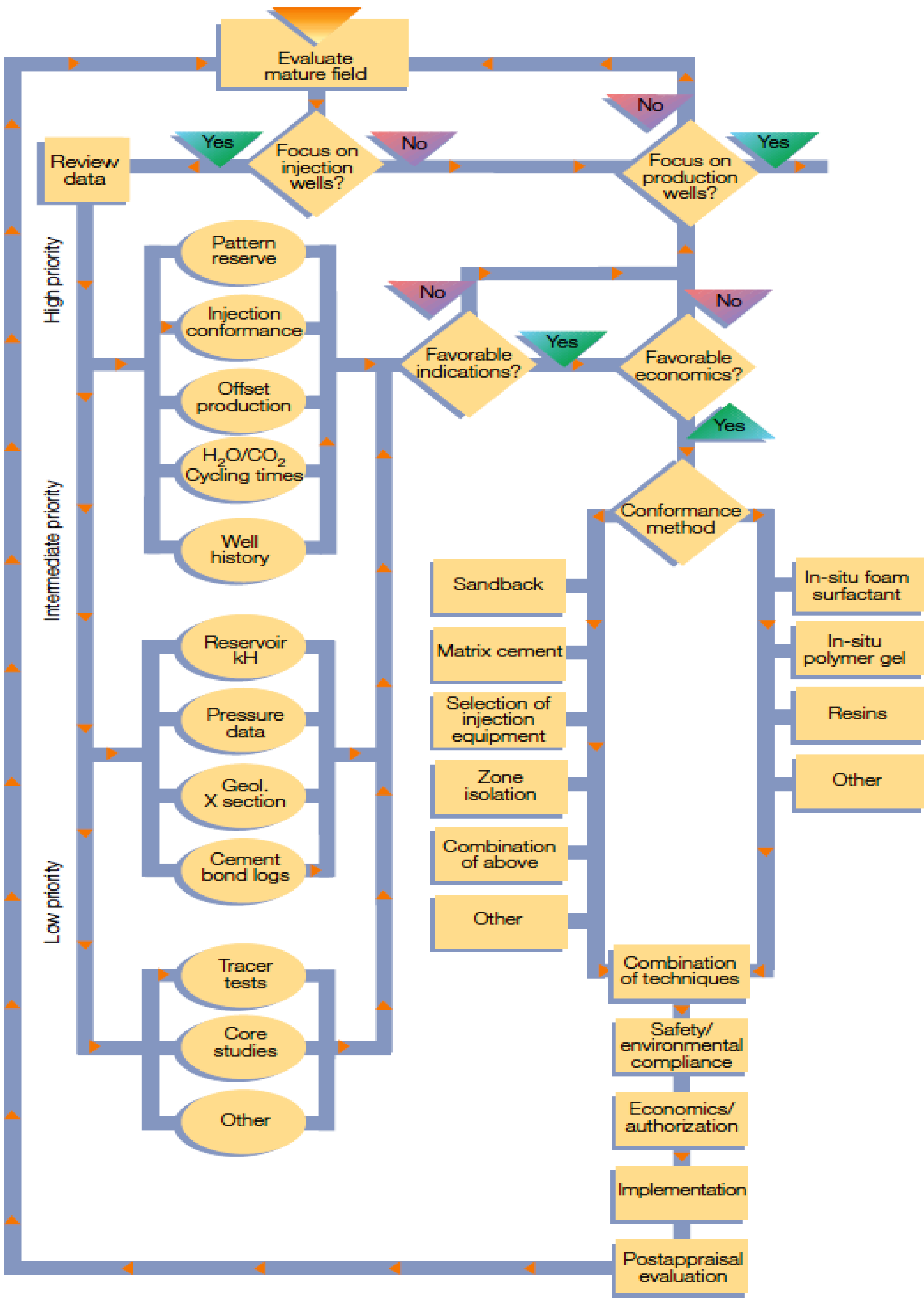


Figure 2.22. Amoco’s Process Logic for Matching Conformance Problems and Solutions (Borling, 1994)

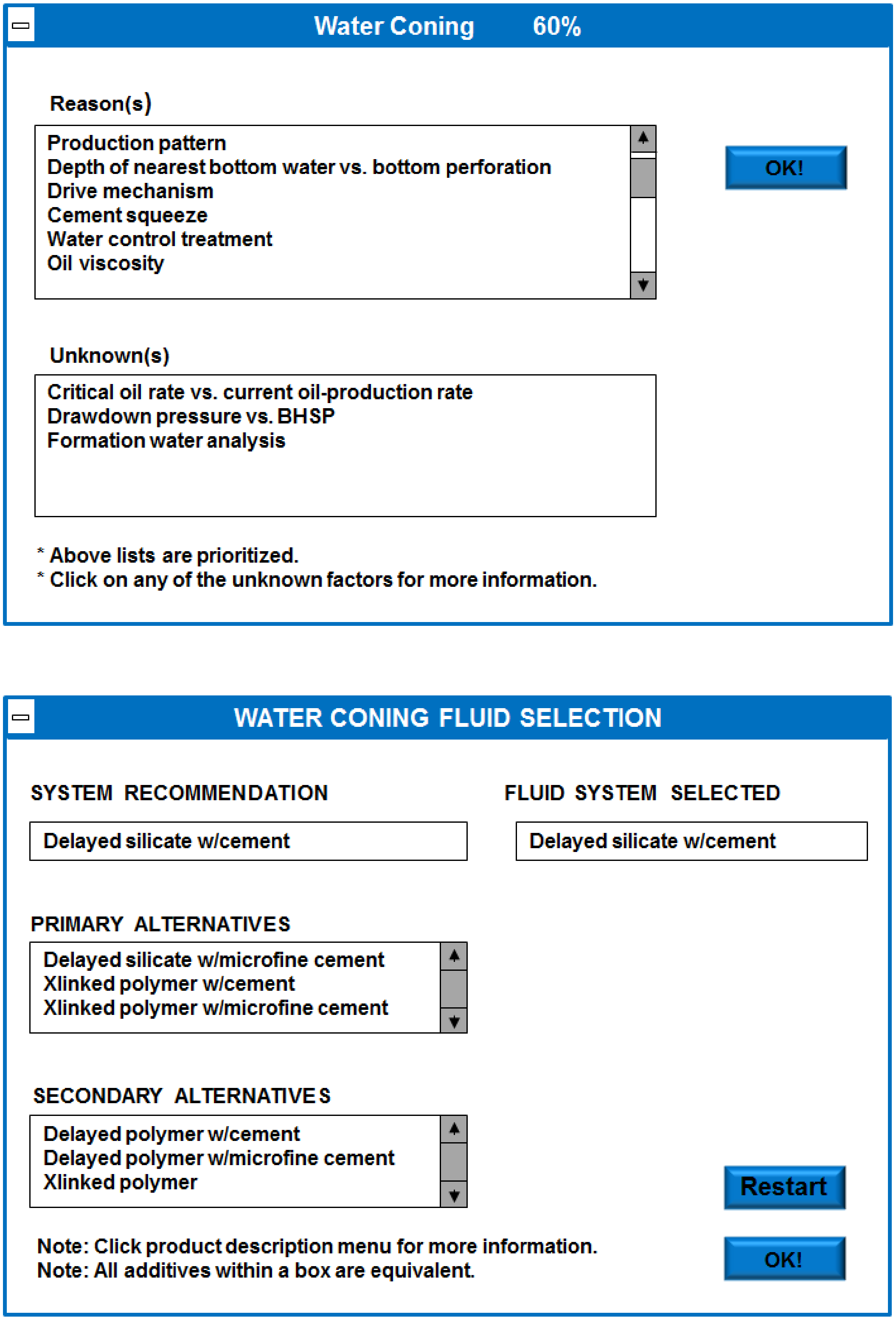


Figure 2.23. Problem Identification and Fluid Selection Screens of Water Control Expert System (Wu et al. 1994)

2- Channeling statements: After the emergence and extensive testing of some new promising conformance chemistries and agents, more comprehensive reviews of conformance problems have been introduced (Sydansk and Southwell, 1998, Southwell, 1999, Creel et al. 2001, Seright et al. 2001, Kabir, 2001, Smith and Ott, 2006). In addition to problem type, these studies have taken into considerations the problem severity or drive-fluid channeling strength in terms of some statements. This problem characteristic has been considered only for one purpose that is to assist in the designation of well candidates with strong channeling to be treated by bulk gels. However, this problem property (i.e., channeling strength) has been qualitatively treated as well due to the absence of adequate characterization system for conformance problems. Furthermore, one of these channeling statements has been modified later into a selection rule of thumb specifically for polymer gels. In the following paragraphs, the above studies and developments are presented in more details. Their limitations and consequences on conformance improvement technology selection will be also discussed.

In 1998, Sydansk and Southwell provided a list of the conformance problems that can be treated by Chromium (III)-Carboxylate/Acrylamide-Polymer (CC/AP) bulk gels as shown in Table 2.12. They have also illustrated that there are two problem key distinctions that must be made in order to identify the appropriate treatment. First, a conformance problem should be differentiated whether it is a vertical or areal issue and whether there is fluid crossflow between geological strata or not. The second key distinction is whether the high conductive zone is simple high permeability unfractured matrix rock (< 2000 md) or it is a high permeability anomaly such as fractures (> 2000 md). The second key was an attempt to assess the problem severity whether it involves strong or weak channeling strength. This means that in addition to the problem type, they categorized conformance problems according to the formation type as an indicator of drive-fluid channeling strength. Based on these distinctions, BGs can successfully treat vertical, no crossflow, and fracture type conformance problems because they are strong gel systems.

Table 2.12. Conformance Problems That are Attractive to Treat With Bulk Gels (Sydansk and Southwell, 2000)

Matrix Conformance Problems	
Without crossflow	Yes
With crossflow	Challenging—must place very deeply
Fracture Conformance problems	
Simple	Depends— case-by-case basis
Network—intermediate intensity and directional trends	Yes
Network—highly intense	Often not
Hydraulic	Yes
Coning Problems	
Water and gas via fractures	Yes
Water and gas via matrix reservoir rock	No
Behind Pipe Channeling	Yes, for microflow channels
Casing Leaks	Yes, for microflow channels

Seright et al. (2001) classified water production problems into four categories based on the conformance treatment type and ranked them in term of the remediation difficulty (Table 2.13). They also proposed a diagnostic strategy to decide whether the fluid flow around the wellbore is radial or linear to be the second channeling statement (Section 2.4.2). Smith and Ott (2006) presented a Comprehensive Conformance Problem Matrix that classifies conformance issues with respect to two aspects. First, problems were categorized into wellbore versus far-wellbore problems and secondly into high flow conduit versus permeable rock problems based on the severity of the drive-fluid channeling. In 2016, Smith updated his matrix by connecting conformance problems into conformance improvement technologies as shown in Figure 2.24 (Mishra et al. 2016).

Table 2.13. Excessive Water Production and Treatment Categories (Seright et al. 2001)

<u>Category A:"Conventional" Treatments Normally Are an Effective Choice</u>

1. Casing leaks without flow restrictions.
2. Flow behind pipe without flow restrictions.
3. Unfractured wells (injectors or producers) with effective barriers to crossflow.

<u>Category B: Treatment with Gelants Normally are an Effective Choice</u>

4. Casing leaks with flow restrictions.
5. Flow behind pipe with flow restrictions.
6. "Two-dimensional coning" through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

<u>Category C: Treatment with Preformed Gels Normally are an Effective Choice</u>

8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

<u>Category D: Difficult Problems Where Gel Treatment Should Not Be Used</u>

11. Three-dimensional coning.
12. Cusping.
13. Channeling through strata (no fractures), with crossflow.

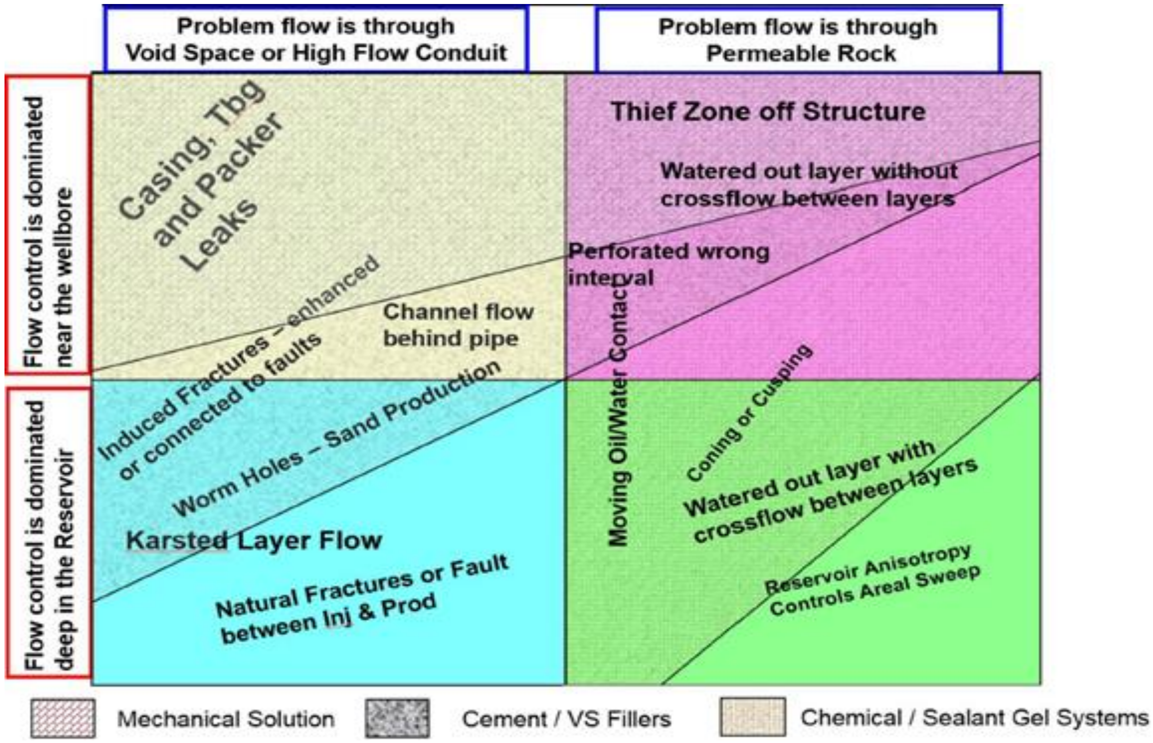


Figure 2.24. Comprehensive Conformance Problem and Solution Matrix (Mishra et al. 2016)

However, the above qualitative selection matrices have mainly considered bulk gels and based on the Permian and Powder River Basins' experiences. They have ultimately concentrated on distinguishing of the suitable conditions to apply BGs and on the sizing of the bulk gel treatments. The flood-size treating technologies (CDGs and WGs) have been rarely taken into consideration in these studies where only Sydansk (2007) pointed out to such conformance agents among above studies. He provided that there are some reports in the literature mentioned that large volume CDG treatments were applied to treat matrix-rock reservoirs with crossflow.

Later, some researchers have considered CDGs and some other gel systems in addition to BGs and new channeling statement appeared in the term of permeability variation. For example, Liu et al. (2006 and 2010) presented conformance problems in Chinese oilfields, and connected them with a variety of treating agents based on the type of the conformance treatment. They have considered BGs, CDGs, WGs and performed-particle gels in their study, and provided a comprehensive decision-making strategy for the candidate well selection. Reynolds and Kiker (2003) suggested the injection of CDGs at the inception of waterflooding if analogous floods suggests a premature water breakthrough or Dykstra-Parsons coefficient (DPc) is greater than 0.6. They proposed the injection of BGs after waterflooding initiation if water channeling is through fractures or high permeability streaks. The ICP (Instituto Colombiano del Petroleo) developed a methodology to select the possible solutions for improving sweep efficiency in Columbian oilfields that presented by Castro et al. (2013) and Maya et al. (2014). In this methodology, DPc has been introduced as a key parameter to guide the selection process where it suggests application of CDGs if $0.55 < DPc < 0.7$ and application of BGs for reservoirs with DPc values > 0.7.

2.1- Sydansk and Southwell rule of thumb: Among the above studies, the formation type–based channeling statement introduced by Sydansk and Southwell (1998) was the most acceptable criteria in the practical points of view for many gel service companies. Therefore, this statement has been translated into the following well-known rule of thumb for gel technology selection in history case studies. This rule states that bulk gels are designed to reduce water channeling in extreme heterogeneities like naturally fractured formations or in reservoirs with multi-Darcy permeability anomalies. For unfractured, low permeability matrix-rock reservoirs, sweep efficiency can be improved by large volume colloidal dispersion gel (CDG) treatments (Mack and Smith, 1997; Al-Dhafeeri et al. 2005; Norman et al. 2006; Muruaga et al. 2008; Diaz et al. 2008). It is noteworthy that they justified the utilization of the CDGs by the presence of crossflow between reservoir layers.

2.2- Limitations: Despite the noticeable progress witnessed during this stage in the selection of guidelines conformance improvement technologies, some limitations were identified in the above studies. The most important limitation in these qualitative statements that they do not allow to rate both conformance problems and improvement technologies.

For gel field projects reviewed in the present study, the distribution of lithologies, formation types, and reservoir permeability are shown in Figure 2.25 and Figure 2.26. The first figure illustrates that BGs were applied in matrix-rock reservoirs more than in naturally fractured systems (29 vs. 20). In addition, the second figure shows that CDGs and WGs were applied in matrix-rock reservoirs that have higher average permeabilities than BG matrix-rock trials. Thus, if it is stated that BG matrix-rock case histories have high permeability anomalies, the above observation would imply that CDG projects have higher permeability anomalies than BGs under the assumption of correlating average and high permeability values for the reviewed reservoirs. This implies that formation-based Sydansk and Southwell rule of thumb cannot be used anymore after the extensive application of BGs in matrix-rock reservoirs.

Concerning Darcy law-based diagnosing method proposed by Seright et al. (2001), the considerable uncertainties in reservoir properties result in conflicts with the field observations in many situations (Romero et al. 2003; Norman et al. 2006). This matter has limited the application of this method in history case studies to a great degree.

The problem matrix introduced by Smith and Ott (2006) does not go further than other former studies because they used the problem type again as an indicator of channeling strength. For gel selection methodologies that based on the permeability variation (Reynolds and Kiker, 2003 and Castro et al. 2013), Figure 2.27 shows that DPc application intervals for polymer gels are intersected over wide intervals and a large number of CDG treatments were applied in formations with DPc > 0.7. This indicates a clear conflict with ICP criteria that have preserved this range (DPc > 0.7) for bulk gel applications; thus, these criteria are only regional-decision-making rule.

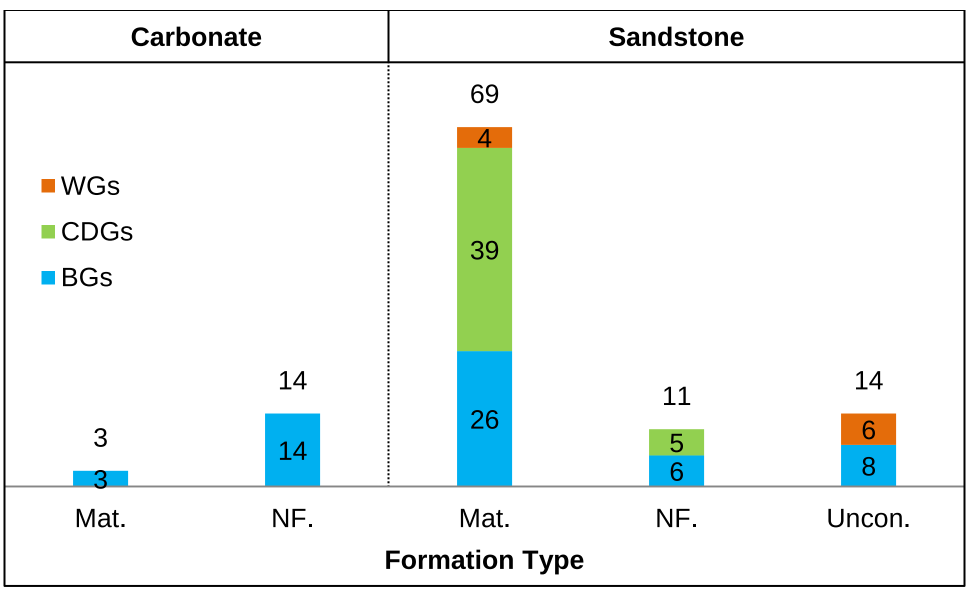


Figure 2.25. Distributions of gel projects according to reservoir types

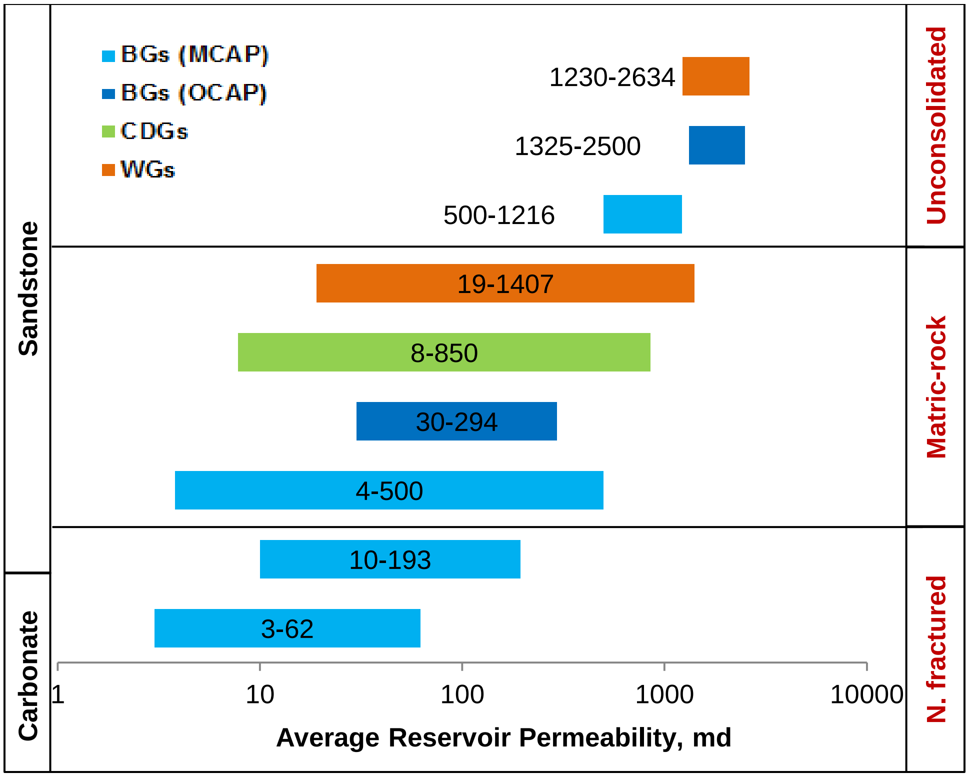


Figure 2.26. Comparison of average permeability applicability ranges for gel systems

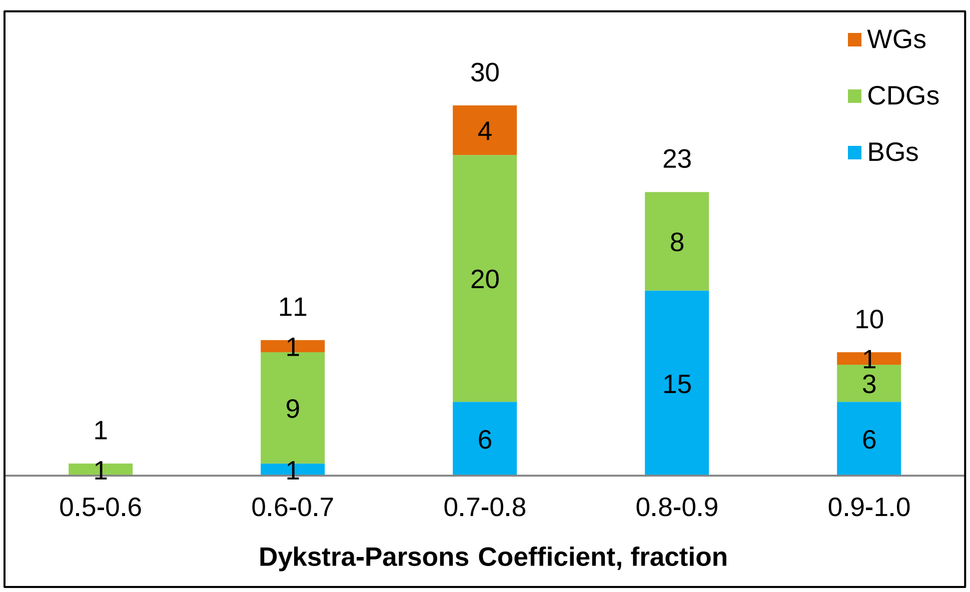


Figure 2.27. Permeability variation coefficient distributions for polymer gel projects

3- Communication analysis: In this stage, the communication analysis techniques started to be used to characterize the channeling strength between injectors and producers in a quantitative accurate manner. The interwell connectivity is frequently represented by correlation factors or weighting coefficients of water injection and production rates. The interwell connectivity is ranging between 0 and 1.0 with 1.0 means strong communication and 0 no communication. The estimation of interwell communication enables the identification and ranking of injectors and producers for conformance treatments (well zoning). It is important to note that correlations of injection and production cycles in the case of CO_2 injection and of flow rates or pressures have been previously observed (Borling, 1994, Love et al. 1994; Lantz and Muniz, 2014). However, such observations have been qualitatively utilized to evaluate the channeling strength, connected wells, and ranking of offending well patterns.

Chou et al. (1994) employed correlation coefficients between water injection and production rates to identify the problematic injectors in the case of the Eunice Monument South Unit (EMSU). The problem wells were ranked according to the estimated correlation coefficients and the injectors with > 0.5 coefficients were selected for bulk gel treatments as shown in Figure 2.28. They provided that results show that offset producers having a high correlation coefficient with the pattern injector generally have positive response after bulk gel treatments, and vice versa. In addition, they provided that performances of gel treatments applied in injection wells nominated based on these analyses are much better than previous remedies in the Eunice Monument South Unit.

Baker et al. (2012) examined 12 waterflooded oilfields with over 2000 injector-producer pairs in Western Canada using SweepSCAN communication analysis program

(Baker Hughes SweepSCAN™, 2012). The goal of this examination was to verify the presence of induced fractures that cause the strong communication between injection and production wells. They suggested bulk gel treatments as one of the good reservoir management practices for small fracture volumes. Sandhu (2012) reported the utilization of Epic Communication Analysis software to select gel treatment candidates the case of in Weyburn Midale oilfield. It is important to mention that this history case has been identified as one of three BGs gel projects that are considered as overperform treatments.

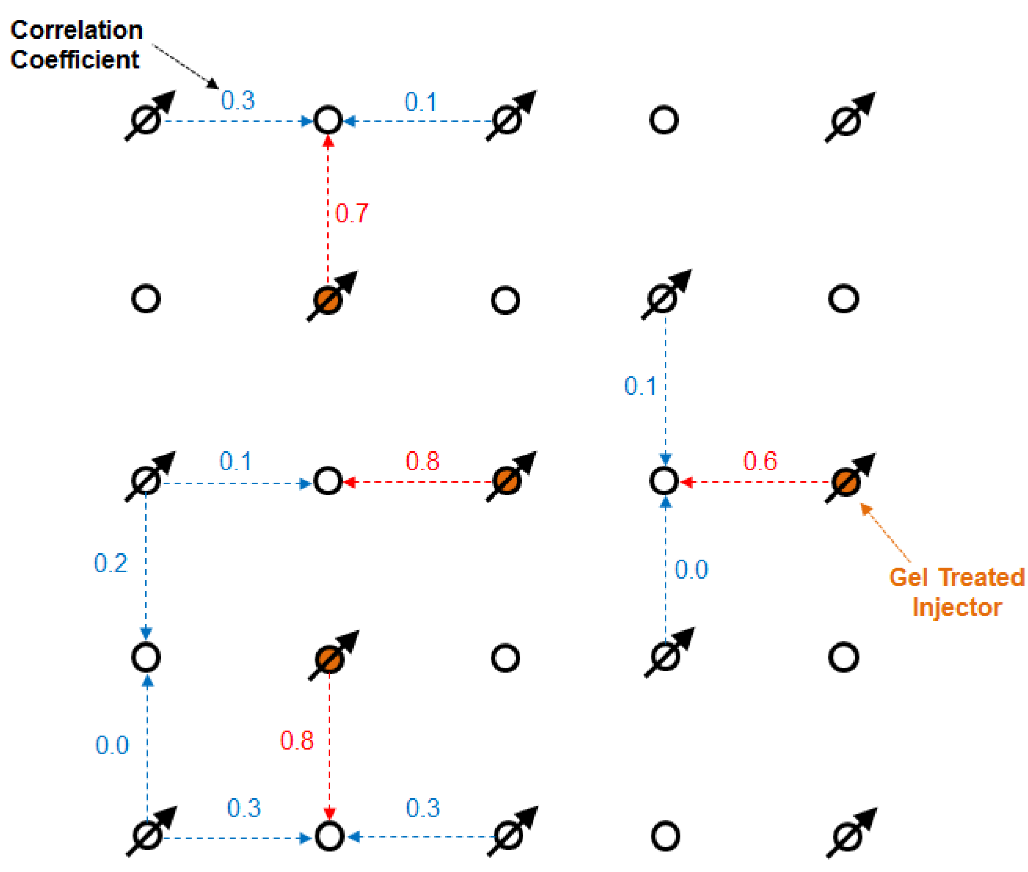


Figure 2.28. Schematic Map of Gel Treated Injectors in EMSU Field (Chou et al. 1994)

Once more, the development efforts were focused only on identifying strong channeling problems that are suitable to be remedied by bulk gels. In addition, other conformance problem characteristics have not been taken into considerations because these studies focused on rating of well patterns for strong plugging agents like cement and bulk gels.

In conclusion, the above review clearly illustrates that the selection process of conformance improvement technologies and especially polymer gels has mostly been nominally performed using the problem type or description according to some classification aspects. In addition, the choice of the gel technologies has been solely based on the drive-fluid channeling strength while it involves other important factors that should be considered as well. While all studies have emphasized the importance of existing producible oil quantities in problematic well patterns, no clarifications were made about in which zones there quantities should be present. Furthermore, the development of reservoir heterogeneities or channeling degree with time or injection process has also not been indicated in these studies.

This judgmental channeling-based approach has resulted in the emergence of many diverging opinions about the applicability of polymer gels as shown in Table 2.14 (Chou et al. 1994). There have been more qualitative problem descriptions and terminologies than the conformance problems themselves. Furthermore, it has resulted in a difficulty in the recognition of distinctive channeling severity limits for gel systems. Consequently, conformance problems in all reviewed case histories were characterized as strong channeling issues even issues that were treated by weak gel systems.

Table 2.14. Some Proposed Cut-offs for Diagnosis Parameters of Drive-fluid Channeling Strength

Parameter	Weak Channeling	Strong Channeling	Reference
Problem Zone Permeability	< 2000 md	> 2000 md	Sydansk & Southwell (2000)
	<10 Darcies	> 10 Darcies	Sydansk (2007)
Permeability Contrast	$K_{Streak} > (2\text{-}10)\ K_{Matrix}$	$K_{Streak} > (50)\ K_{Matrix}$	Baker et al. (2012)
	$K_{high} < 1000\ K_{Matrix}$	$K_{high} > 1000\ K_{Matrix}$	Sydansk (2007)
Permeability Variation	DPc > 0.6	-	Reynolds and Kiker (2003)
	0.55 < DPc < 0.7	DPc > 0.7	Castro et al. (2013)
Drive-fluid Injectivity	< 10 bpd/psi	> 20 bpd/psi	Pipes & Schoeling (2014)
	-	> 5 Expected [1]	Tweidt et al. (1997)
Recovery factor	-	< 33 %	Montoya Moreno et al. (2014)
Flow Regime	Radial	Linear	Sydansk (2007)
Interwell Communication[2]	< 0.5	> 0.5	Baker et al. (2012)
Formation Type	-	Naturally Fractured Unconsolidated	Current Study
Drive-fluid Breakthrough Time	Months to years	Weeks to Months	Current study
Tracer breakthrough Time	Weeks to Months	Hours to Days	Current study
Water Cut Increment Rate	< 0.5 per year	> 0.5 per year	Current Study

(1) Based on average reservoir parameters, (2) correlation coefficient of producer-injector pressures or flow rates.

2.11. LITERATURE REVIEW DISCUSSION

The above literature review reveals that the subjective nature of conformance problem evaluation imposes many difficulties toward rating and connecting of conformance problems and conformance solutions. It caused emergence of three different approach studies for solution selection and no clear explanations about the role of each approach in the selection process have been provided. The review also illustrates that these studies have separately handled gel systems, the matter that resulted in absence of comprehensive comparative guidelines.

Consequently, a rule of thumb for gel technology selection was developed based on conformance problems classifications established from field experiences. This resulted in impediment of other proposed guidelines and criteria where they were rarely used in gel field projects. In this rule, conformance solutions and specifically polymer gels are chosen according to channeling-strength-based statements in terms of problem description, formation type, or permeability variation. This judgmental approach has resulted in the emergence of many diverging opinions about the applicability of polymer gels (Chou et al. 1994). Furthermore, it has resulted in a difficulty in the recognition of distinctive channeling severity limits for gel systems.

The identification of polymer gels is basically a multiple screening problem in which all considered gel technologies are simultaneously assessed for a given field. However, no applicability screening criteria have been established for OCAP-BGs and weak gels. The available guidelines for MCAP-BGs and CDGs suffer from many deficiencies like update data, expert opinions, and the inclusion of limited number of screening parameters. Being the roots of conformance issues, permeability variation and mobility ratio should be included in the applicability guidelines of gel systems. The existence of several versions of gel technology applied over a wide range of application conditions call for more sophisticated models to screen and selection them.

The evolution of three different approach studies that have an interrupted appearance in history case studies indicate the sophistication of gel technology selection and a lack of the sound understanding of this process. Also, the absence of the connection between these studies indicates that the steps or components of identification process are not fully understood. Furthermore, the evaluation of other conformance problem aspects in history case studies highlights that these characteristics have influential roles in the selection process just like channeling strength. The ambiguity existing in the descriptive candidate selection criteria diminishes the distinctions between conformance problems which in turn complicates gel technology identification routine.

PAPER

I. Comprehensive Guidelines for the Application of In-Situ Polymer Gels for Injection Well Conformance Improvement Based on Field Projects

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Abstract

Polymer gels are increasingly applied to improve sweep efficiency of different IOR/EOR recovery processes. Three in-situ polymer gel systems including bulk gels, colloidal dispersion gels, and weak gels are often used to mitigate water production caused by reservoir heterogeneity and unfavorable mobility ratio of oil and injected fluids. Selecting the most appropriate gel system is a key component for a successful conformance improvement treatment. Screening criteria in terms of reservoir and fluid characteristics have been widely used to identify potential technologies for a specific reservoir. Despite the large number of polymer gel projects, only five, limited-parameters, single-agent criteria or surveys have been sporadically accomplished that suffer from many deficiencies and drawbacks.

This paper presents the first complete applicability guidelines for gel technologies based on their field implementations in injection wells from 1978 to 2015. The data set includes 111 cases histories compiled mainly from SPE papers and U.S. Department of Energy reports. We extracted missing data from some public EOR databases and detected potential outliers by two approaches to ensure data quality. Finally, for each parameter, we evaluated project and treatment frequency distributions and applicability ranges based on successful projects. Extensive comparisons of the developed applicability criteria with the previous surveillance studies are provided and differences are discussed in details as well.

In addition to the parameters that are considered for other EOR technologies, we identified that the applicability evaluations of polymer gels should incorporate the parameters that depict roots and characteristics of conformance issues. The present applicability criteria comprise 16 quantitative parameters including permeability variation, mobility ratio, and three production-related aspects. Application guidelines were established for organically crosslinked bulk gels for the first time, and many experts' opinions in the previous criteria were replaced by detailed property evaluations. In addition, we identified that the applicability criteria of some parameters are considerably influenced by lithology and formation types, and thus, their data were analyzed according to these characteristics. Besides their comprehensiveness of all necessary screening parameters, the novelty of the new criteria lies in their ability to self-check the established validity limits for the screening parameters which resulted from the inclusion and simultaneous evaluation of the project and treatment frequencies.

Introduction

Excessive water production represents a major industry challenge because of its serious economic and environmental impacts. The problem of producing and disposing of large quantities of injection water is becoming more crucial due to the tightening economic constraints caused by falling oil prices; hence, many operators reexamine their spending rates. Among the conformance improvement technologies, polymer gels have been proven to be effective in addressing this problem and in increasing oil recoveries. However, selection of a proper gel technology is not an easy task for operators and reservoir engineers fundamentally due to the existence of numerous types of the conformance problems and gel technologies, and because of the fact that the treatment of a specific conformance issue requires a distinct gel technology.

Reservoir engineers usually refer to screening criteria to identify potential EOR processes for a given reservoir. These criteria are established from real field applications of the EOR methods and summarized in terms of reservoir and fluid properties. In other words, EOR criteria represent the intervals of validity of each influential property based on successful field tests, engineering considerations, and experts' opinions (Alvarado and Manrique, 2010). Despite the large number of gel field projects, only five screening criteria have been sporadically accomplished for polymer gels as shown by Figure 1, which compares the number of screening criteria developed for some EOR techniques based on SPE papers.

The first polymer gels screening guidelines were provided for colloidal dispersion gels (CDGs) by Mack (1978) based on three Minnelusa formation projects in Wyoming when these gels were still being applied in their sequential forms. He mentioned that if the sweep efficiency is poor (ultimate oil recovery < 33%), then the water oil ratio is not a limiting factor in choosing a candidate for this technology. Manrique et al. (2014) presented the most updated screening criteria in the form of a field applications review for CDG projects in the United States, Argentina, and Colombia since 2005. Their summary includes five screening parameters, six treatment-operational aspects, and qualitative descriptions of frequently considered aspects in the evaluation of polymer gels in common.

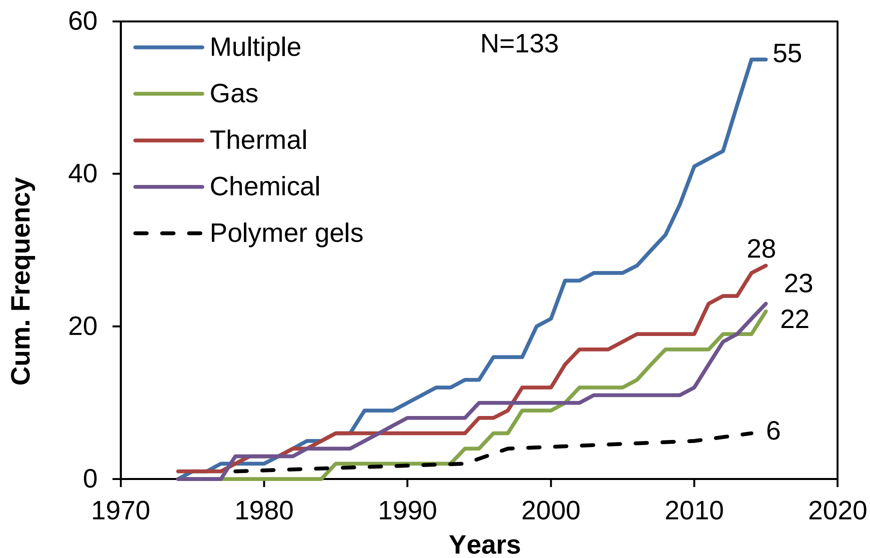

Figure 1. Development of screening criteria of polymer gels and common EOR methods

Seright and Liang (1994) presented screening criteria for bulk gel (BGs) applications in production and injection wells based on the field trials survey from 1980 to 1992 and the views of gel vendors and industry experts. In the DOE report form of this study, Seright (1993) provided extensive comparisons of BGs with polymer floodings, and qualitative candidate selection criteria for both production and injection wells. It is important to note that in this study and others (Taber et al. 1997), the early-sequentially-injected CDG projects have been considered polymer floodings. Delgadillo (2010) proposed screening criteria for BGs based on lab evaluations and field applications and established a procedure for testing the technical feasibility of gel treatments. The author mentioned that current oil saturation is the most important criterion and should be > 10%.

Williams and Pitts (1997) accompanied their inventory of EOR projects in the Rocky Mountain region by screening criteria for thermal, gas, and chemical methods including polymer flooding, BGs, and CDGs. They adopted some criteria from Taber et al. (1996) and five frequently considered parameters in EOR screening were reported as not critical for bulk gels. The aforementioned screening guidelines are elaborately presented and compared with the developed criteria in the last section of this paper.

We have identified that the previous polymer gels screening criteria suffer from the following lacks and drawbacks:

1. Few specialized screening studies have been produced and most of them were limited to one gel technology. This eliminates the possibility of evaluating multiple agents at the same time which is really important in reservoirs that exhibit different heterogeneity forms.
2. Most studies included few reservoir/fluids characteristics and some parameters presented with expert's opinions such as oil viscosity < 200 cp due to the lack of data.

3. Except two experts' opinions for Dykstra-Parsons coefficient (DPc), permeability variation and mobility ratio are not evaluated in these studies, despite the fact that these properties represent the roots of reservoir conformance problems.
4. Some criteria considered the same parameters commonly processed for other EOR methods while screening of polymer gels requires the consideration of other influential aspects like drive-fluid channeling characteristics.
5. No distinction has been recognized in the previous criteria between BG and WG systems even though the differences in their application objectives.
6. Some studies are field application reviews that summarize design aspects in addition to few screening parameters, which lack updated information.
7. Some screening studies comprise different combinations of polymer and crosslinking materials and consider then as one conformance system, i.e. xanthan, polyacrylamide and other materials.
8. Most criteria are generally biased to Wyoming oilfields and specifically to the Rocky Mountain region and Big Horn basin fields as projects in these regions are the sources of the data.

Evidently, there is an obvious shortage in the number and quality of screening studies for polymer gels in comparison with other EOR technologies. The objective of this study is to provide improved and updated applicability guidelines for three injection-well-treating-gel technologies based on their field trials published in SPE papers and DOE reports from 1978 to 2015. Tasks of collecting data, extracting missing values, and detecting outliers are briefly discussed. For each parameter, we will provide project and treatment distributions, guidelines in terms of various statistical attributes, and the favorable conditions that were determined through identifying the denser property range. Features of the new criteria will also be illustrated through extensive comparisons with the preceding studies.

Polymer Gel Conformance Technologies

Among the many other invented technologies, polymer gels have been proven to be an effective solution for a variety of conformance issues, especially in injection wells. They can effectively penetrate the offending high conductive zones deep into the reservoir and provide a sustainable diversion to subsequent injected water toward unswept, low permeability zones. Polymer gels are usually classified according to their ingredients, where the gelation process occurs, and the resulting gel structure. Synthetic polyacrylamide-based gels are the most widely applied chemical conformance-improvement system for treating injection wells (Lantz and Muniz, 2014). Polyacrylamides can be either organically (OCAP) or metallically (MCAP) crosslinked depending on type of the crosslinking agent used. In this paper, three partially hydrolyzed polyacrylamide, in-situ gelling conformance systems are considered for screening purposes.

Bulk Gels. Bulk gels (BGs) are probably the most widely applied polymer gel system for conformance improvement purposes (Sydansk and Southwell, 2000, Lantz and Muniz, 2014). These gels can be formed using high molecular weight (8-13 million Daltons) partially hydrolyzed polyacrylamides with a crosslinker. The high polymer concentrations result in a continuous semi-solid 3D network structure for the gel. Bulk gels provide a wide range of strengths and a wide range of controllable gelation times; thus, they can be applied to injection or production wells for profile control or water shut-off purposes.

This gel system has two versions depending on the type of crosslinking agent. For MARCIT gels developed by Marathon Oil Company, polyacrylamide polymers are crosslinked using a trivalent metal ion which is usually Chromium (III) (Sydansk and Smith, 1988). Chromium (III)-Carboxylate/Acrylamide-Polymer (CC/AP) gels are characterized by having robust gel chemistry in water with a wide range of water salinities, being highly insensitive to reservoir interferences. They are also resistance to CO_2 and H_2S, easy to implement in field, and cost competiveness (Southwell, 1999). CC/AP gels are applicable over a broad reservoir temperature range; however, extensive laboratory and field cases confirmed that they should be used in a formation temperature of less than 220°F (Sydansk and Southwell, 2000). For high temperature applications, medium molecular weight polyacrylamide polymers are crosslinked with an organic agent and a stabilizer to delay the gelation process. In this study, these gels are depicted as organically-crosslinked-polyacrylamides bulk gels (OCAP-BGs). An example of this specialized chemistry is the UNOGEL technology developed by Union Oil Company of California (UNOCAL) which can be applied at temperature ranges of 200 to 300 °F (Norman et al. 2006).

Bulk gels are applied to treat strong drive-fluid channeling that typically occurs in naturally fractured reservoirs and extremely high permeability matrix-rock reservoirs (Smith and Larson, 1997). Bulk gels are designed to reduce water production by totally or partially blocking the high conductive zones by reducing their permeabilities. Typical injected volumes of these agents range from a few hundred to tens of thousands of barrels; therefore, offending zones that are small in volumes relative to the size of the reservoir are good candidates. From their state-of-the-art, bulk gels are only considered as plugging agents, or a conformance-control strategy that works solely by correcting the formation permeability heterogeneity.

Colloidal Dispersion Gels. Colloidal Dispersion Gels are in-situ microgels aggregates that are formed by crosslinking of low concentrations (150 to 1200 ppm) of high-molecular-weight (> 22 million Daltons) hydrolyzed-polyacrylamide polymer with aluminum citrate or chromic citrate to produce a weak gel. Such low polymer concentrations are not enough to form a continuous network, and thus, they produce a solution of separate gel bundles that are almost spherical particles with sizes in the range of nanometers of 50 to 150 nm (Castro et al. 2013). These gels can flow under differential pressures that are greater than their transition pressures, as was experimentally demonstrated by Mack and Smith (1994).

The application of CDGs is limited to injection wells and involves injection of large volumes that are comparable to those of polymer flooding and are expressed in terms of pore volumes as well. Sweep efficiency improvement is achieved by providing in-depth fluid diversion due to deep gel penetration and weak strength that result in complete or partial blocking of high-conductive zones. Mack and Smith (1997) mentioned that based on field results, CDGs work by flooding preferred water flow paths between injectors and producers once-through, they restrict the flow to preferential water paths and force it to tighter rocks. This conformance technology has been widely applied to heterogeneous matrix-rock sandstone reservoirs produced by waterflooding with adverse mobility ratios.

Many studies have recently displayed CDGs as a feasible technology fundamentally for mobility control with additional benefits of reducing the permeability of high conductive zones (Castro et al. 2013). They have also stated that this technology is an alternative or a modified version of the polymer flooding like some other studies (Manrique and Lantz, 2011). Others have given equal importance to both functions of these agents as in-depth conformance improvement and mobility control strategy (Manrique et al. 2014). However, both groups have referred to injection of CDGs as "floods" rather than "treatments" due to the large volumes injected in the field applications. Furthermore, they have stated and validated the possibility of displacement of viscous oil s by CDGs by comparing the oil responses of the first and second treatments of a retreated injection well. It is noteworthy that in this study, we have considered only CDG historic cases that involved the co-injection of the polymer and crosslinker where the early sequential gel applications were eliminated.

Weak Gels. Weak gels (WGs) are a subdivision of the bulk gel systems that have been terminologically separated to distinguish their objectives of application from those of the original technology, i.e., BGs. Essentially, these agents are low to intermediate polymer concentrations, weak strength bulk gels that can have the same or different mechanisms for improving sweep efficiency depending on how and where they are applied. In literature, several criteria have been used to characterize this gel system as illustrated by the following points:

1. In the bottle testing gel strength code system (A to J) proposed by Sydansk (1990), weak gels have Code B which refers to a highly flowing gel.
2. Han et al. (2014) have categorized a gel system as a weak gel if it has a storage modulus ($G^{'}$) less than 1 dyne/cm^2.
3. Wang et al. (2002) experimentally have showed that in order to form a weak gel, the storage modulus should be in the range of $0.1 < G^{'} < 10$ dyne/cm^2. The authors have also noted that the minimum polymer concentration required to form a weak gel is 2000 ppm, and the differences between storage modulus and the viscous modulus are relatively small.
4. Liu et al. (2010) reported that weak gels have polymer concentrations between 800-2000 ppm without further illustration about the resulted gel structure.
5. Some researchers have implied that any bulk gel system (regardless of its concentration) is a weak gel if it forms a flowing gel in the reservoir conditions under certain ranges of pressure gradients. Sheng (2011) mentioned that weak gels have a high resistance to flow but are still able to flow so can be injected deep into the reservoir. Han et al. (2014) provided similar ideas and referred to WGs and CDGs as flowing gel processes. Furthermore, Song et al. (2002) and Lu et al. (2010) pointed out that WGs are oil-displacement agents in addition to their function as blocking agents.

In this study, all reviewed weak gels history cases are from China where this conformance system has been extensively applied in heavy oil, unconsolidated sandstone reservoirs as an in-depth fluid diversion technology. However, only SPE history cases were included in this study due to translation issues and to avoid any bias to this conformance technology. It is important to mention that both metallic and organic crosslinking agents were used to form weak gels in these cases; however, organic crosslinkers were not used for the purposes of high temperature applications as reservoirs temperatures in most of these cases are from 109 to 163°F.

Polymer Gels Data: Features, Problems, and Analysis

We have constructed a specialized database using the data of gel field projects published in SPE papers and U.S. DOE reports from 1978 to 2015. Other sources have been reviewed for the purposes of following and updating some history cases. During this stage, concentrated attention was paid to obtain a representative sample for the population of field applications and to avoid any biases toward particular regions or treating agents. At the present time, the data set includes 111 field trials for the considered technologies with over 50 parameters that include main reservoir and fluids properties, operating parameters, and performance parameters. It is important to note that for the reservoir and fluids characteristics, the reported values are the averages properties of the reviewed fields. Additionally, some parameters' estimates are time-specified, and the provided data are their values at the times of evaluations.

We think that each gel system and conformance problem type have "definitive" influences on the designs and responses of the gel treatments. In other words, they have certain "fingerprints" at different stages of the process and especially on the learned lessons. Averaging or summing the design and evaluation parameters for different reservoir conditions or blocking agents, which is the normal situation in the published history cases, tends to vanish these imprints as it resulted in mixed values for these parameters. Some examples of these mixed data are for carbonate and sandstone formations, bulk and microgels systems, and different oilfields. Therefore, the following definition for the project has been adopted in order to split a case history into two or more projects that illustrate the real behavior or performance of different agents utilized to remedy different conformance problems. A project is any number of jobs that were performed in or with a different field, reservoir, lithology, plugging agent, and problem type in an injector, and this injector continued to be used for the injection process after the remediation with polymer gels.

Gel treatment is a pattern-based process in all its aspects and stages which means that it has two different frequencies for the projects and treatments as shown in Table 1. This data type, (i.e., dual-frequency) greatly helps in assuring the clarity of successful application circumstances. For a given conformance agent, we think that the projects number reflect the variation in application conditions, while the number of treatments indicate the success of a project in comparison to another project. Normally, projects that show positive results at early stages will continue longer with a larger number of treatments when compared to projects that start with unsuccessful jobs. Since validity limits of screening criteria are based on successful projects, considering treatment frequencies gives current guidelines an additional feature in assuring the accuracy of the established application conditions as will be illustrated later in this paper. Sometimes these observations presented by mentioning the number of the treatments per project (TPP). Parameters’ intervals that have large numbers for both frequencies are considered preferable for conformance improvement treatment and have been referred to as the most applied ranges (MAR).

Table 1. Statistics of Projects and Treatments in Injection-Well Gel Field Projects Survey (1978-2015)

Gel Technology	No. of Projects	No. of Treatments	Treatment per Project (TPP)
Bulk Gels	57	607	10.6
Microgels (CDGs)	44	80	2
Weak Gels	10	110	11
Total	**111**	**797**	**7.2**

For reservoir and fluids properties, missing data were evaluated progressively using three different approaches. First, the relevant information of the reservoir or well pattern of interest has been extracted from other SPE papers that deal with application of other IOR processes for that field. Other sources also utilized for data filling purposes like National Petroleum Council Public Database (1995), Wyoming Oil Reservoir EOR Database (2010), Oil and Gas Journal Data Book (2006), and Oil and Gas Journal EOR Surveys (2008). Secondly, we have examined some imputation methods such as multivariate imputation by chained equations (MICE) package in R software (Van Buuren and Groothius, 2009) to estimate the missing values. However, these methods produced imputed values that are always within ranges of the observed data and have the same gaps as shown by Figure 2 for the DPc data set. This implies that screening limits will remain unchanged; however, imputation will increase the frequencies in certain ranges of property values, the matter that would falsify the most applied ranges (MAR) interval for that property. Thus, these completed data sets have been saved for further analyses, but not for screening purposes.

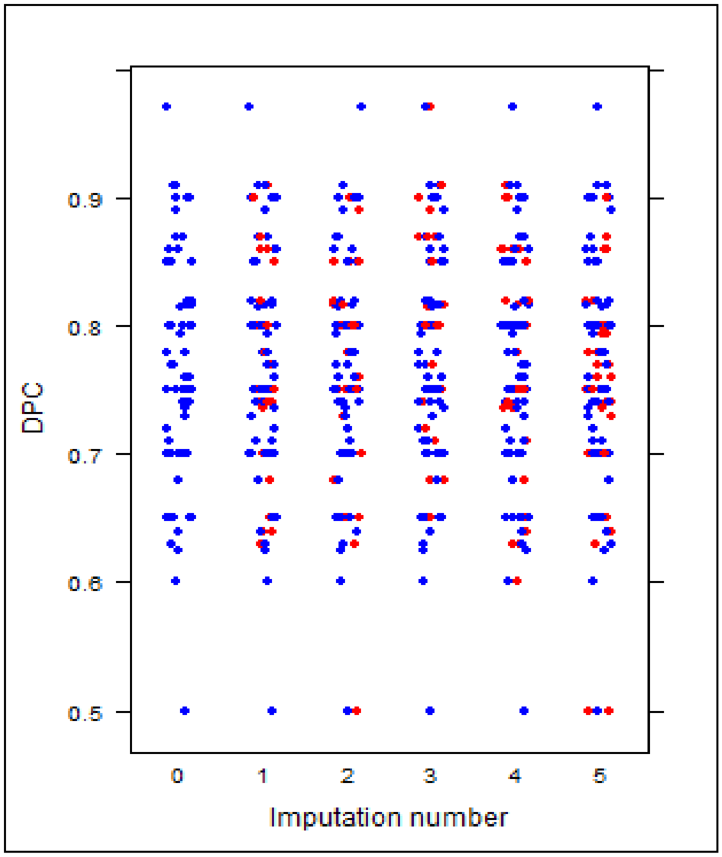

Figure 2. Original Dykstra-Parsons coefficient (blue) and five imputed (red) data sets using MICE package in R

Finally, we tested the possibility of using correlation methods to predict the missing values. For some properties, good association powers were obtained such as permeability vs. porosity (Figure 3), viscosity vs. API gravity, and mobility vs. viscosity. However, for properties that really have low number of data points such as DPc and water salinity, we did not obtain good association trends. Again, the predicted values did not change screening limits for almost all desired properties; therefore, the original data set remained unchanged to emphasize that SPE papers are a good data source.

To ensure data quality, outliers have been detected using the scatterplots as shown in Figure 3, the interquartile range method (IQR), and the three standard deviation rules

(Figure 4). Scatterplots with the help of the human eye define a data point as an outlier if it separates far away from a cloud of the points for a particular data set. The interquartile range and standard deviation consider a point as an outlier if it lies outside the calculated upper and lower limits explained by Figure 4.

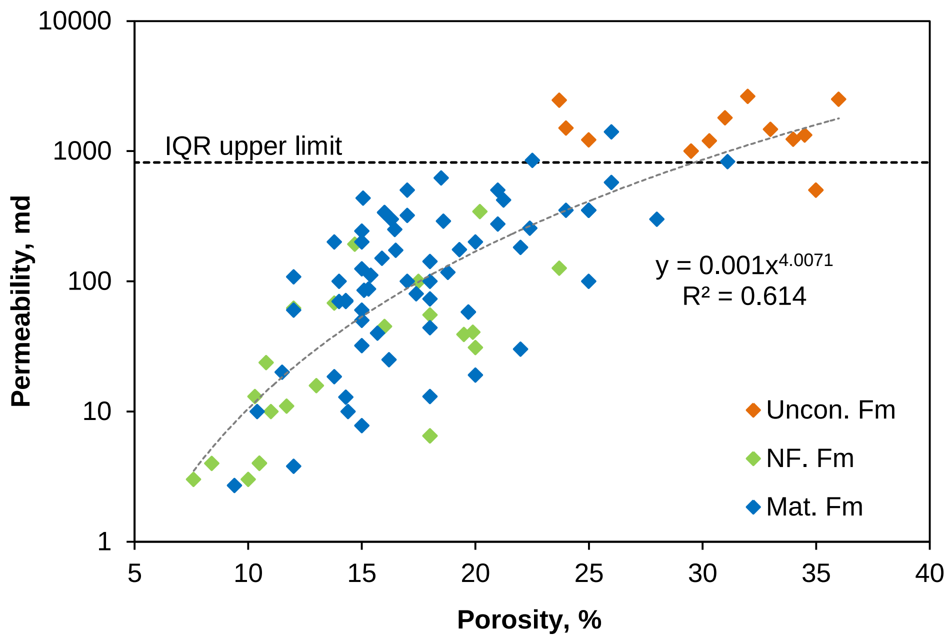

Figure 3. Porosity and permeability crossplot for different formation types

The IQR method indicated that most data sets have potential outlier points, as shown by Table 2. In this study, data sets were collected through careful review of each individual history case for a long period of time, and usually using more than one information source and reference. This allowed the authors to check the data at least two times, the matter that built a personal confidence that the summarized data have high quality. For the above reasons, reservoir engineering viewpoints have been adopted in parallel with statistician standpoints to judge possible outlier points as illustrated by the following example.

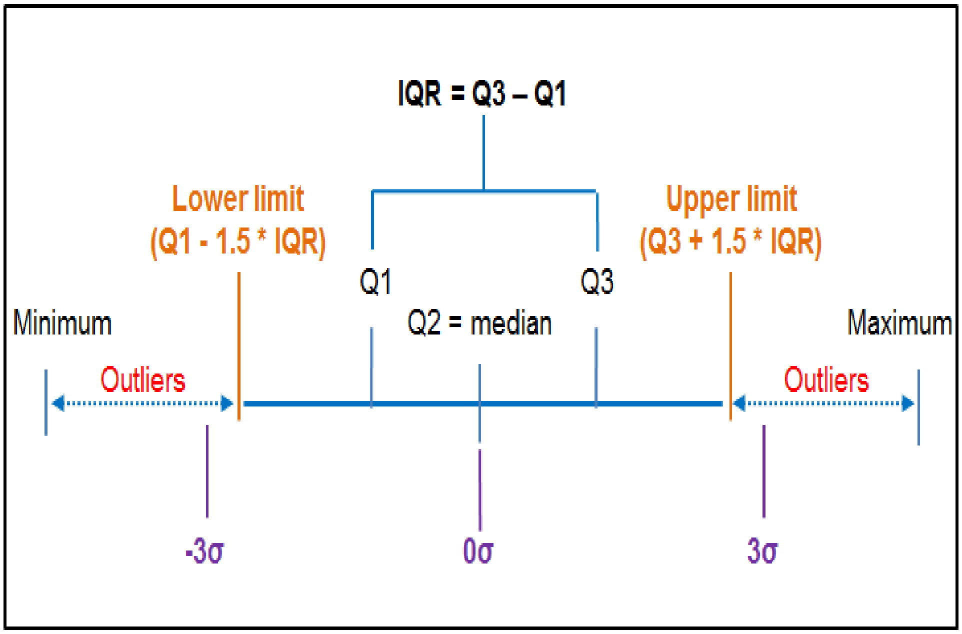

Figure 4. Illustration of three standard deviations rule and interquartile range method

According to the IQR method, 15 points above the upper limit line were identified as potential outliers in the permeability data set as shown by Figure 3. After processing the data per formation type, we found that 13 points are of unconsolidated sandstones, which normally have higher permeability values than other formation types. Due to the low number of data points for this formation type (14), the IQR interval was not wide enough to include these data points. If there was enough data for unconsolidated reservoirs, then it may have formed cloud of points around current points and extended the IQR upper limit so they would have not been outliers anymore. We can easily see that these points are on the general association trend, and their corresponding porosities are within reservoir engineering considerations (< 48%). Several such examples were recognized for the effects of the formation type, ongoing IOR process (steam injection), and the applied agent in addition to the drawbacks of the detecting methods themselves. Consequently, no data points were ruled out in this study.

Table 2. Descriptive Statistic Summary of Screening Parameters for Polymer Gel Projects

Parameter	ϕ	k	DPC	T	h	D
Units	%	md	fraction	°F	ft	ft
Points Count	111	106	77	111	98	111
Missing Points	0	5	34	0	13	0
Mean	18.7	338.3	0.77	153.6	87.3	5891
Median	17.5	109.5	0.77	145.4	37.4	5628
St. Dev	6	539	0.09	48	120	2582
CV	0.35	1.59	0.11	0.31	1.38	0.44
Minimum	7.6	2.7	0.50	72	5	300
Maximum	36	2634	0.97	350.3	670	12500
1st quartile	15	34	0.71	122	23	4010
3rd quartile	22	341	0.82	177	80	7875
IQR	7	307	0.11	55	57	3866
Lower Limit	3	-427	0.55	40	-63	-1789
Upper Limit	33	802	0.99	258	166	13673
# of Outliers	5	15	1	5	16	0
MAR	10-20	10-500	0.6-0.9	100-200	10-40	3000-9000

Table 2. Descriptive Statistic Summary of Screening Parameters for Polymer Gel Projects (Cont'd)

Parameter	µ	API	Salinity	Mobility	WC	RF
Units	cp	degree	ppm	ratio	%	%
Points Count	101	104	61	32	78	76
Missing Points	10	7	50	39	33	35
Mean	92.8	27.2	37206	8.6	62.2	19.4
Median	11.0	25	15781	4.7	83.3	15.7
St. Dev	488	8	43965	14	39	12
CV	5.26	0.28	1.18	1.66	0.63	0.64
Minimum	0.3	11.5	150.0	0.6	0	1.6
Maximum	4800	42.5	173207	80	100	49.4
1st quartile	4	21	5496	2	12	9
3rd quartile	28	34	67382	9	95	25
IQR	24	13	61886	8	83	16
Lower Limit	-33	1	-87333	-10	-112	-16
Upper Limit	65	54	160211	21	219	49
# of Outliers	16	0	2	2	0	0
MAR	0.1-100	20-35	-	1-10	60-100	1-10

Initially, each parameter data set has been holistically analyzed (regardless of the treating agent) using descriptive statistics to show the central and dispersion tendencies of the data. Fifteen different statistical parameters have been evaluated for the objectives mentioned above as shown in Table 2. In this study, the coefficient of variation (CV) has been utilized to show data heterogeneity along with the standard deviation since the latter is highly affected by units of the analyzed parameter. Secondly, frequency distributions have been presented using stacked histograms, which summarize the number of projects or treatments according to a particular aspect or property range as shown in Figure 5 through 18. It is important to note that all above analyses contain all data set points regardless of the technical and economic feasibility of the projects whether they were successful or not. Finally, based on successful field trials, technical screening criteria limits were extracted for each gel system and presented using eight statistical parameters to describe the validity limits of each reservoir or fluids property. It is important to note that the project and treatment percent presented in the next sections are based on the available data for each property not the total numbers (111and 797).

Evaluation of Polymer Gels Applicability Guidelines

Screening criteria offer a way to test the appropriateness of the proposed IOR/EOR recovery process for a given field. They check the compatibility of injected fluids with the reservoir rocks and fluids properties, permeability, depth, temperature, oil viscosity, and oil saturation are usually included in the analyses. For EOR processes that target the microscopic displacement efficiency, the above parameters are sufficient to build an initial screening system simply because the limiting factor or the problem is the rocks and/or fluids properties themselves. These properties are extensively measured or estimated during different stages of the field life, and thus, they have good representative values to be used in the screening analyses.

As a matter of fact, reservoir conformance problems have various roots and forms that can occur everywhere in the reservoir. Linking the problem to an effective solution requires taking into consideration all relevant factors that may affect the solution type, design, and performance. This implies that, in addition to the parameters that have been considered for other EOR technologies, evaluations of polymer gels applicability should incorporate all parameters that depict conformance issues roots and characteristics. In this context, Shevelev et al. (2012) have pointed out that the applicability of polymer gels, polymer flooding, and colloidal dispersion gels depends on the problem, i.e., water channeling and adverse mobility, and their compatibility with given reservoir conditions like temperature, salinity, and lithology.

However, characteristics of the reservoir conformance problems are difficult to be assessed or measured in the field with precision, and several diagnostic techniques have been used to evaluate these characteristics along with traditional geological and reservoir characterizations. As a consequence, evaluation of these aspects has been historically performed qualitatively or subjectively using some related reservoir properties, operational and testing measurements, and engineering considerations of the conformance problems and gel technologies. Thus, for polymer gels, numeral screening studies are not able to consider all the influential characteristics of conformance problems due to the qualitative nature of their evaluations, which were obtained using various diagnostic techniques.

Based on the above considerations, we have identified that 13 quantitative parameters, 3 categorical variables, and 4 qualitative aspects of conformance problems are required to develop an integrated selection system for conformance technologies as shown in Table 3. In this paper, only screening parameters (quantitative and categorical) are presented Table 6 due to the limited space. The formation type (along with lithology), ongoing IOR/EOR process, permeability variation, mobility ratio, water cut, and recovery factor were included in the applicability guidelines for the purpose of developing comprehensive guidelines. In the next sections, we will briefly discuss important observations about some parameters and comparisons with previous screening studies. Furthermore, to facilitate utilization of the developed guidelines, Excel spreadsheets were constructed that can be downloaded from the author's Researchgate account with title of "Polymer Gels Quick Screening Tool".

Table 3. Summary of Screening and Matching Parameters Required for Selection of Polymer Gel Technologies

Quantitative Parameters	Qualitative Parameters
1- Reservoir properties: - Reservoir Lithology - Formation type - Porosity - Formation permeability - Permeability variation - Temperature - Thickness - Depth	1- Drive-fluid channeling: - Channeling strength - Channeling pattern 2- Offending zone - Volume of channel - Oil saturation 3- Conformance problem status
2- Fluids properties: - API oil gravity - Oil viscosity - Mobility ratio - Water salinity - Oil saturation	- Undeveloped - Developed 4- Existence of cross-flow
3- Operational aspects: - IOR process - Water cut - Recovery factor	

Reservoir Lithology and Formation Type. Figure 5 shows distributions of the project and treatment frequencies according reservoir lithology and formation type aspects. This figure illustrates the following valuable points:

1- Only bulk gels are applied to carbonate reservoirs, whether they are matrix-rock formations or naturally fractured reservoirs.

2- Bulk gels were applied to all types of reservoirs and formations, more in sandstones (40) than carbonates (17), and more in matrix-rock formations (29) than in fractured reservoirs (20), and unconsolidated sandstones (8).

3- CDGs have been applied only in sandstone reservoirs, mainly in matrix-rock formations, a few times in fractured reservoirs (micro-fractures), but not in unconsolidated sandstones.

4- Weak gels have been applied only in sandstone reservoirs, mainly in unconsolidated and matrix-rock formations, and not in fractured sandstones.

5- It is clear that CDGs and WGs exhibit fair preferences toward matrix-rock and unconsolidated sandstones, respectively.

6- Although projects statistics show that BGs have been applied less frequently in naturally fractured reservoirs than matrix-rock reservoirs, treatment frequencies show that BGs have a comparable number of jobs for naturally fractured reservoirs (276) and matrix-rock formations (273). Furthermore, BGs projects have higher TPP in naturally fractured reservoirs (14) than in matrix-rock formations (9). Extracting the right inference is of extreme importance in such situations.

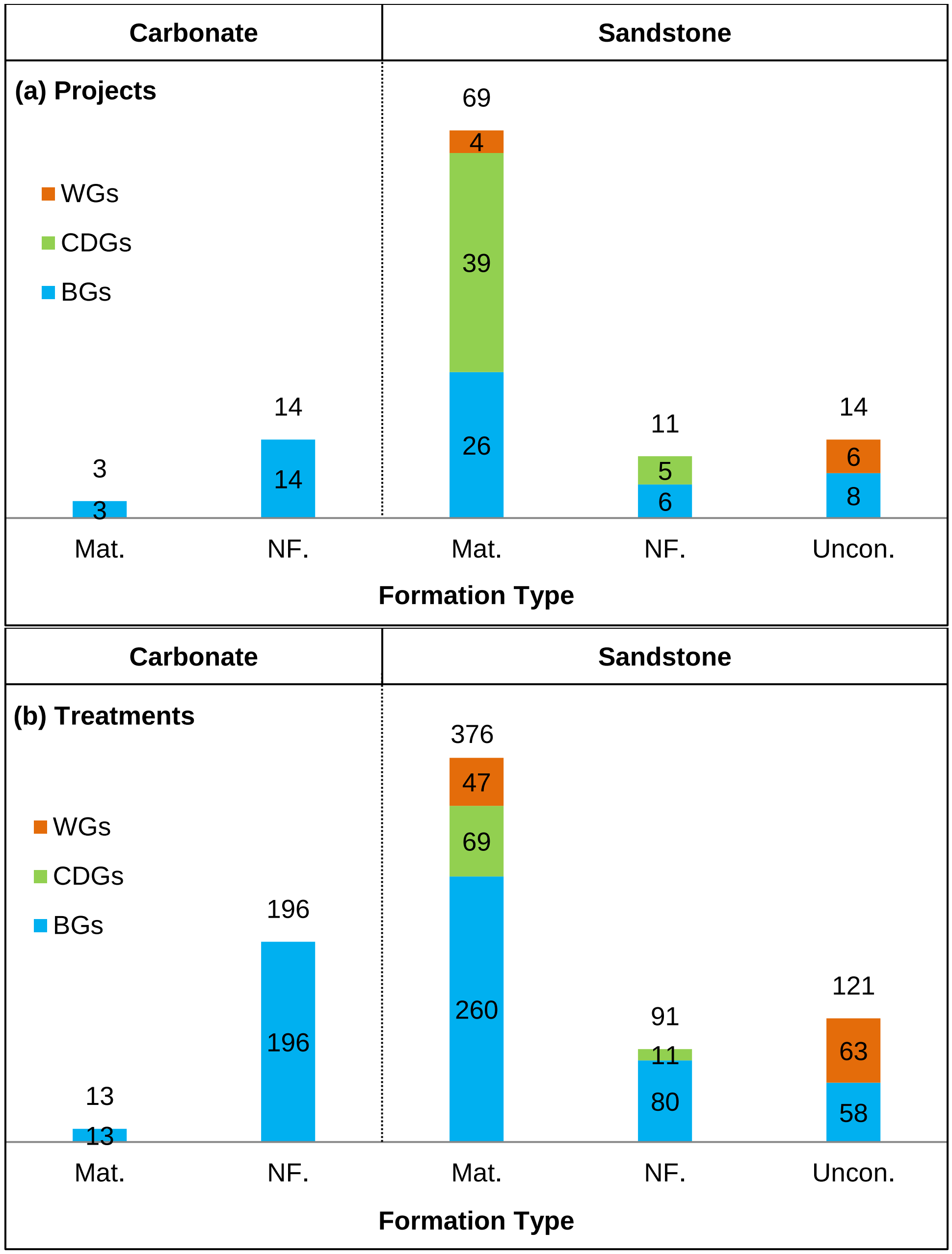

Figure 5. Distributions of (a) polymer gel projects and (b) treatments per reservoir lithology and formation type

IOR/EOR Recovery Process. For different gel technologies, Figure 6 compares the gel projects and treatments distributions according to the IOR/EOR recovery process, which illustrates the following points:

1- Polymer gels treated the channeling of only four IOR/EOR drive-fluids and more frequently of injection water in oilfield produced by waterflooding.

2- BGs have been utilized in fields that experienced all four IOR/EOR methods, and only OCAP-BGs have been used in fields recovered by steam injection. Also, for CO_2 floodings, only BGs have been applied.

3- Both CDGs and WGs have been applied only in reservoirs being exploited either by waterflooding or polymer flooding.

4- Again, while projects allocations in Figure 6-a show that BGs have exhibited more preferences towards waterfloodings than carbon dioxide floodings, the treatment frequencies shown in Figure 6-b illustrate that a higher number of jobs were performed in a gel project that carried out in carbon dioxide flooding than in waterflooding where the TPPs are 17.5 and 10, respectively. This is a good example of how the treatment statistics can correct false first impressions based soon project distributions.

Average Reservoir Permeability. Because of data availability, the average matrix rock permeabilities have been reported for all history cases; however, for dual porosity reservoirs, the target of the gel treatments is the natural fractures not the matrix block of the rocks. Therefore, the reported values are not representative in these cases. Also, Table 4 verifies that the lithology and formation types have significant effects in determining average permeability values. Furthermore, Figure 3 shows that the porosity and permeability applicability intervals are significantly affected by the formation type, especially for BGs and WGs where their intervals are greatly influenced by permeability values of naturally fractured and unconsolidated formations. As a result, we have identified that utilizing different permeability data types (mixed) simultaneously would

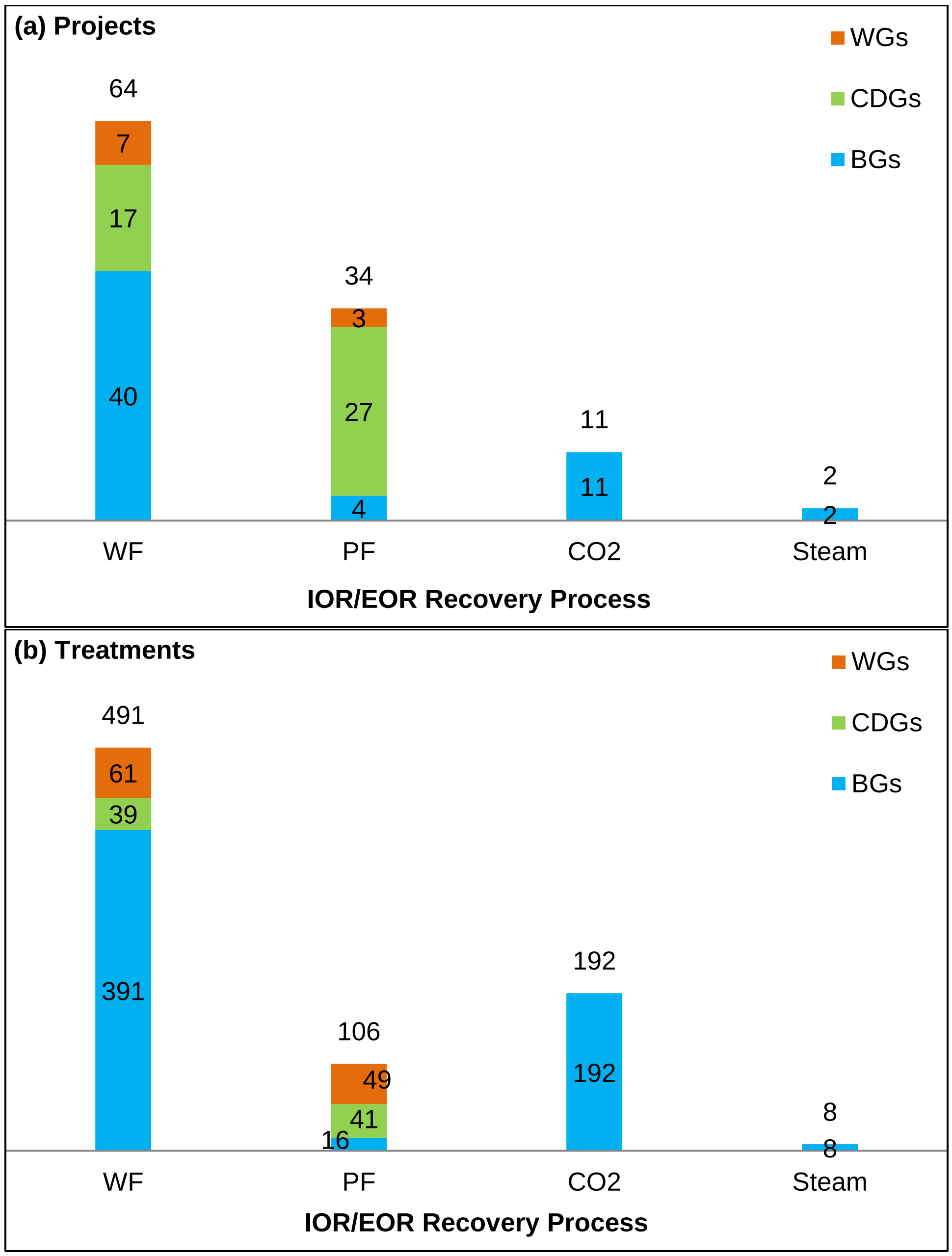

Figure 6. Distributions of (a) polymer gel projects and (b) treatments according to IOR/EOR process

falsify the conditions where polymer gels were really applied and it is necessary to analyze permeability data according to lithology and formation types. Figure 7 and Figure 8 compare distributions of gel projects and treatment according to reservoir matrix-rock porosity and permeability.

Table 4. Ranges of Average Permeability for Different Lithologies and Formation Types in Gel Projects Database

Reservoir Lithology	Formation Type	Permeability, md	
		Minimum	Maximum
Carbonate	Naturally Fractured	3	62
	Matrix-Rock	2.7	100
Sandstone	Naturally Fractured	10	342
	Matrix-Rock	3.8	1407
	Unconsolidated	500	2634

To illustrate the above observation, Table 6 and Figure 9-a compare the composite-established-permeability criteria for gel technologies where data of all the reservoir lithologies and formation types were analyzed together. This figure implies that MCAP-BGs were applied in matrix-rock sandstone reservoir with an average permeability of 1000 md. Actually, this is not correct because for this particular combination of chemical system and reservoir formation, the maximum applied permeability is 500 md based on the reviewed projects. However, permeability ranges are affected by the high permeability values of unconsolidated sandstone formations which mean that this property has a mixed data set. Thus, as mentioned earlier, reservoir lithology and formation type should be considered when applicability conditions are evaluated as shown by Figure 9-b and Table 5.

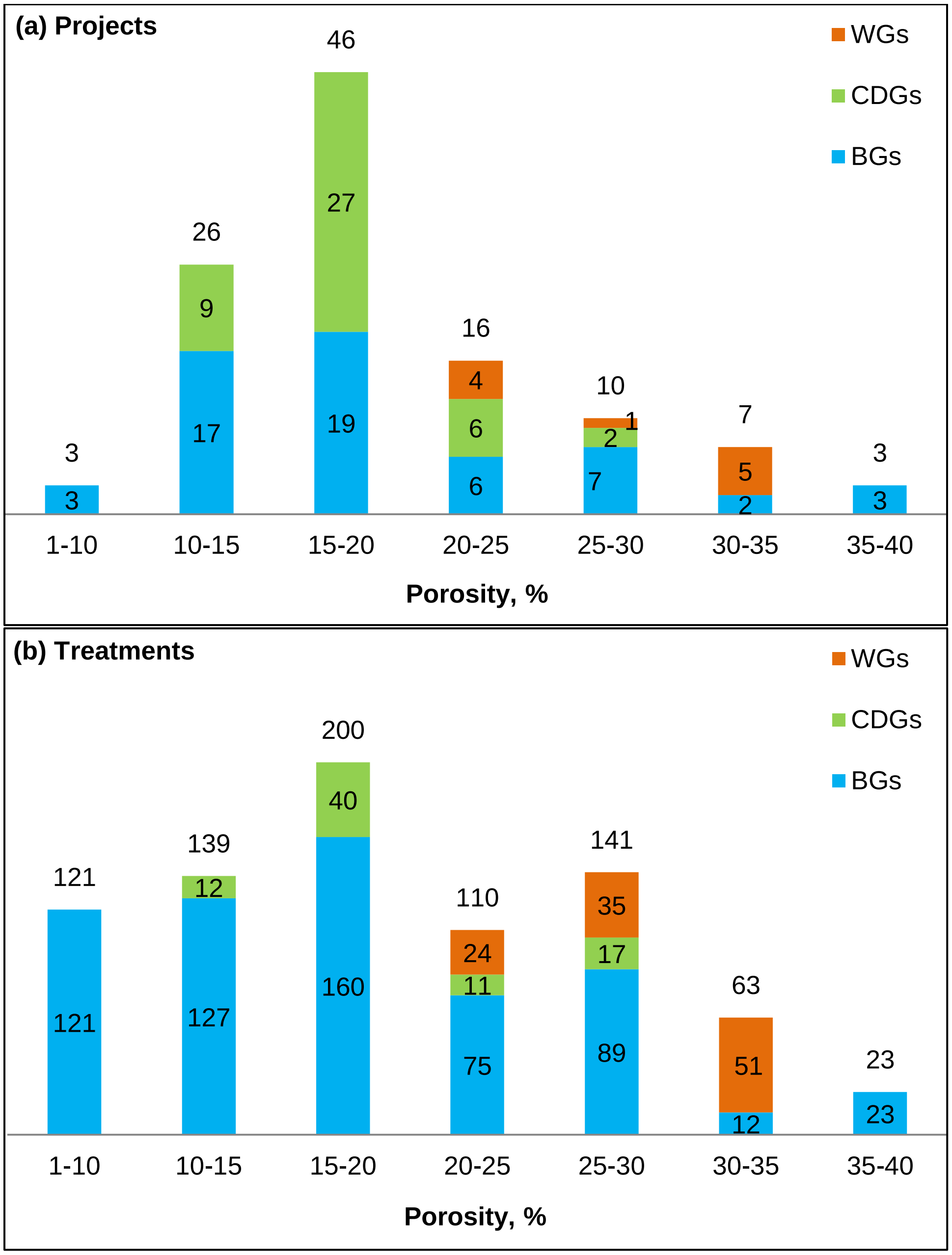

Figure 7. Porosity distributions for (a) polymer gel projects and (b) treatments

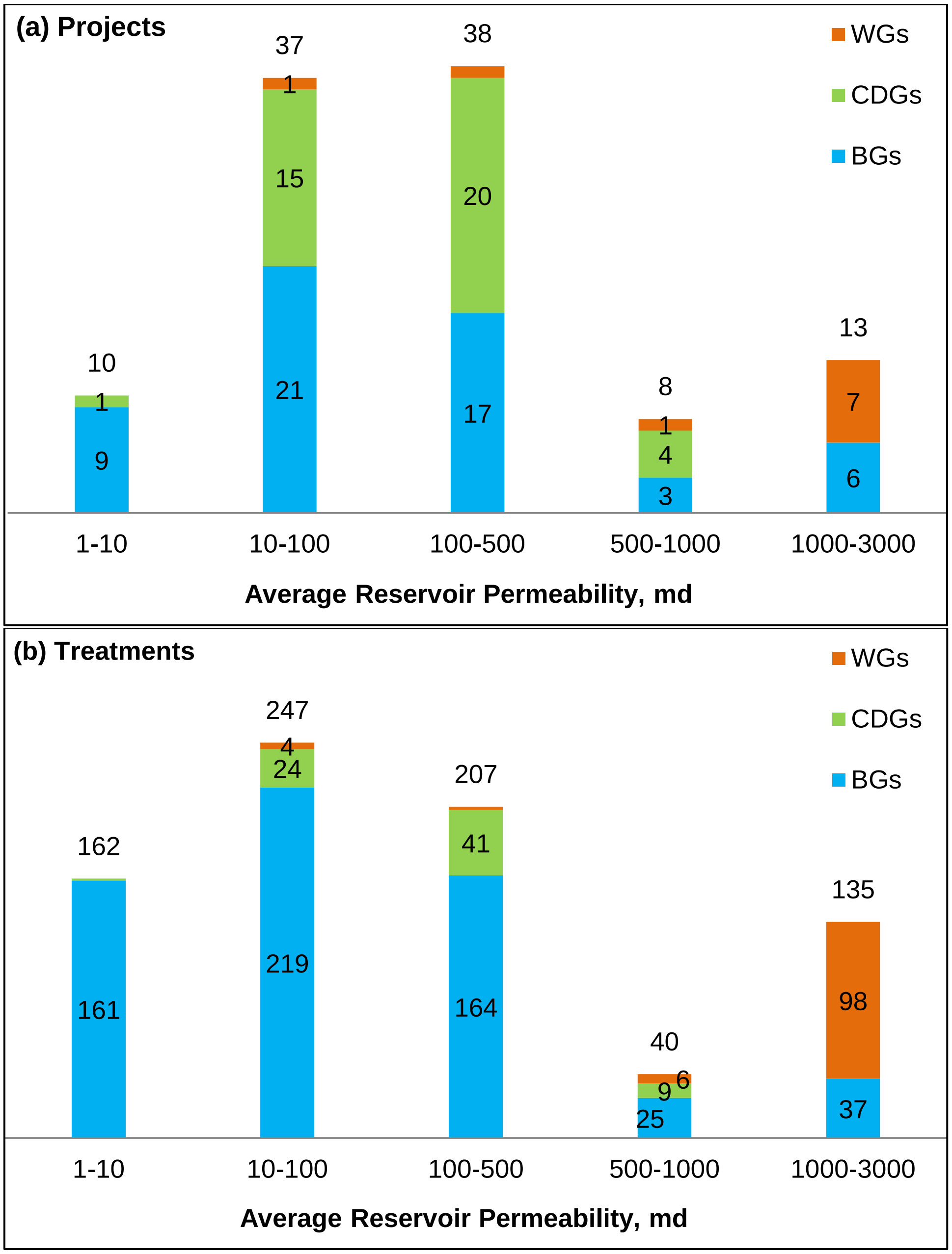

Figure 8. Average permeability distributions for (a) polymer gel projects and (b) treatments

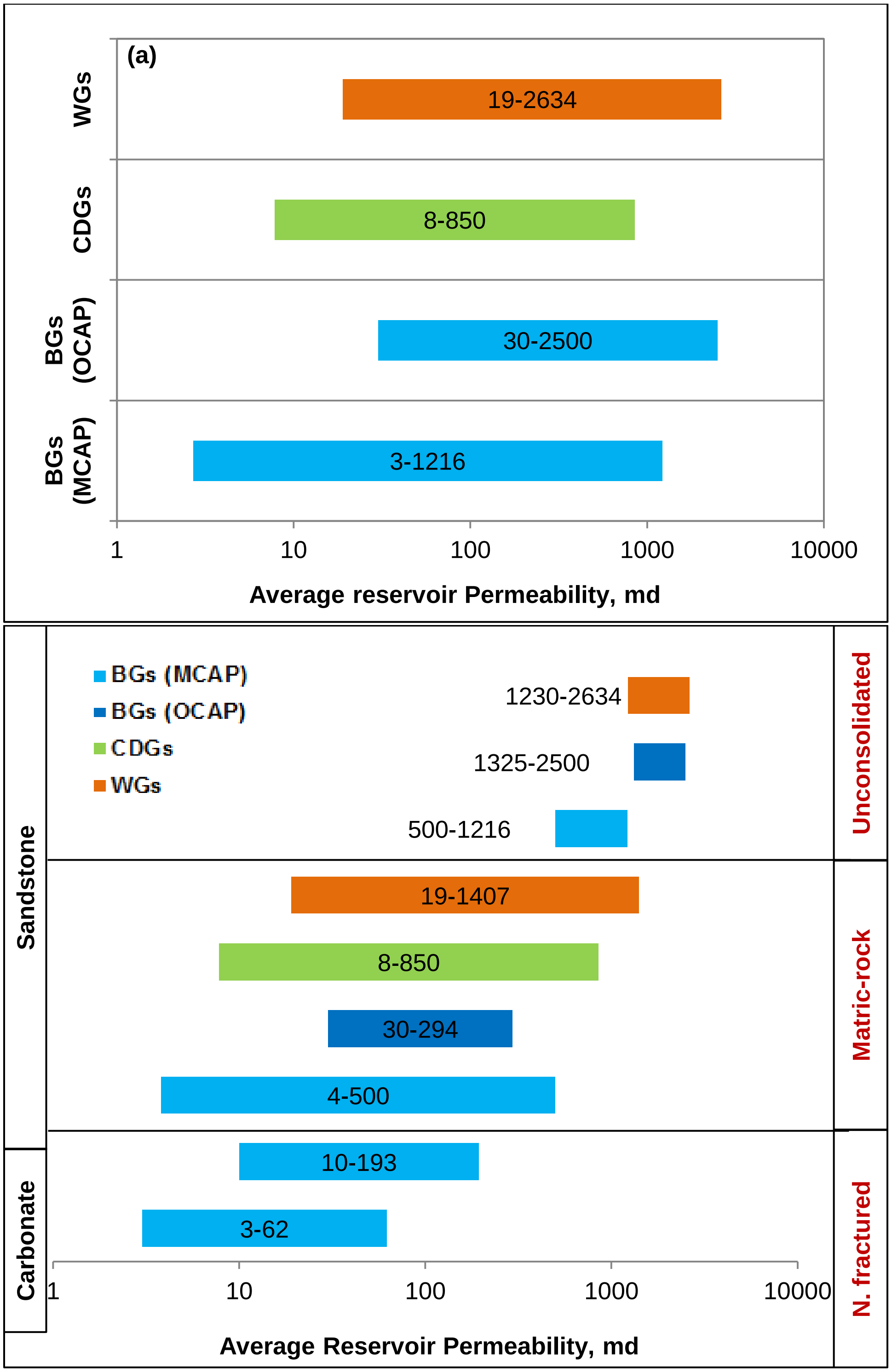

Figure 9. Comparison of permeability applicability ranges for polymer gels: (a) composite systems and (b) according to reservoir lithology and formation type

Table 5. Application Permeability Ranges of Polymer Gels Analyzed According to Reservoir Lithology and Formation Type

Lithology	Technology	Formation	Average Permeability, md	
			Min	Max
Carbonate	BGs	Matrix-rock	2.7	100
		Nat. Fractured	3	62
Sandstone	BGs	Matrix-rock	3.8	500
		Nat. Fractured	10	193
		Unconsolidated	500	2500
	CDGs	Matrix-rock	7.8	850
		Nat. Fractured	23.7	342
	WGs	Matrix-rock	19	1407
		Unconsolidated	1230	2634

* For naturally fractured reservoirs, matrix block permeabilities are provided

Permeability is probably the screening parameter that has been most affected by experts' opinions. Table 6 shows that BGs and CDGs have minimum averages of 3 md and 7.8 md; however, previous EOR screening studies indicated a minimum permeability value of 10 md or 50 md (Mack, 1978; Seright and Liang, 1994; Williams and Pitts, 1997) because some laboratory studies indicate that high-molecular-weight polymers do not propagate very readily in less than 10 md permeability rocks to avoid the internal pore-plugging (Zaitoun and Kohler, 1987; Seright et al. 2011). It is important to note that the average reservoir permeability is a summary representative value that has been evaluated using many different values over wide extensions (vertical and areal). Therefore, the gelant had not necessarily been injected into permeabilities equal to the average values and of course, it was injected into higher permeabilities of the highest flow capacity zones. Consequently, these values were not replaced in the applicability criteria as in the previous studies. Seright and Liang (1994) mentioned in their DOE report that 18% of the polymer floodings were applied in less than 10 md average permeability reservoirs.

Permeability Variation. In this study, the permeability variation has been considered in the terms of the Dykstra-Parsons coefficient, which it is the first time in EOR screening that this property has been evaluated in details rather than in the form of an expert opinion such as DPc >0.6. However, this property suffers from lack of data which is clear based on the number of missing data points (34). Interestingly, Figure 10 shows that gel field trials are distributed over only the upper half of the DPc values range (0.5-1.0), which implies that the permeability heterogeneity was the main cause for selecting polymer gels to improve sweep efficiency, even for systems that address the other root of drive-fluid channeling, (i.e., the mobility ratio). It is noteworthy that no effects have been indicated for the reservoir lithology or formation type on the data of this property.

The ICP (Instituto Colombiano del Petroleo) developed a methodology to select the possible solutions for improving sweep efficiency in Columbian oilfields that presented by Castro et al. (2013) and Maya et al. (2014). In this methodology, DPc has been introduced as a key parameter to guide the selection process where it suggests application of CDGs if $0.55 < DPc < 0.7$ and application of BGs for reservoirs with DPc values > 0.7. Table 6 illustrates that DPc application intervals are intersected with each other over wide intervals. This matter verifies that the selection of the appropriate treating agent should not be based solely on the permeability contrast as it stated in the aforementioned studies. The main problem with the previous statements is the existence

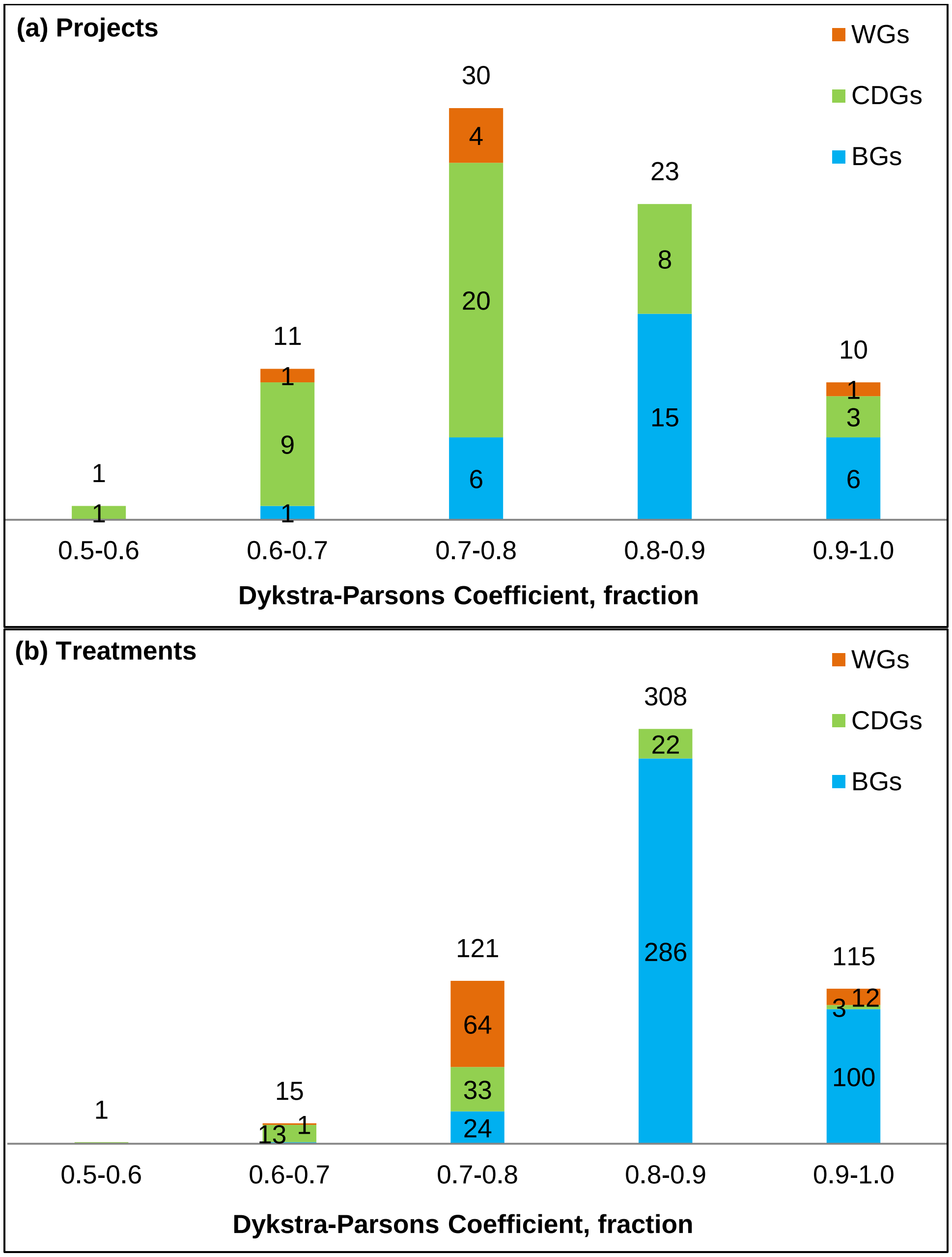

Figure 10. Permeability variation distributions for (a) polymer gel projects and (b) treatments

of a large number of CDG treatments in the range of 0.7 to 0.9 while these studies have preserved this extent for BG applications. This generally indicates that this methodology is a regional decision making rule that cannot be extended for other oilfields. It is important to note that CDGs lower limit (0.5) belongs to the Big Mac field; Lantz and North (2014) mentioned that this value is underestimated because water breakthrough occurred in 24 months instead of 30 months as predicted by the SRAM program.

Reservoir Temperature. The temperature statistics presented in Table 2 show that gel systems have been applied over a wide temperature range of 72-350°F with a median of 145°F. BGs have been applied over the entire temperature range through the utilization of organic crosslinking agents. However, the project and treatment distributions shown in Figure 11 have higher frequencies in the temperature interval of 100-200°F where 78% of the projects and 83% of the treatments are within this interval. In comparison, high temperature applications consist of less than 7% of the total number of gel projects.

For MCAP polymer gels, 88% of their projects have been applied in reservoir temperatures lower than 200°F, and only nine BGs and CDGs were applied in temperatures greater than 200°F and up to 220°F. Three of these trials are unsuccessful treatments. These statistics may confirm a general concern reported by Seright and Liang (1994) that most polymers may not be sufficiently stable at high temperatures. However, in the case of unsuccessful remediation of Sooner Unit, the authors reported that in this high temperature reservoir (220°F), bulk gels provided a reduction in injection rate and an increment in injection pressure for the entire evaluation period of one year.

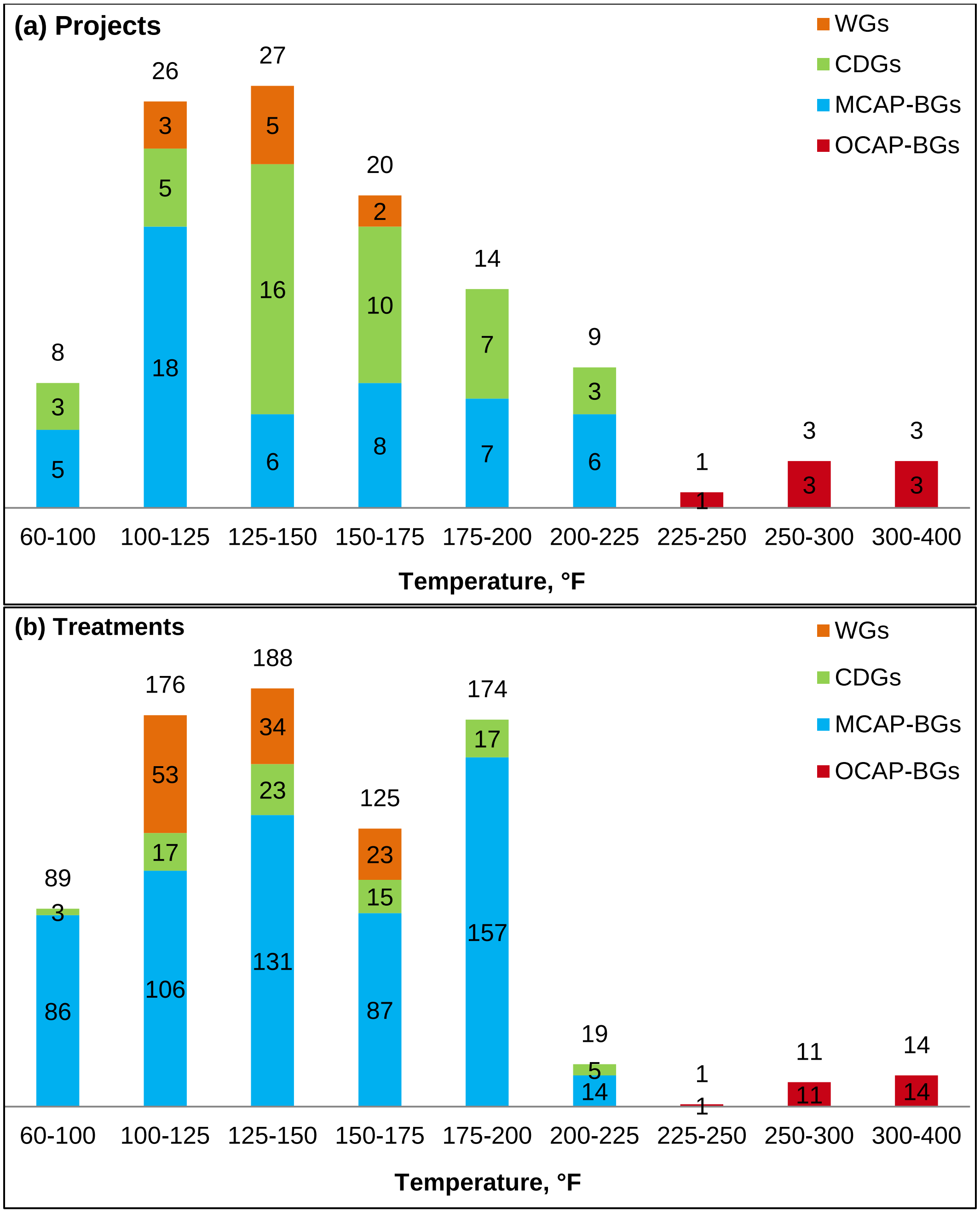

Figure 11. Reservoir temperature distributions for (a) polymer gel projects and (b) treatments

Based on the successful applications, temperature ranges of BGs and CDGs are fairly identical while WGs were applied in a narrower range that lies within BGs and

CDGs extents. This matching is attributed to the utilization of the same base polymer in these chemical systems, (i.e., polyacrylamides). On the other hand, employment of the organic crosslinkers has extended application temperature of the polyacrylamide-base bulk gels up to 350°F. It is extremely important to note that OCAP-BGs have a narrow temperature window of 275-350°F and all unsuccessful applications are in the range of 240-265°F. This indicates a distinct, wide gap in polymer gels application temperatures ranging from 210 to 275°F.

The discrepancies in the distributions of the gel projects and treatments in the temperature range of 200-225°F provide another example that further illustrates the self-checking feature of the developed guidelines. Out of 104 MCAP gels field implementations, 9 projects were implemented in this interval, the matter that reveals a high degree of applicability for the polymer gels in this region. However, considering that these nine projects involved only 19 jobs out of 771 treatments indicates that this temperature range is a critical region for polymer gels. Again, treatment frequencies corrected the seemingly obvious indicators from the project allocations.

Average Reservoir Depth. Polymer gels are injected at pressures below the formation parting pressures to avoid fracturing of the targeted formations. Parting pressure increases with the reservoir depth which means that maximum injection pressure also increases. On the other hand, injection time during a gel treatment is restricted by the gelation time; therefore, reservoir depth affects polymer gels injectivity and injected volumes for given gelation time, not only affects formation porosity and temperature. However, most previous screening and surveillance studies have not included this property in their evaluations of polymer gels. Again, gels projects have corresponding application ranges for the reservoir depth; moreover, for BGs, organic crosslinkers have enabled these agents to work in deeper formations where high temperatures are expected.

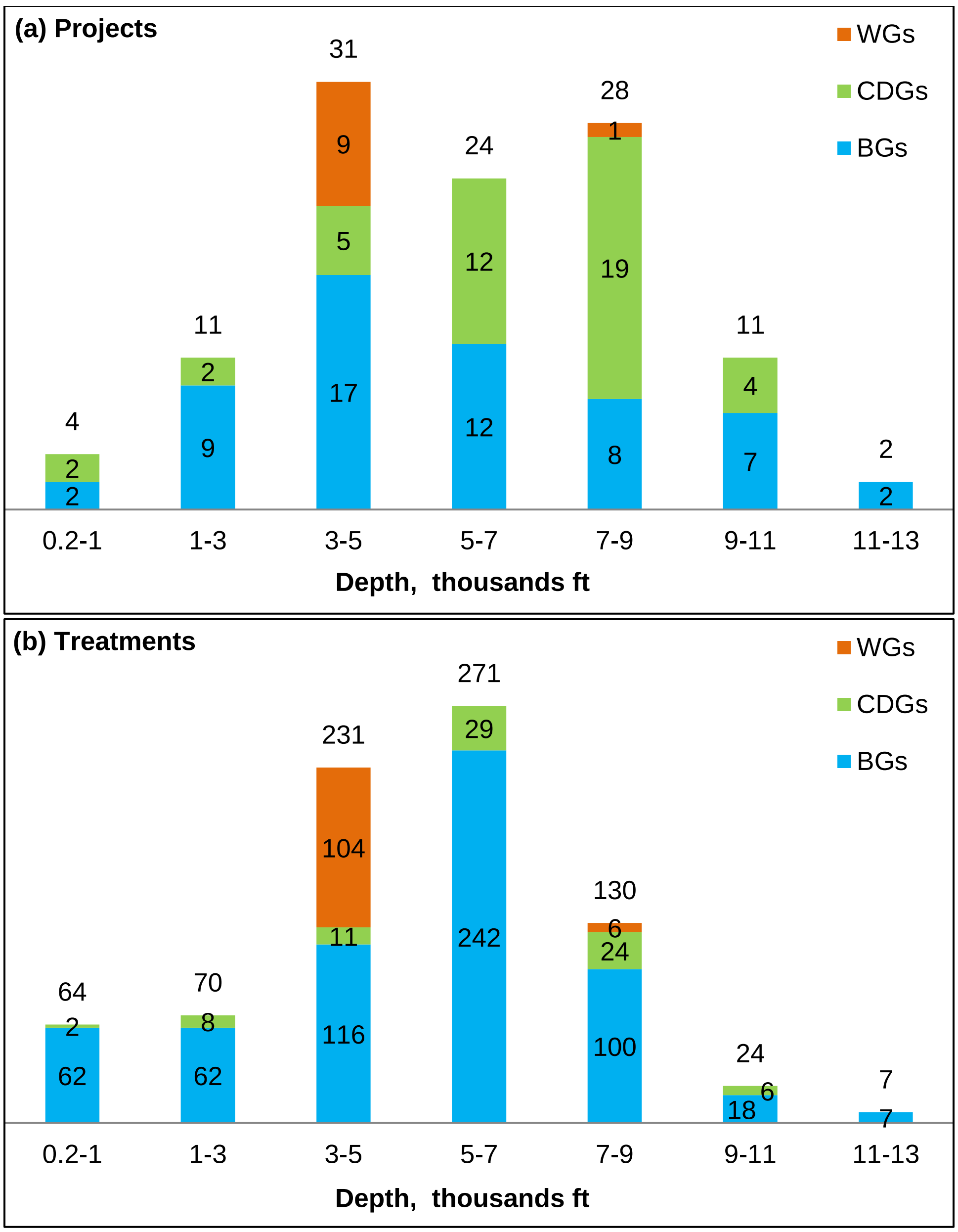

Figure 12. Reservoir depth distributions for (a) polymer gel projects and (b) treatments

Average Reservoir Thickness. Depending on the placement technology whether it is bullhead or mechanically isolated, conformance agents are introduced either into the entire reservoir net pay or only into particular zones that are a part of the reservoir thickness. The average net pay thickness data has been reported for all case histories, regardless of the placement method, because of data availability. For this property, project and treatment distributions (Figure 13) show a wide range of 5-670 ft with a median of 35 ft, and 56% of these trials are in a thickness interval of 10-50 ft. As for previous properties, BGs projects are extended over the entire net pay ranges while CDGs projects occupy the left side of the histogram where 92% of these frequencies are within 5 to 60 ft. This indicates that CDGs have generally been applied in thin formations despite their large injected volumes. Manrique et al. (2014) have showed that CDGs have been applied in average net pay ranges of 20-200 ft in their review; however; they recommended applying CDGs in thin reservoirs with net pay thicknesses less than 40 ft. For WGs, net pay ranges are more spread out than CDGs, yet they are still in thin formation ranges where 86% of them are within 20 to70 ft.

Oil Viscosity. For injection wells remedies, Williams and Pitts (1997) have considered oil viscosity as uninfluential in the performances of BGs. This is probably because these gels are injected into the oil-swept-zones where no oil displacement by the gelant is expected. Seright and Liang (1994) considered the oil-water viscosity ratio and assumed endpoint permeabilities to conclude that channeling was caused more by the reservoir heterogeneity than the mobility ratio. In contrast, CDGs and WGs evaluation studies have given a special prominence to oil viscosity because these flood-size treating technologies function as improved-permeability-reduction mobility control strategies (Castro et al. 2013; Manrique et al. 2014; Song et al. 2002; Lu et al. 2010).

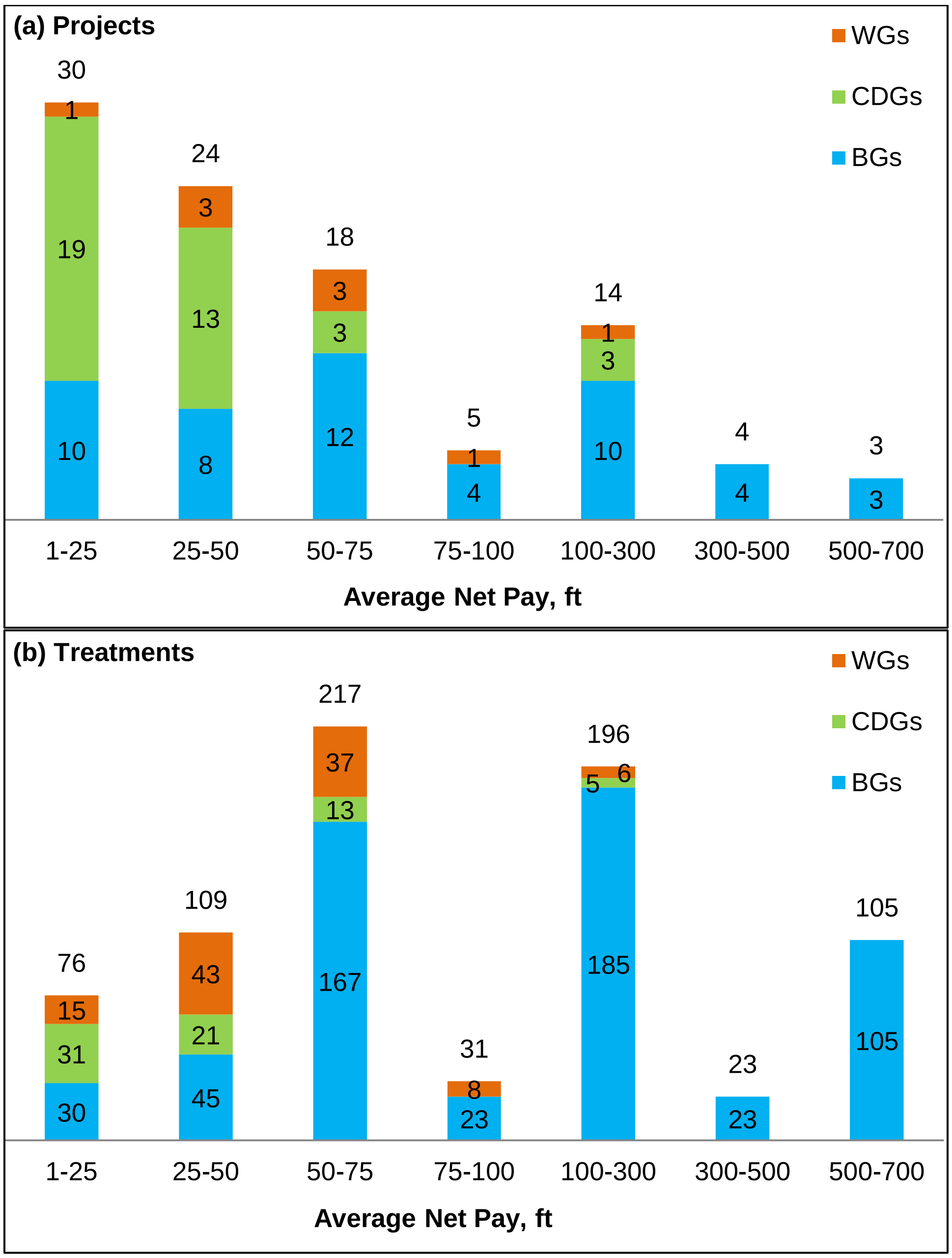

Figure 13. Reservoir net pay thickness distributions for (a) polymer gel projects and (b) treatments

In this study, oil viscosity has been considered for BGs as a screening parameter for the following possibilities: subsequent water injection will surely affect the placed gels in the high permeability zones (load pressure). In turn, it will be influenced by oil viscosity (fluid resistance) as it is injected into the oil saturated, low permeability zones. Therefore, it is possible that oil viscosity somehow has some effect on how subsequent water flooding interacts with gels in high permeability zones. We think that the effect of the load pressure on gel pack permeability is a function of oil viscosity in the unswept, low permeability zones.

Polymer gels projects have wide application ranges of 0.3-4800 cp with a median of 11 cp and have mainly been injected into light oil reservoirs where 83% of the projects and 81% of the treatment were in oil viscosity intervals of 0.3-50 cp. However, BGs have also been applied to heavy oil reservoirs where steam flooding and CO_2 flooding were implemented to address oil viscosities. In heavy oil regions (>100 cp), BGs were the dominant agents, then WGs with two projects, and no trials for CDGs where they were entirely applied to light oil reservoirs 1-40 cp with median 12 cp. It is important to note that viscosity limits are also affected by the formation type especially unconsolidated sandstones.

Mobility Ratio. Recall that bulk gels function only as permeability-reducing materials (plugging agents), and the other two systems function as in-depth fluid diversion technologies. This reveals that the mobility ratio is an important screening criterion for CDGs and WGs systems but not for BGs. However, bulk gels data were processed only for comparison purposes. In this study, the provided values by cases histories are the mobility ratios during waterflooding stages. The data set of this property (and water salinity (Figure 16) as well) has a low number of data points where only 72 history cases have provided this ratio as shown in Table 2. However, in 37 of these 72 field trials, mobility ratio was qualitatively described as favorable and unfavorable.

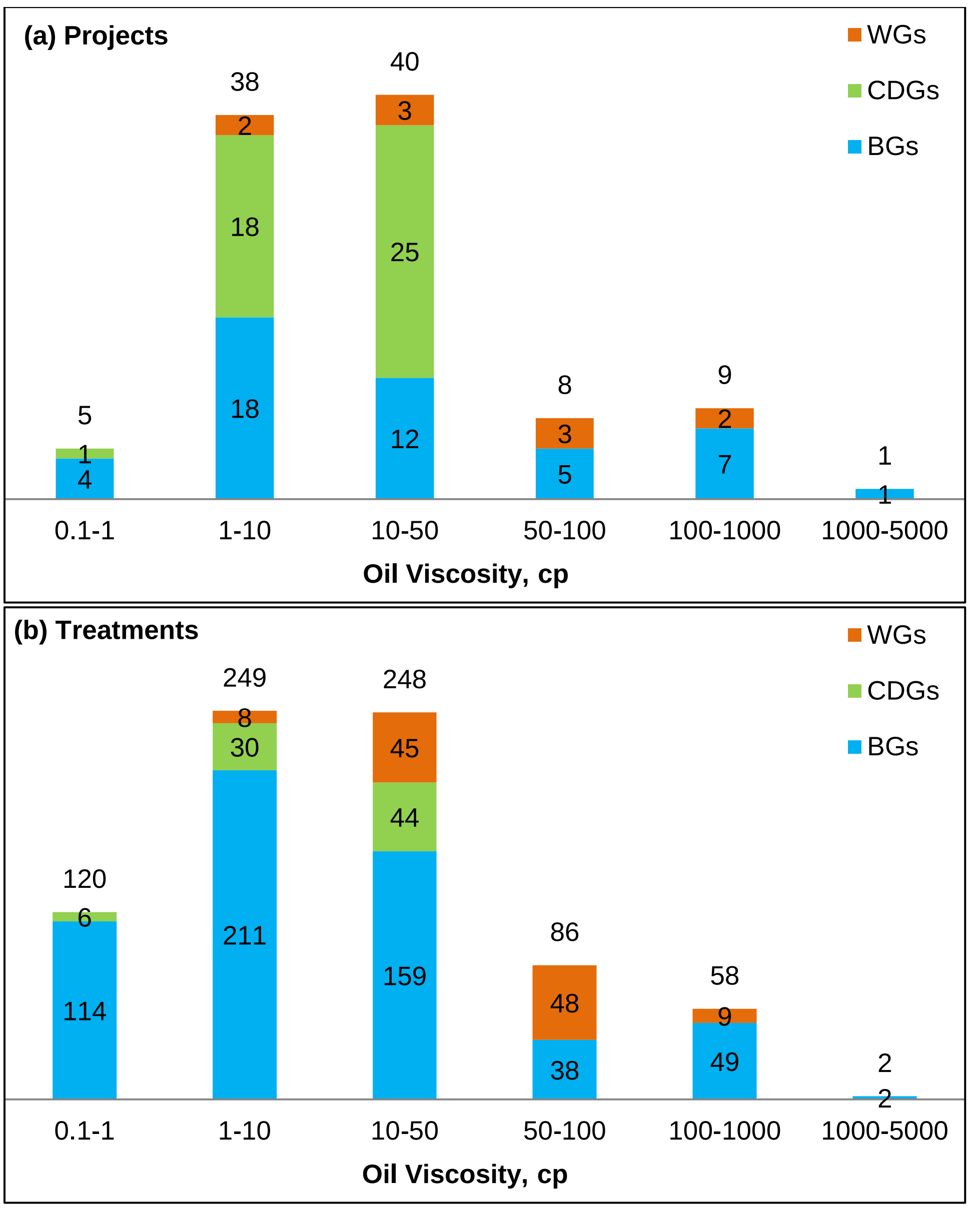

Figure 14. Oil viscosity distributions for (a) polymer gel projects and (b) treatments

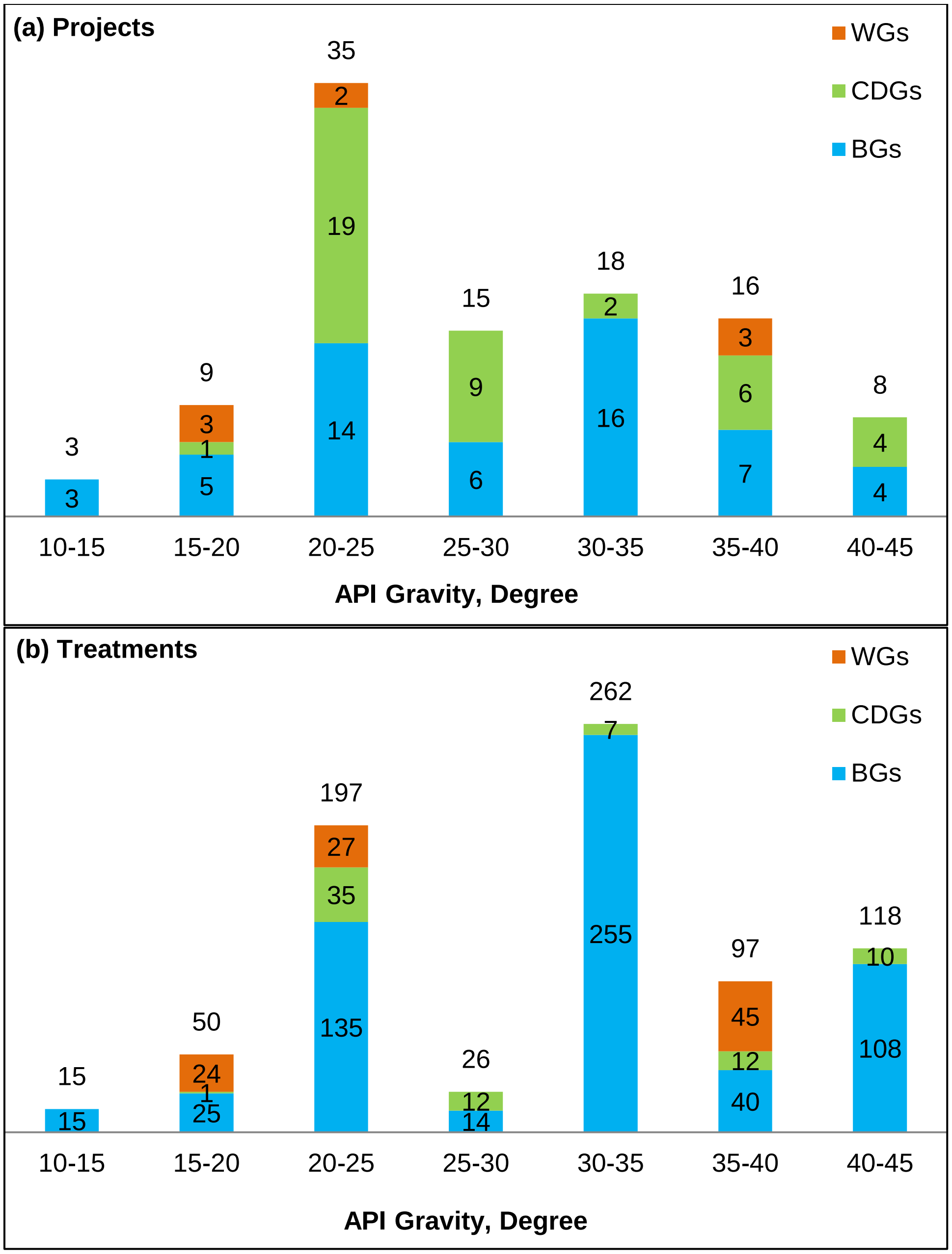

Figure 15. Oil API gravity distributions for polymer gel (a) projects and (b) treatments

Therefore, a data filling attempt has been performed by taking advantage of the good correlation power between the mobility ratio and viscosity (R^2 = 0.66); however, the extracted application limits remain unchanged except for the lower bound of the WGs which reduced from 9.4 to 4. Consequently, the original data set has been not updated with the estimated values.

Mobility ratio data are distributed over a wide range of 0.6-80 with a median of 4 and MAR of 1-5. Figure 17 indicates that all agents have been primarily applied in adverse mobility conditions. Only four cases have mobility ratios of less than one, and weak gels have been applied in more adverse mobility conditions than CDGs. It is important to note that the cases in which CDGs have been applied in favorable mobility conditions are naturally fractured reservoirs like Townsend Newcastle and East Burke Ranch units.

Pretreatment Water Cut. We noticed that the gel systems of interest have been utilized at different stages of the flood life. This introduces the possibility that treatment timing affects the designs and responses of the remediation. Normally, values of the pretreatment water cut of the offset producers are utilized to represent treatment timing in the pattern life. For the summarized field trials, the provided water cuts are either the composite values of all affected wells and/or patterns, or that of a representative treatment and/or producer. The analyses shown by Figure 18 illustrate that polymer gels have been applied over the entire WC range from zero to one, yet half of the projects for which this parameter is provided have been performed at WC > 84% as indicated by the median of the data set. Interestingly, BG projects are distributed only over the upper half of the water cut range. It is obvious that the primary purpose was to reduce water production by blocking the high conductive zones. Also, CDG and WG projects are distributed over the whole parameter range which implies that these systems have been used for multiple purposes, as preventive and reactive treatments.

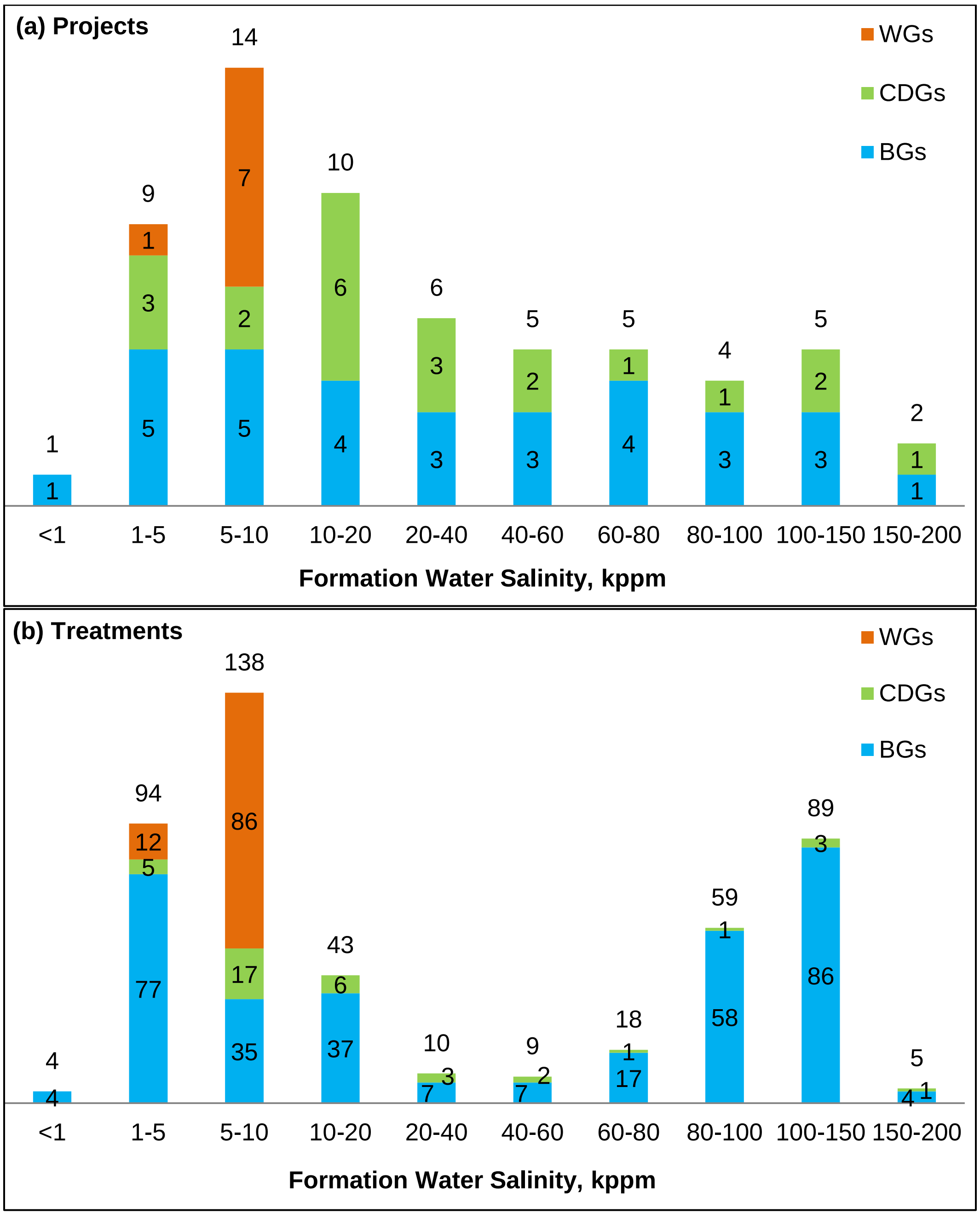

Figure 16. Formation water salinity distributions for (a) polymer gel projects and (b) treatments

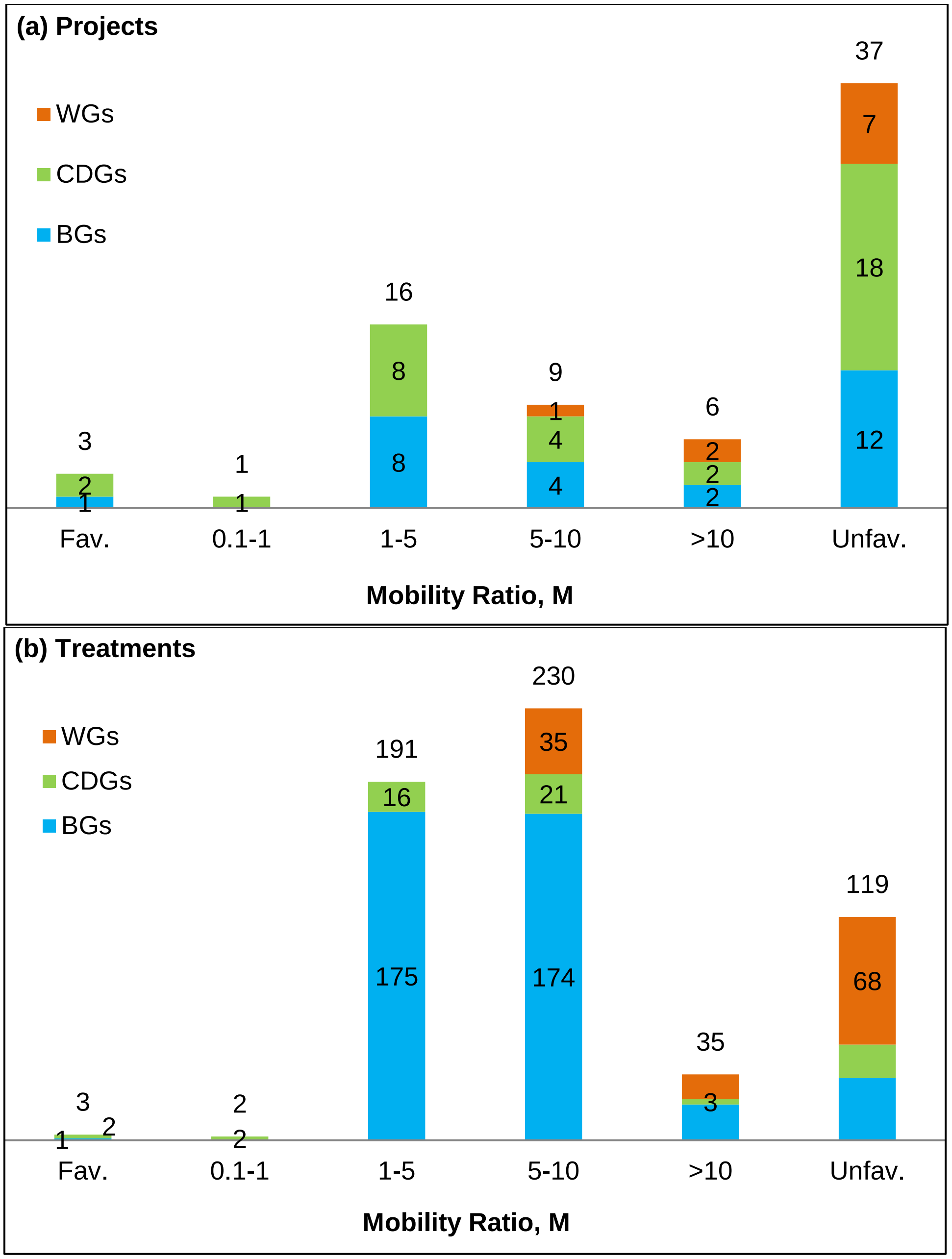

Figure 17. Mobility ratio distributions for (a) polymer gel projects and (b) treatments

It is important to note that CDGs have higher projects frequencies 56% in a 0-10% water cut interval and 19% in the 90-100% water cut interval; however, WGs have low frequency 10% in the first interval and higher frequencies 50% in the second interval. It is important to note that some history cases have emphasized that the sooner the remediation is applied, the better responses to be obtained (Manrique and Lantz, 2011; Lantz and North, 2014; Pipes and Schoeling 2014).

Flood Maturity. This criterion is used to guarantee the existence of quantifiable amounts of the producible fluids (bypassed reserves) to be targeted by gel treatments, which are necessary to establish the economic feasibility of gel projects. In other words, it refers to the evaluation of the evidences of presence of moveable oil in problematic patterns to ensure the projects' economics. In literature, current oil saturation, recovery factor, and the present OOIP percent (remaining reserves) have been used to infer flood maturity. In terms of these factors, many studies have emphasized that this aspects, (i.e., flood maturity) is the most important screening criterion (Smith and Larson, 1997; Delgadillo, 2010; Manrique et al, 2014). It is important to note that the provided values for these parameters are the average estimates for the fields not for the targeted patterns.

Many studies have utilized the low recovery efficiency of the IOR/EOR recovery processes as an indicator for the existence of severe heterogeneities and large amounts of mobile oil to be targeted by gel treatments. Perez et al. (2012) mentioned that recovery factors (primary and secondary) of less than 33% is sometimes used as a rule of thumb to verify the availability of quantifiable mobile oil saturation. Montoya Moreno et al. (2014) added that this criterion is frequently satisfied in the case of fracture communication between injection and production wells.

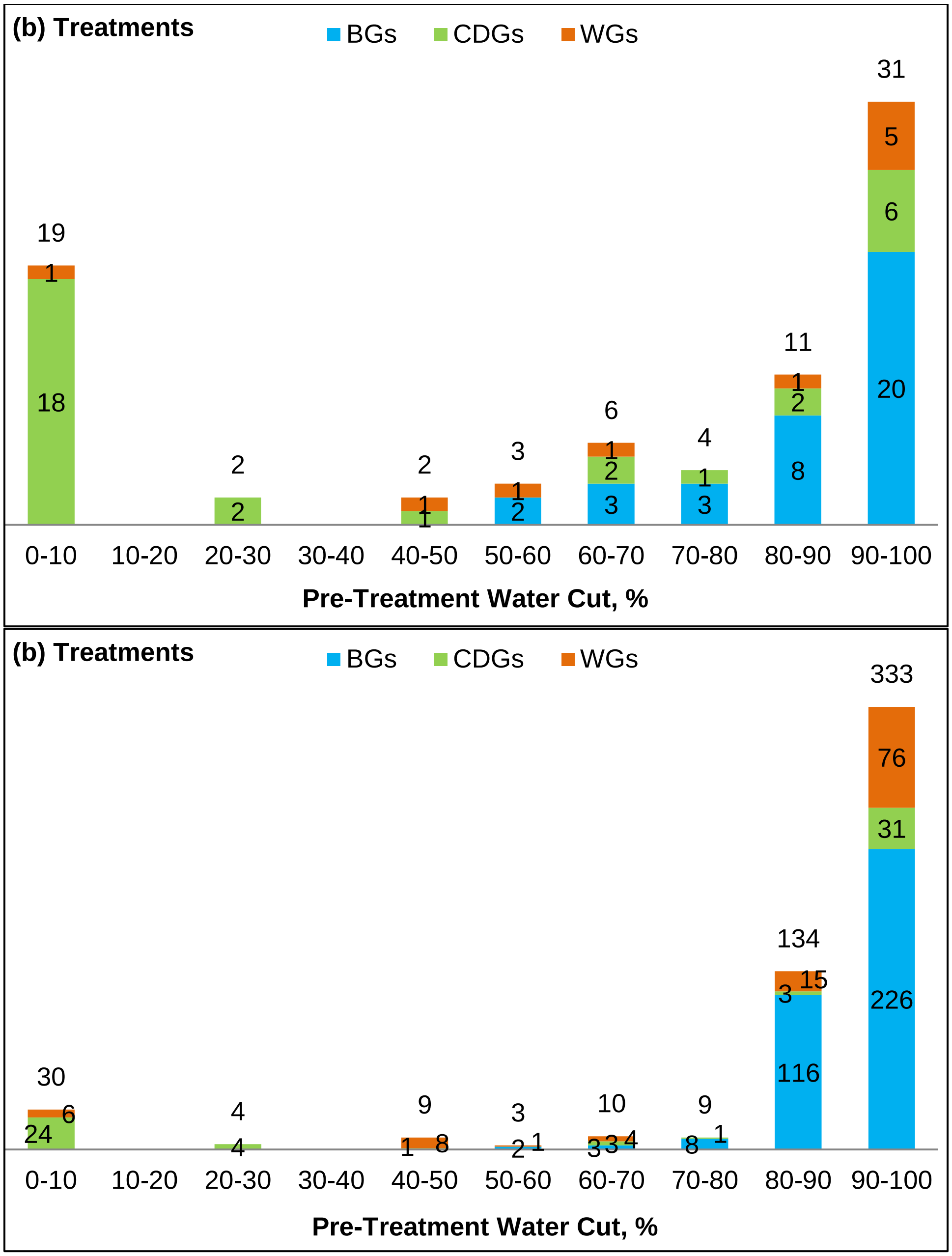

Figure 18. Pre-treatment water cut distributions for (a) polymer gel projects and (b) treatments

Regarding oil saturation, only five historic cases have estimated this property. Studies of Lagomar (Romero et al. 2003), Dina Cretaceous (Lobo et al. 2013), and the Loma Alta Sur (Diaz et al. 2015) fields provide good detailed presentations of the oil saturation in targeted patterns using material-balance calculations and reservoir simulation. Based on these estimations, oil saturations are in range of 0.53-0.73 for BGs and CDGs where no data are reported for WGs. However, there is no clear distinction of whether these saturations are in the swept zones or in the less conductive layers.

In contrast, many gel field projects 76 supplied the recovery factor for different objectives. Figure 19 shows that polymer gels have generally been applied in floods with less than 49% recovery factors. Although the gel projects are distributed over a wide range of 1.6-49%, a large portion 71% of the trials is in the 5-30% interval with a median of 15.7%. While 10% of the projects are in the recovery factor extent >40%, treatments allocation of 22% show a high degree of applicability with a TPP of 13 and comparable frequencies to other regions. This implies the existence of severe heterogeneities in these cases that resulted in bypassing of large quantities of moveable oil. It highlights also the importance of using the treatment frequencies in drawing sound inferences about the application of gel technologies.

Individually, BG data are skewed to the right and this technology was uniquely applied in >40% recovery factor ranges. CDG data are skewed to the left where 83% of the trials are in less than 20% recovery intervals, the matter which reflects the early application of this technology. WGs have few data and are distributed in the middle recovery factor intervals.

Recognizing that subsequent injection operations will cause oil displacement and production after gel treatment (especially for BGs and cyclic fashion of CDG and WG applications) reveals that the applied IOR/EOR recovery process requirements should be met to achieve the feasibility of gel projects. Also, these recovery methods have different working limits for oil saturations; for example, Taber et al. (1997) showed that CO_2 flooding (>20 %) can be applied at much less saturations than polymer flooding (>50%).

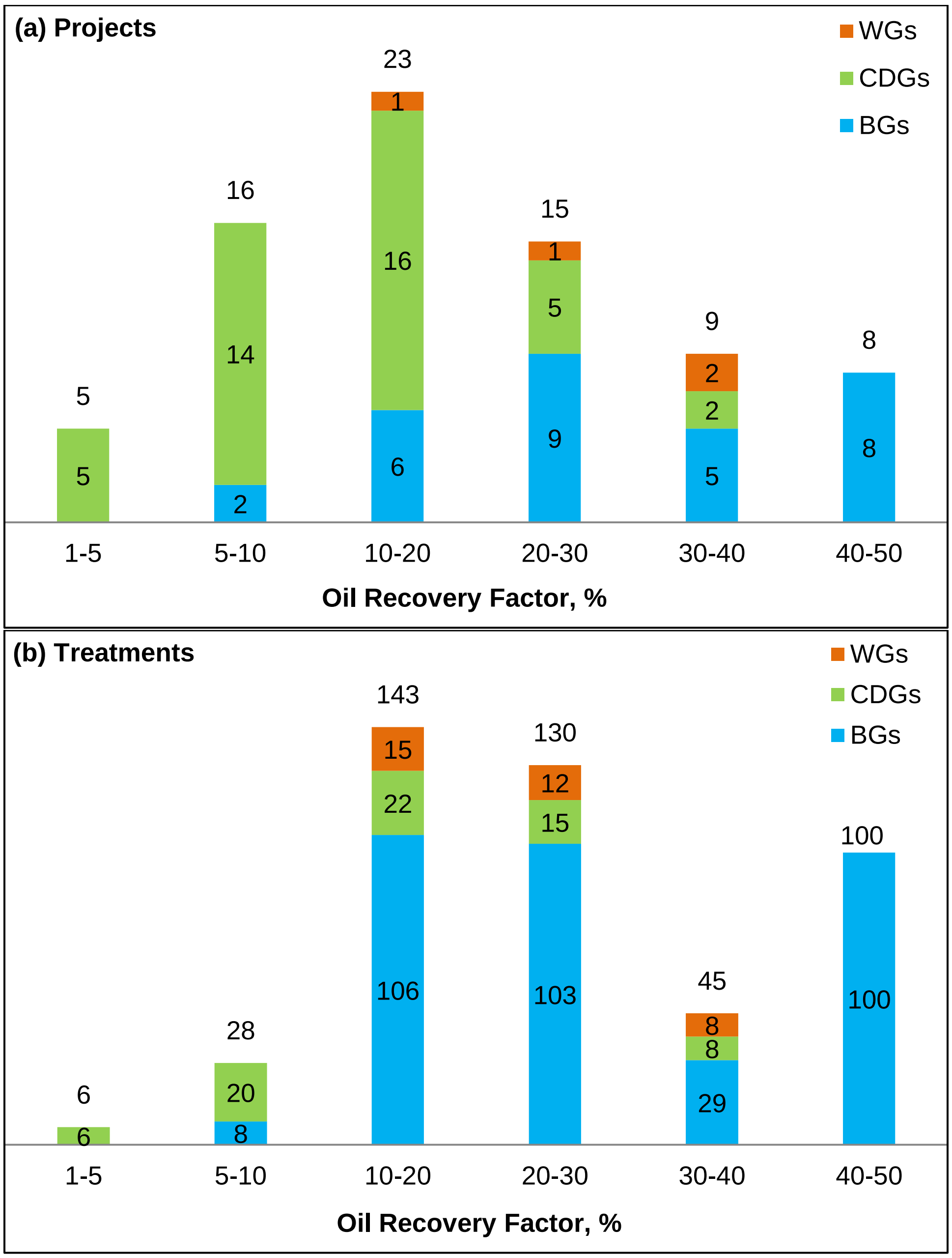

Figure 19. Oil recovery factor distributions for polymer gel (a) projects and (b) treatments

Therefore, we have processed recovery factor data according to the ongoing recovery processes in the targeted fields to ensure projects economics as shown by Figure 20. Lantz (2010), Sandoval et al. (2010), Mack and Lantz (2013), and the ICP methodology presented by Castro et al. (2013) and Maya et al. (2014) showed in their basic decision making scheme for chemical flooding that in case of mature water floods with high recovery factors, there is low probability of success for conformance technologies and there is a need for a combination of sweep improvement and residual oil saturation reduction technologies. They pointed out that in these cases; the surfactant-based technologies (ASP/ SP) are the candidates.

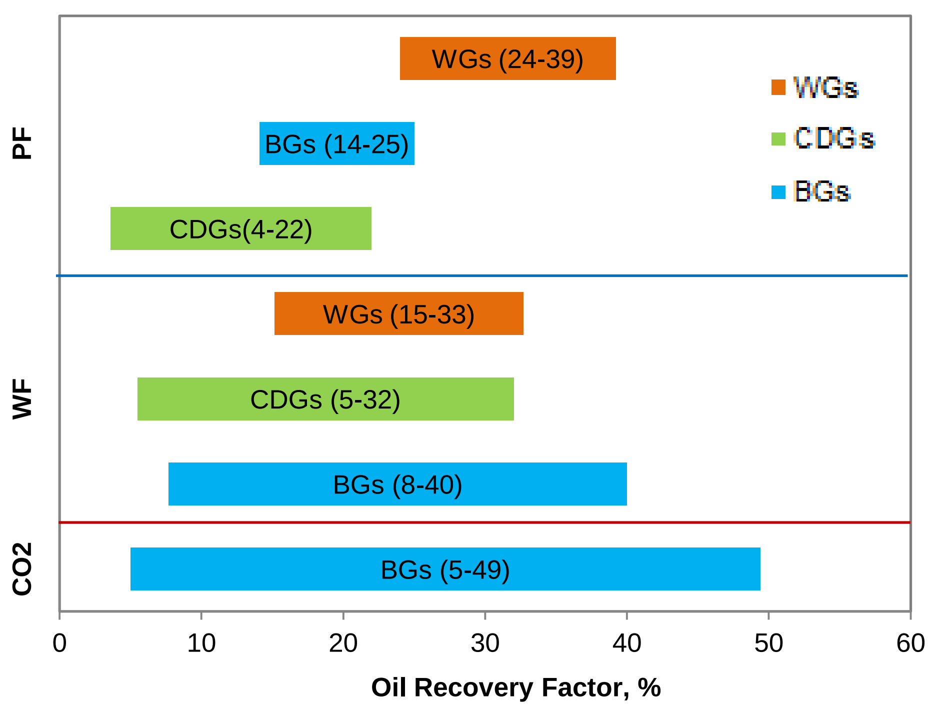

Figure 20. Ranges of recovery factor at startup of gel projects categorized according to IOR/EOR process

Comparisons of Polymer Gels Applicability Guidelines

Generally, the most prominent feature of our screening guidelines is their comprehensiveness of the most widely applied injection well remediation technologies, with all the essential parameters (16) for their technical screening. Thus, they provide an integrated identification system of the potential treating agent for the candidate injection wells. In addition to improving the established guidelines for MCAP-BGs, CDGs, and WGs, screening criteria for organically crosslinked bulk gels were established in this research for the first time. We have included the permeability variability and mobility ratio to illustrate the roots of the conformance issues; formation types and ongoing EOR process to show differences in the application conditions and compatibility with the drive-fluids. Water cut data were also used to point out the differences in treatment timing among conformance agents of interest.

Additionally, as dual-frequency guidelines, the proposed criteria provide a way to verify the appropriateness of the drawn validity limits for different properties through examining treatment frequencies in addition to project statistics. Differences between both statistics are of extreme importance as they correct the false indicators seen in single distribution histograms. Also, the most favorable conditions for applying gel techniques have been determined through identifying the denser property ranges and introducing them as the most applied ranges to distinguish them from other ranges.

Moreover, this study has overcome some of the cons found in the preceding studies like the biases to a certain region or gel system, considering different polymer types, and utilization of mixed data for some parameters. This accomplished through considering all polyacrylamide polymer-based gel projects available in the public domain and processing of mixed data according to the influential aspects like formation type. The present project review includes gels field trials from 1978 to 2015 which resulted in updated criteria. Many experience-based limits were replaced with detailed validity ranges of different parameters for different treating agents as it shown in the next paragraph.

Individually, Table 7 compares present and former screening criteria of different gel technologies. For CDGs, the present criteria have extended limits of DPc (0.9 vs. 0.7), oil viscosity (40 vs. 30 cp), and water salinity (131 vs. 100 kppm); however, they have lower permeability (850 vs. 4200 md) and temperature (202 vs. 210°F). While all studies reported the same lithology, the present work indicates the application of CDGs in naturally fractured sandstones (five cases) in addition to matrix-rock formations (primary). Also, it is important to note that we have identified application of CDGs in some unconsolidated sandstones in Chinese oilfields; however, they are not included in this study. To examine if CDGs are really alternatives for polymer flooding as stated by some studies (Castro et al. 2013), we compared the developed CDGs guidelines with polymer flooding criteria recently published by Saleh et al. (2014) in Figure 21. Interestingly, this figure shows that CDG guidelines are completely within polymer flooding application conditions; this would imply that CDGs have been used instead of polymer flooding to sweep reservoirs in which the adverse mobility ratio is accompanied by high permeability variation. However, this comparison was not sufficient to draw a satisfactory conclusion about these technologies because of the absence of the most discriminant parameter in polymer flooding criteria, the reservoir heterogeneity.

Table 6. Summary of Quantitative Screening Parameters for Application of Polymer Gels in Injection Wells

Property Unit	ϕ %	k md	DPc fraction	T °F	h ft	D ft	μ cp	API degree	Sal kppm	M ratio	WC %	RF %	Lithology Formation	IOR/EOR Process
							MCAP-Bulk Gels							
Points Count	46	45	25	46	42	46	39	44	26	10	31	26		
Mean	17.8	209	0.82	139	122	5292	53	27	36.9	11	88	27	***Carbonate*** Matrix-rock	
Median	17	68	0.82	125	67	4742	10	28	20	3	94	25	Nat. Fractured	
St. Dev.	7	318	0.06	37	143	2471	110	7	33.5	24	14	13		*WF* *PF* *CO_2*
CV	0.38	1.5	0.08	0.27	1.17	0.47	2.09	0.26	0.91	2.13	0.15	0.47	***Sandstone***	
Min	8	3	0.65	72	8	975	1	12	0.15	1	52	5	Matrix-rocks	
Max	35	1216	0.91	208	670	10000	600	42	100	80	100	49.4	Nat. Fractured Unconsolidated	
MAR	0.1-0.3	10-500	0.8-0.9	100-200	-	-	1-260	20-35	-	1-5	70-100	20-30		
							OCAP-Bulk Gels							
Points Count	4	4	2	4	3	4	4	4	2	2	3	2		
Mean	24.6	1037	0.81	306	247	5866	1383	20	3.8	12	84	32	***Carbonate***	
Median	26	810	0.81	300	300	5027	364	19	3.8	12	83	32	Matrix-rock	
St. Dev.	13	1124	0.01	32	185	5546	2301	9	1.13	3	5	9		*WF* *CO2* *Steam*
CV	0.52	1.08	0.02	0.10	0.75	0.95	1.66	0.44	0.30	0.29	0.06	0.29		
Min	10	30	0.80	275	42	910	3	12	3	9	80	25	***Sandstone***	
Max	36	2500	0.82	350.3	400	12500	4800	31	4.6	14	90	38	Matrix-rock Unconsolidated	
MAR	-	-	-	250-350	-	-	-	35-40	-	-	-	20-40		

Table 6. Summary of Quantitative Screening Parameters for Application of Polymer Gels in Injection Wells (Cont'd)

Property Unit	ϕ %	k md	DPc fraction	T °F	h ft	D ft	μ cp	API degree	Sal kppm	M ratio	WC %	RF %	Lithology Formation	IOR/EOR Process
							Colloidal Dispersion Gels							
Points Count	37	33	35	37	32	37	37	34	19	14	29	35		
Mean	17.4	201.23	0.74	147	39	6405	13.7	26	34.4	6	29	13		
Median	16.5	142	0.74	143	26	6900	12	24	18.4	4	0.4	11		
St. Dev.	3.5	204	0.09	31	42	2345	11	7	37.5	5	39	7	***Sandstone*** Matrix-rock Nat. Fractured	*WF* *PF*
CV	0.20	1.01	0.12	0.21	1.06	0.37	0.78	0.26	1.09	0.85	1.31	0.59		
Min	10.4	7.8	0.50	72	5	300	1	18.5	3.03	0.6	0	3.6		
Max	26	850	0.90	202	200	9791	40	42.5	131.1	17	96	32		
MAR	0.1-0.25	10-500	0.6-0.9	100-200	-	-	1-40	20-25	-	1-10	-	5-20		
							Weak Gels							
Points Count	10	10	6	10	9	10	10	8	8	3	10	4		
Mean	27.6	1377	0.75	139	67	4497	120	25	5.6	16.5	71	28		
Median	29	1439	1	147	50	4037	42	21	5.9	13	88	28		
St. Dev.	5.2	819	0	20	58	1637	215	9	1.5	9	31	10	***Sandstone*** Matrix-rock Unconsolidated	*WF* *PF*
CV	0.19	0.59	0.14	0.14	0.87	0.36	1.79	0.37	0.28	0.56	0.43	0.38		
Min	20	19	0.60	109	18	3051	7.8	15.4	2.12	9.4	0	15		
Max	34	2634	0.91	163	213	8727	706	37.4	7	27	97.3	39		
MAR	-	-	0.7-0.8	100-150	-	-	12-75	-	5-7	-	60-100	-		

With respect to metallic crosslinked bulk gels, detailed evaluations for permeability variation (DPc), net thickness, depth, oil gravity, water salinity, and oil viscosity included or replaced the experts' opinions in the previous studies. In comparison with the Seright and Liang projects survey, present criteria have less number of projects (56 vs. 114), lower permeability (1216 vs. 5000 md), and narrower temperature ranges (208 vs. 240 °F). However, their survey included 48 polyacrylamide, 29 xanthan, 10 other materials, and 27 unknown compositions gel projects. Also, no information was provided regarding types of crosslinking agents used for projects in this study.

Table 7. Extensive Comparison of Applicability Criteria of Two Gel Technologies

Colloidal Dispersion Gels (CDGs)								
Parameter	**Mack**		**Williams & Pitts**		**Manrique et al.**		**Current Study**	
	Min	Max	Min	Max	Min	Max	Min	Max
Survey Years	1974	1978	1994	1996	2005	2014	1976	2015
# of Projects	3		2		31		44	
Publishing year	1978		1997		2014		2016	
Lithology	Sandstone		Sandstone		Sandstone		Sandstone	
Formation type	Matrix		Matrix		Matrix		Matrix and Nat. Fractured	
Permeability, md	10	300	50	-	10	4200	7.8	850
DPc, fraction	0.6	-	-	-	0.55	0.7 *	0.5	0.9
Temperature, °F	-	220	-	200	80	210	72	202
Average Net Pay, ft	-	-	NC	NC	20	200	5	200
Depth, ft	-	-	-	9000	-	-	300	9791
Oil Sat. (start),%	-	-	-	-	-	-	53	73
Oil Viscosity, cp	-	-	-	400	5	30	1	40
Oil Gravity, API	-	-	15	40	-	-	18.5	42.5
Water Salinity, kppm	-	100	Acceptable		-	-	3	131
Water Cut, %	NC	NC	-	-	-	-	0	96
Mobility Ratio	-	-	-	-	-	-	0.6	17
Oil Recover (start), %	-	33	-	-	-	-	3.6	32

Table 7. Extensive Comparison of Applicability Criteria of Two Gel Technologies (Cont'd)

Metallic Crosslinked Bulk Gels (MCAP-BGs)								
Parameter	**Seright & Liang**		**Williams & Pitts**		**Delgadillo**		**Current Study**	
	Min	Max	Min	Max	Min	Max	Min	Max
Survey Years	1980	1992	1990	1996	-	-	1978	2015
# of Projects	114		4		-		57	
Publishing year	1994		1997		2010		2016	
Formation type	Carbonate Sandstone		Carbonate Sandston		Sandstone Carbonate		Carbonate Sandstone	
Polymer type	HPAM, Xanthan, Others		HPAM		HPAM		HPAM	
Permeability, md	4.1	5000	NC	NC	15	-	3	1216
DPc, fraction	-	-	-	-	0.63	-	0.65	0.91
Temperature, °F	64	240		<250	-	208	72	208
Average Net Pay, ft	-	-	NC	NC	-	-	8	670
Depth, ft	-	-	-	11000	-	8000	975	10000
Oil Sat. (start),%	-	-	-	-	10	-	53	70
Oil Viscosity, cp	-	-	NC	NC	-	200	1	600
Oil Gravity, API	-	-	NC	NC	18	-	12	42
Water Salinity, kppm	-	-	Acceptable		-	70	0.15	100
Water Cut, %	9	99.4	-	-	-	-	52	100
Oil Recover (start), %	1.1	73	-	-	-	-	5	49

* From Castro et al. (2013).

Remarkably, Figure 22 shows that the applicability criteria of gel systems are quite different and frequently intersected with each other over wide intervals. This implies that these systems provide solutions for a wide variety of conformance problems, and for a given situation, there is a possibility that more than one treating agent is the potential technology. To demonstrate that, we have considered three dual-agent history cases of Ash Minnelusa, El Tordillo, and North Rainbow fields. For example, in El Tordillo field two injection patterns were successively treated with BGs and CDGs to obtain more uniform distribution of injection water. Interestingly, the new guidelines have correctly predicted the applicable gel systems for three dual-agent history cases as shown by Figure 23 for the Ash Minnelusa unit. It is noteworthy that Muruaga et al. (2008) have pointed out that El Tordillo field and many waterfloods exhibit two types of heterogeneities.

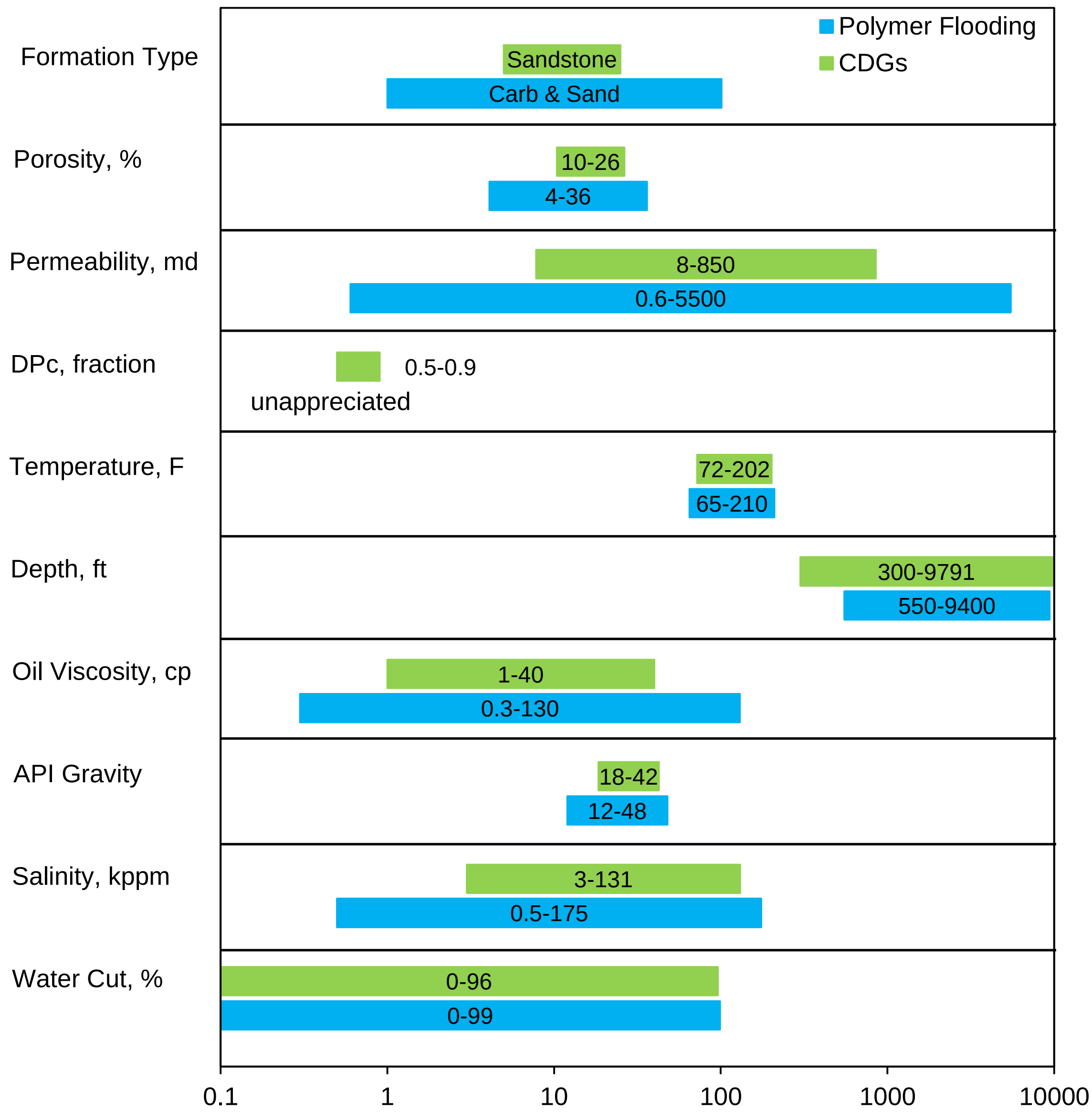

Figure 21. Comparison of applicability guidelines of CDGs and polymer flooding (Saleh et al. 2014)

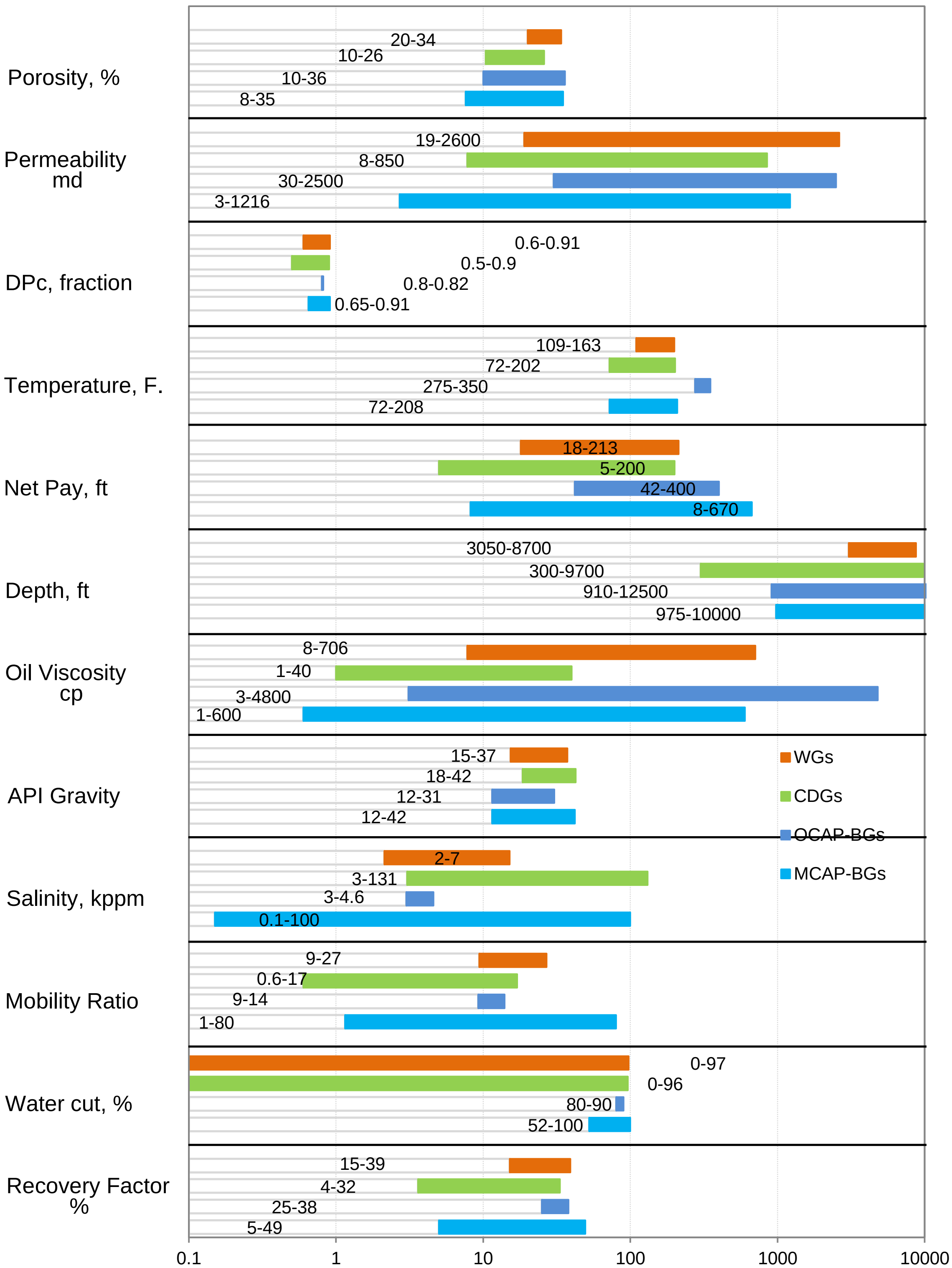

Figure 22. Comparison of developed screening criteria for gel technologies

Polymer Gels Quick Screening Table

Field Ash Minnelusa

Porperties	Values	MCAP-Bulk Gels	OCAP-Bulk Gels	Collodial Dispersion Gels	Weak Gels
Lithology	Sandstone	Carb & SS	Carb & SS	Sandstone	Sandstone
Formation	Matrix-rock	All	Mat & Unc	Mat & NF	Mat & Unc
IOR/EOR Process	Polymer flooding	WF,PF,CO2	WF,CO2,Steam	WF,PF	WF,PF
Porosity, %	16.3	8-35	10-36	10-26	20-34
Permeability, md	300	3-2500	30-2500	8-850	19-2634
DPC, fraction	0.8	0.65-0.91	0.8-0.82	0.5-0.9	0.6-0.91
Temperature, F	140	72-208	275-350	72-202	109-199
Net Thickness, ft	21	8-670	42-400	5-200	18-213
Depth, ft	7775	975-10000	910-12500	300-9791	3051-8727
Oil Viscosity, cp	30	0.8-600	3-4800	1-40	9.5-706
API Gravity, deg.	20	11-42	12-31	18-42	15-37
Water Salinity, ppm	67382	150-100,000	3000-4600	3000-130,000	2000-7000
Mobility Ratio, M	9.24	1-80	9-14	0.6-17	9-27
Water Cut, %	67.3	52-100	80-90	0-96	0-97
Recovery Factor, %	14.1	5-45	25-38	4-32	15-39

Green = Satisified
Red = Unsatisifed

Figure 23. Application of the developed guidelines for a dual-agent history case

The improved guidelines presented in this paper can assist reservoir engineers in identifying a potential treating agent or a combination of two agents, and indicate the feasibility of the gel treatments by providing numbers of projects and treatments implemented in similar conditions to that of the field under evaluation.

Conclusions

1. For IOR/EOR processes, SPE papers offer a consistent, high quality, multi-stage data source in comparison to the Oil and Gas Journal Surveys.
2. Gel technologies have received modest attention in the course of applicability evaluations when compared to other EOR methods for which a large number of screening criteria were developed and appeared in the literature.

3. In IOR/EOR world, data cleaning process should strengthen the statistical approaches by the reservoir engineering viewpoints and the possibility of the existence of special cases. This is extremely important as there are many factors that may affect these data such as the formation type and the ongoing EOR process.
4. Imputation methods that maintain the original variability of the incomplete data sets do not influence the validity limits of the technical guidelines; however, they should be avoided if MAR statistics are favorable.
5. The screening parameters considered for common EOR processes are not enough to capture the whole picture of the conformance problems and to develop a consolidated evaluation scheme for polymer gels.
6. The lithology and formation type have significant effects on the applicability limits of some reservoir properties such as porosity, permeability, depth, and oil viscosity.
7. For naturally fractured systems, it is extremely important to recognize whether the reported permeability values are for the matrix-rock block or the natural fractures. If there are of matrix-rock, then these values are mixed data.
8. For screening purposes, mixed data sets should be analyzed according to the affecting aspects such as formation type and IOR/EOR process. Otherwise, they will falsify where polymer gels have actually been applied.
9. Permeability variation is the main cause of selecting polymer gels despite the fact that some systems have the ability to address other water production problem

root. Also, selecting the appropriate treating agent should not depend solely on one property, such as permeability variation.

10. Improved, updated applicability guidelines were developed for polymer gels that are extended in terms of screening parameters and statistical attributes. They also include three operational aspects in addition to reservoir and fluids characteristics.
11. In the present guidelines, for the first time, permeability variation and mobility ratio have been considered and elaborately evaluated rather than introduced as experts' opinions.
12. The developed guidelines facilitate multiple screening of different treating agents which is crucial when reservoirs have different heterogeneities.
13. The novelty of the developed guidelines is in their ability to self-checking the established application conditions as a result of inclusion and simultaneous assessment of the project and treatment frequencies.
14. Gels systems provide solutions for a wide variety of conformance problems. For a given situation, there is a possibility that more than one agent is the candidate, and the selection depends on the objectives and purposes of the remediation among other factors.

Nomenclature

BGs =	Bulk Gels
CDGs =	Colloidal Dispersion Gels
CO_2 =	Carbon-dioxide flooding
CV =	Coefficient of variation
D =	Reservoir depth, ft

DPc =	Dykstra-Parsons coefficient, fraction
h =	Average net pay thickness, ft
k =	Permeability, md
MAR =	Most applied range
Mat. =	Matrix-rock
NC =	Not critical
NF. =	Naturally fractured reservoirs
St. Dev =	Standard Deviation
Q1 =	First quartile
Q3 =	Third quartile
IQR =	Interquartile range
PF =	Polymer flooding
Steam =	Steam injection
T =	Temperature, °F
TPP =	Treatment per project
Uncon. =	Unconsolidated formation
WC =	Water cut, %
WF =	Waterflooding
WGs =	Weak Gels
ϕ =	Porosity, %
μ =	Oil viscosity, cp

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II. A Roadmap to Successfully Select a Proper Gel Treatment Technology

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Abstract

Polymer gels have been effectively applied to extend the productive life of mature oilfields by mitigating water production and enabling the recovery of bypassed oil reserves. A key component for a successful conformance improvement treatment is the identification of the most appropriate gel technology for a targeted reservoir. Gel projects are capital sensitive and involve high degree of risk; therefore, it is crucial to select a proper gel technology and provide an optimized design project.

This paper presents the first generalized comprehensive selection system for injection well gel technologies based on the comparative analyses of the characteristics of conformance problems in gel field projects. 111 field trials of three in-situ gel systems including bulk gels, colloidal dispersion gels, and weak gels were summarized from 1978 to 2015. First, reservoir/fluids characteristics, diagnosis indicators used in the evaluation of drive-fluid channeling strength, and treatment operational parameters were summarized. Then, problem zone volumes were estimated using a design rule of thumb and the problem development status was indicated using some production-related

parameters. Finally, all characteristics of conformance problems were compared for different gel systems to identify factors implicitly used in the nomination of gel technologies in the field projects.

We recognized that gel selection process starts by matching characteristics of conformance problems with technical specifications and mechanisms of the gel systems. Then, the initial candidate technology is confirmed by screening criteria to ensure gel system compatibilities with reservoir and injected fluids. We identified that the most influential characteristics in the selection process are drive-fluid channeling strength, volume of problem zone, problem development status, existence of cross-flow, and the nature of the required solution whether it depends on gel strength or volume. It was recognized that the existence of crossflow or high oil saturation in the offending zones turns a limited conformance problem into a large volume issue that needs the application of the flood-size treating technologies. For these situations, current oil saturation in the problem zones is the key factor rather than oil saturation in the less conductive zones because it is guaranteed by the high reservoir permeability heterogeneities. In addition, the problem development status does not only affect the selection of a gel system, but also its design parameters such as polymer concentration. The novelty of the new gel selection system is in its utilization of standardized general parameters and provision of distinct parameter cut-offs for each gel technology.

Introduction

Excessive water production represents a major industry challenge because of its serious economic and environmental impacts. The problem of producing and disposing of large quantities of injection water is becoming more crucial due to the tightening economic constraints caused by the falling oil prices. Gel technologies have been proven to be effective in addressing this problem and in increasing oil recovery. However, selecting a proper gel technology is not an easy task for the oilfield engineers due to many reasons. The costly diagnosis techniques required to evaluate conformance issues make gel selection process extremely important in these capital sensitive gel projects.

Conformance problems encompass a broad range of issues that may exist anywhere from the wellbore to deeply in the reservoir. In particular, reservoir conformance issues have many types as their main root (permeability spatial variation) occurs in various forms and directions. Polymer gels also have a wide range of forms and chemistries that function by different mechanisms to improve the sweep efficiency of an enhanced oil recovery (EOR) process. Moreover, the selection process is further complicated by the fact that the treatment of a specific conformance issue requires a distinct gel technology.

Additionally, characteristics of conformance issues are qualitatively evaluated using several diagnosing techniques along with the traditional geological and reservoir characterization. The nature of this evaluation has made the selection process to be nominally performed using the problem type or description. This judgmental approach has resulted in the emergence of many diverging opinions about the applicability of polymer gels (Chou et al. 1994). There have been more qualitative problem descriptions and terminologies than the conformance problems themselves. In addition, this evaluation has resulted in a difficulty in the recognition of distinctive channeling severity limits for gel systems. Consequently, conformance problems in all reviewed case histories were characterized as strong channeling issues. On the other hand, the choice of the gel technologies has been solely based on the drive-fluid channeling strength in field applications while it involves other important factors as will illustrate in the next sections.

Several studies have focused on the classification and connection of conformance problems and solutions in general (Azari and Soliman, 1996; Seright et al. 2001; Smith, 2006; Joseph and Ajienka, 2010). For gel technologies, a number of qualitative selection matrices or candidate selection criteria have been published mainly for bulk gels based on the Permian and Powder River Basins' experiences. These studies have ultimately concentrated on distinguishing of the channeling strength whether it is fracture-type or matrix-type using numerous problem descriptions and on the sizing of the bulk gel treatments. In addition, flood-size treating technologies have been rarely taken into consideration in these studies where only Sydansk (2007) pointed out to such conformance agents.

Sydansk and Southwell (2000) provided a list of the conformance problems that can be treated by Chromium (III)-Carboxylate/Acrylamide-Polymer (CC/AP) gels. They have illustrated that there are two problem key distinctions that must be made in order to identify the appropriate gel system. First, a conformance problem should be differentiated whether it is a vertical or an areal issue and whether there is fluid crossflow between geological strata or not. The second key distinction is whether the high conductive zone is simple high permeability unfractured matrix rock or it is a high permeability anomaly such as fractures. Later, their work has been translated into the following well-known rule of thumb for gel technology selection. This rule states that bulk gels are designed to reduce water channeling in extreme heterogeneities like naturally fractured formations or in reservoirs with multi-Darcy permeability anomalies. For unfractured, low permeability matrix-rock reservoirs, sweep efficiency can be improved by large volume colloidal dispersion gel (CDG) treatments (Al-Dhafeeri et al. 2005; Norman et al. 2006; Muruaga et al. 2008; Diaz et al. 2008). It is noteworthy that they justified the utilization of the CDGs by the presence of crossflow between reservoir layers.

Seright et al. (2001) classified water production problems into four categories based on the conformance treatment type and ranked them in term of the remediation difficulty. They also proposed a diagnostic strategy to decide whether the flow around the wellbore is radial or linear; however, only treatment-size technologies have been considered in this study with respect to polymer gels. Reynolds and Kiker (2003) suggested the injection of CDGs at the inception of waterflooding if analogous floods suggests a premature water breakthrough or Dykstra-Parsons coefficient is greater than 0.6. They proposed the injection of BGs after waterflooding initiation if water channeling is through fractures or high permeability streaks. Liu et al. (2006) presented conformance problems in Chinese oilfields, and connected them with a variety of treating agents based on the type of the conformance treatment. They have considered BGs, CDGs, WGs and performed-particle gels in their study, and provided a comprehensive decision-making strategy for the candidate well selection. Smith (2006) presented a Comprehensive Conformance Problem Matrix that classifies issues into wellbore versus far-wellbore problems and high flow conduit versus permeable rock problems based on the severity of the drive-fluid channeling as shown in Figure 1. Most recently, Lantz and Muniz (2014) developed a Polymer Gel Injection Wells Conformance Improvements Matrix with horizontal and vertical axes that display polymer concentrations and gel volumes as a designing tool.

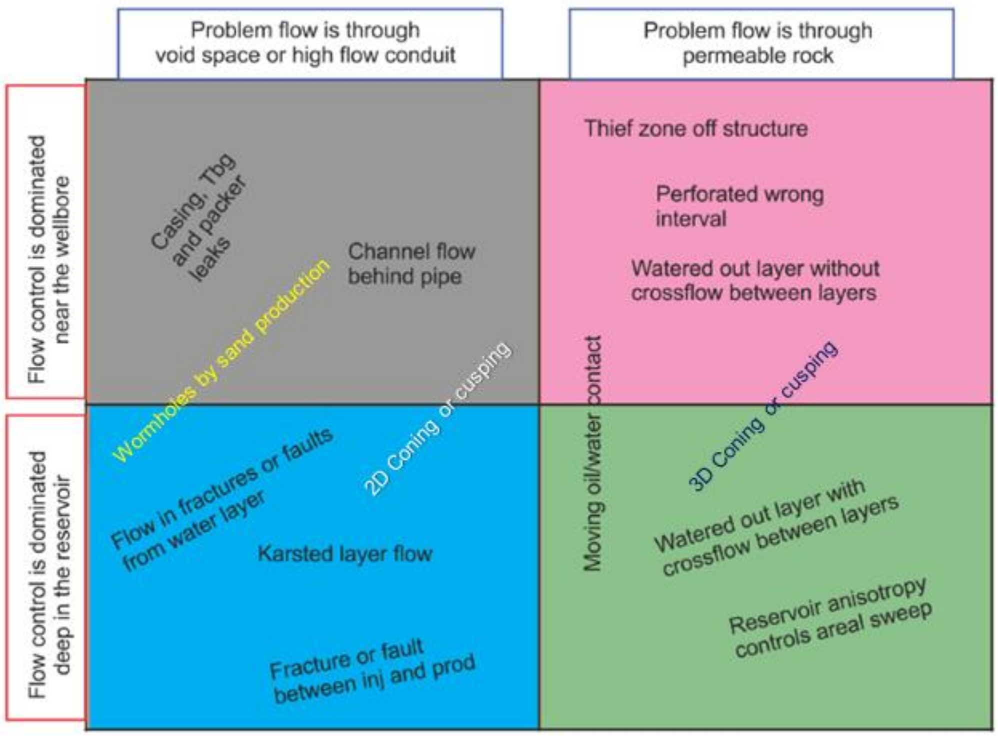

Figure 1. Comprehensive Conformance Problem Matrix (after Smith and Ott, 2006)

This study focuses on identifying the influential parameters in the gel technology identification process and the relationships between these parameters. It aims to develop a holistic selection scheme that is based on generalized parameters rather than subjective descriptions using the field applications of bulk gels, colloidal dispersion gels, and weak gels in injection wells. In this paper, field evaluation results of drive-fluid channeling and the estimations of two characteristics of conformance issues are presented. For each characteristic, the comparative analyses performed to identify key distinctions between gels technologies will briefly discussed. A new problem classification is presented and the characteristics of conformance issues that are treatable by each gel technology are provided and visualized by a roadmap and a selection matrix.

Polymer Gel Conformance Technologies

Polymer gels have been proven to be effective solutions for a variety of conformance issues, especially in injection wells. They can effectively penetrate the offending high conductive zones deep into the reservoir and provide a sustainable diversion to subsequent injected water toward the low permeability zones. Polymer gels are usually classified based on their ingredients, where the gelation process occurs, and the resulting gel structure. Synthetic polyacrylamide-based gels are the most widely applied chemical conformance-improvement system for treating injection wells (Lantz and Muniz, 2014). Polyacrylamides can be either organically (OCAP) or metallically (MCAP) crosslinked depending on type of the crosslinking agent used. In this paper, three partially hydrolyzed polyacrylamide, in-situ gelling conformance systems are considered for screening purposes.

Bulk Gels. Bulk gels (BGs) are probably the most widely applied polymer gel system for conformance improvement purposes (Sydansk and Southwell, 2000, Lantz and Muniz, 2014). These gels can be formed using high molecular weight (8-13 million daltons) partially hydrolyzed polyacrylamides with a crosslinker. The high polymer concentrations result in a continuous semi-solid 3D network structure for the gel. Bulk gels provide a wide range of strengths and a wide range of controllable gelation times; thus, they can be applied to injection or production wells for profile control or water shut-off purposes.

This gel system has two versions depending on the type of crosslinking agent. For MARCIT^{SM} gels developed by Marathon Oil Company, polyacrylamide polymers are crosslinked using a trivalent metal ion which is usually Chromium (III) (Sydansk and Smith 1988). Chromium (III)-Carboxylate/Acrylamide-Polymer (CC/AP) gels are characterized by having robust gel chemistry in water with a wide range of water salinities, being highly insensitive to reservoir interferences. They are resistance to CO_2 and H_2S, easy to implement in field, and cost competiveness (Southwell, 1999). CC/AP gels are applicable over a broad reservoir temperature range; however, extensive laboratory and field cases confirmed that they should be used in a formation temperature of less than 220°F (Sydansk and Southwell 2000). For high temperature applications, medium molecular weight polyacrylamide polymers are crosslinked with an organic agent and a stabilizer to delay the gelation process. In this study, these gels are depicted as organically-crosslinked-polyacrylamides bulk gels (OCAP-BGs). An example of this specialized chemistry is the UNOGEL technology developed by Union Oil Company of California (UNOCAL) which can be applied at temperature ranges of 200 to 300 °F (Norman et al. 2006).

Bulk gels are applied to treat strong drive-fluid channeling that typically occurs in naturally fractured reservoirs and extremely high permeability matrix-rock reservoirs (Smith and Larson 1997). Bulk gels are designed to reduce water production by totally or partially blocking the high conductive zones by reducing their permeabilities. Typical injected volumes of these agents range from a few hundred to tens of thousands of barrels; therefore, offending zones that are small in volumes relative to the size of the reservoir are good candidates. From their state-of-the-art, bulk gels are only considered as plugging agents, or a conformance-control strategy that works solely by correcting the formation permeability heterogeneity.

Colloidal Dispersion Gels. Colloidal Dispersion Gels are in-situ microgels aggregates that are formed by crosslinking of low concentrations (150 to 1200 ppm) of high-molecular-weight (> 22 million daltons) hydrolyzed-polyacrylamide polymer with aluminum citrate or chromic citrate to produce a weak gel. Such low polymer concentrations are not enough to form a continuous network, and thus, they produce a solution of separate gel bundles that are almost spherical particles with sizes in the range of nanometers of 50 to 150 nm (Castro et al. 2013). These gels can flow under differential pressures that are greater than their transition pressures, as was experimentally demonstrated by Mack and Smith (1994).

Application of CDGs is limited to injection wells and involves injection of large volumes that are comparable to those of polymer flooding and are expressed in terms of pore volumes as well. Sweep efficiency improvement is achieved by providing in-depth fluid diversion due to deep gel penetration and weak strength that result in complete or partial blocking of high-conductive zones. Mack and Smith (1997) mentioned that based on field results, CDGs work by flooding preferred water flow paths between injectors and producers once-through, they restrict the flow to preferential water paths and force it to tighter rocks. This conformance technology has been widely applied to heterogeneous matrix-rock sandstone reservoirs produced by waterflooding with adverse mobility ratios.

Many studies have recently displayed CDGs as a feasible technology fundamentally for mobility control with additional benefits of reducing the permeability of high conductive zones (Castro et al. 2013). They have also stated that this technology is an alternative or a modified version of the polymer flooding like some other studies (Manrique and Lantz, 2011). Others have given equal importance to both functions of these agents as in-depth conformance improvement and mobility control strategy (Manrique et al. 2014). However, both groups have referred to injection of CDGs as “floods” rather than “treatments” due to the large volumes injected in the field applications. Furthermore, they have stated and validated the possibility of displacement of viscous oils by CDGs by comparing the oil responses of the first and second treatments of a retreated injection well. It is noteworthy that in this study, only CDG historic cases that involve the co-injection of the polymer and crosslinker have been considered and the early sequential gel applications were eliminated.

Weak Gels. Weak gels (WGs) are a subdivision of the bulk gel systems that have been terminologically separated to distinguish their objectives of application from those of the original technology, i.e., BGs. Essentially, these agents are low to intermediate polymer concentrations, weak strength bulk gels that can have the same or different mechanisms for improving sweep efficiency depending on how and where they are applied. In literature, several criteria have been used to characterize this gel system as illustrated by the following points:

1. In the bottle testing gel strength code system (A to J) proposed by Sydansk (1990), weak gels have Code B which refers to a highly flowing gel.
2. Han et al. (2014) have categorized a gel system as a weak gel if it has a storage modulus ($G^{'}$) less than 1 dyne/cm^2.
3. Wang et al. (2002) experimentally have showed that in order to form a weak gel, the storage modulus should be in the range of $0.1 < G^{'} < 10$ dyne/cm^2. The authors have also noted that the minimum polymer concentration required to form a weak gel is 2000 ppm, and the differences between storage modulus and the viscous modulus are relatively small.
4. Liu et al. (2010) reported that weak gels have polymer concentrations between 800-2000 ppm without further illustration about the resulted gel structure.
5. Some researchers have implied that any bulk gel system (regardless of its concentration) is a weak gel if it forms a flowing gel in the reservoir conditions under certain ranges of pressure gradients. Sheng (2011) mentioned that weak gels have a high resistance to flow but are still able to flow so can be injected deep into the reservoir. Han et al. (2014) provided similar ideas and referred to WGs and CDGs as flowing gel processes. Furthermore, Song et al. (2002) and Lu et al. (2010) pointed out that WGs are oil-displacement agents in addition to their function as blocking agents.

In this study, all reviewed weak gels history cases are Chinses oilfields where this conformance system has been extensively applied in heavy oil, unconsolidated sandstone reservoirs as an in-depth fluid diversion technology. However, only SPE history cases were included in this study due to translation issues and to avoid any bias to this conformance technology. It is important to mention that both metallic and organic crosslinking agents were used to form weak gels in these cases; however, organic crosslinkers were not used for the purposes of high temperature applications as reservoirs temperatures in most of these cases are from 109 to 163°F.

Components of Gel Technology Selection Process

This section focuses on what surveillance studies should consider for the rating and nomination of polymer gels. Furthermore, it illustrates the role of the conventional screening guidelines in this process.

In EOR science, screening criteria offer a way to test the appropriateness of the proposed recovery process for a given field. They check the compatibilities of the injected fluids with the reservoir rocks and fluids properties, where permeability, depth, temperature, oil viscosity, and oil saturation are usually included in the analyses. For EOR processes that target the microscopic displacement efficiency, the above parameters are sufficient to build an initial screening system simply because the limiting factor or the problem is the rocks and/or fluids properties themselves.

As a matter of fact, reservoir conformance problems have various roots and forms that can occur everywhere in the reservoir. Fundamentally, linking the problem to an effective solution requires taking into consideration all relevant factors that may affect the solution type, design, and performance. Polymer gels are injected in designed volumes and concentrations into the reservoir to modify rocks permeability and to divert subsequent injected drive-fluids into low permeability zones. This implies that the appropriate gel technology should be consistent with the characteristics of the conformance problem, reservoir rocks, reservoir fluids, and subsequently injected drive-fluids. This illustrates that, in addition to the parameters that have been considered for other EOR technologies, evaluations of polymer gels applicability should incorporate all parameters that depict conformance issues roots and characteristics. In this context, Shevelev et al. (2012) have pointed out that the applicability of polymer gels, polymer flooding, and colloidal dispersion gels depends on the problem, i.e., water channeling and adverse mobility, and their compatibility with given reservoir conditions like temperature, salinity, and lithology.

Unfortunately, characteristics of the reservoir conformance problems are difficult to be assessed or measured in the field with a precision. Thus, several diagnostic techniques have been used to evaluate these characteristics along with traditional geological and reservoir characterizations. As a consequence, the evaluation of these aspects has been historically performed qualitatively or subjectively using some related reservoir properties, operational and testing measurements, and engineering considerations of the conformance problems and gel technologies. Thus, for polymer gels, numeral screening studies are not able to consider all the influential characteristics of conformance problems due to the qualitative nature of their evaluations.

Based on the above considerations, it was identified that 13 quantitative parameters, 3 categorical variables, and 4 qualitative characteristics of conformance issues are required to develop an integrated selection system for conformance technologies as shown in Table 1. Furthermore, the appropriate gel technology is identified by a two steps process in order to ensure the consistency between the problem and the solution (effective linking) as shown in Figure 2. First, the four conformance problems characteristics in terms of their diagnosing parameters are incorporated in an initial selection system to match these characteristics with the conformance agents' technical specifications and mechanisms. This implies that conformance problems aspects are the elements of the gel technologies selection process. Secondly, quantitative parameters are processed in screening criteria to check compatibilities with reservoir rocks/fluids and injected fluids. The Loma Alta Sur case provides a good example for the above approach, where CDGs were selected based on the diagnosing of the problem using permeability contrast, pay zone heterogeneities, and adverse mobility ratio. Then, reservoir and fluid properties were checked using CDG screening criteria presented by Manrique et al. (2014). In this paper, only analyses of the matching (qualitative) parameters are presented due to limited space where the screening criteria can be found in work of Aldhaheri et al. (2016).

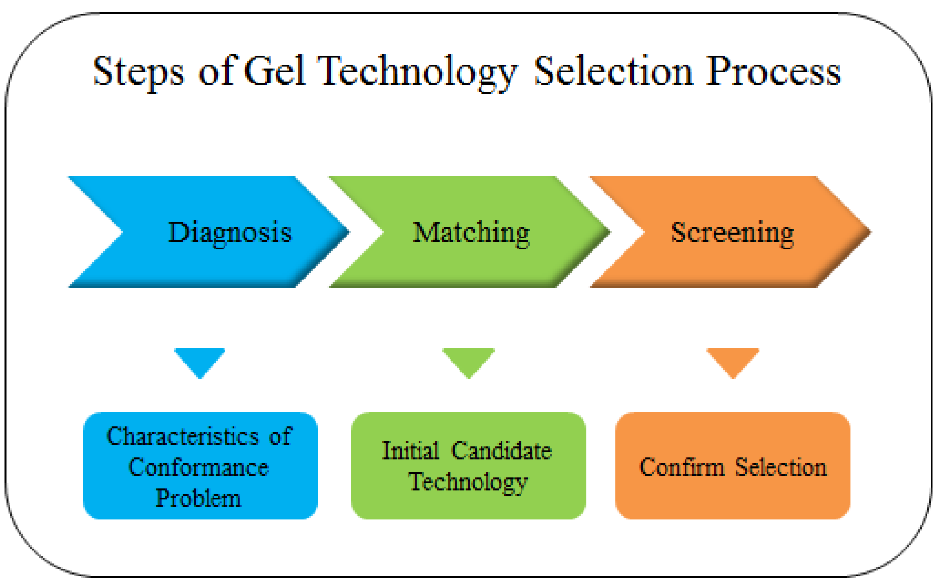

Figure 2. Components and stages required for matching conformance problems and polymer gels

Table 1. Summary of Screening and Matching Parameters Required for Selection of Polymer Gel Technologies

Quantitative Parameters	**Qualitative Parameters**
1- Reservoir Properties:	1- Drive-Fluid Channeling:
- Reservoir Lithology	- Channeling strength
- Formation type	- Channeling pattern
- Porosity	
- Formation permeability	2- Offending Zone
- Permeability variation	- Volume of channel
- Temperature	- Oil saturation
- Thickness	
- Depth	3- Conformance Problem Status
2- Fluids Properties:	- Undeveloped
- API oil gravity	- Developed
- Oil viscosity	
- Mobility ratio	4- Existence of Crossflow
- Water salinity	
- Oil saturation	5- Solution Type
3- Operational Aspects:	- Gel-volume dependent
- IOR process	- Gel-strength dependent
- Water cut	
- Recovery factor	

Review of Gel Field Projects

This section explains how polymer gels were selected on the light of their field applications in injection well patterns. A specialized database was built using the case histories published in SPE papers and U.S. Department of Energy reports from 1978 to

2015. Currently, the database includes 111 gel field trials and 50 parameters that include reservoir and fluids properties, diagnosis results, treatment operating parameters, and performance indicators.

For most case histories, the choice of polymer gels was apparently made according to Sydansk's and Southwell's rule of thumb even if it was not mentioned (Al-Dhafeeri et al. 2005; Norman et al. 2006; Muruaga et al. 2008; Diaz et al. 2008). This indicates that the selection of polymer gels was exclusively based only on one characteristic of the conformance problems that is drive-fluid channeling strength. In addition, this characteristic was qualitatively described mainly using the problem type in terms of reservoir lithology and formation type. Furthermore, it was indicated that other influential characteristics suffer from the lack of evaluation and they were reported (few cases) for purposes other than the selection of the treating agent. For example, volumes of problem zones were evaluated in few gel projects (17) and were used in design of the required gelant volumes. Moreover, these problem characteristics were mostly qualitatively described such as large or small problem zones volumes or there is quantifiable mobile oil saturation in place. More observations about the reviewed field projects will be illustrated in the last sections after the discussion of other selection parameters.

In contrast, Chou et al. (1994) and Love et al. (1998) exceptionally utilized quantitative screening criteria to identify the problematic injectors in the case of the Eunice Monument South Unit (EMSU). They assessed the degree of communication between an injector and its offset producers by the correlation coefficient of water injection and production rates. Then, the problem wells were ranked according to the estimated correlation coefficients and the injectors with > 0.5 coefficients were selected for bulk gel treatments. They have pointed out that the highly correlated wells generally have positive responses after gel treatments, and vice versa.

In this project review, it was indicated that the following 13 different reservoir, operational, and diagnosing indicators were utilized in the characterization of drive-fluid communication:

1. Conformance problem type such as naturally fractures network, wormholes, multi-layer reservoir, and high permeable channel
2. Reservoir lithology and formation type
3. Reservoir permeabilities (maximum, average, and minimum)
4. Offending zone permeability
5. Permeability variation parameters (Dykstra-Parsons coefficient (DPc) and permeability contrast)
6. Mobility ratio of oil and injected fluids
7. Flow regimes
8. Drive-fluid injectivity (vacuum injection pressure)
9. Water cut increasing rate
10. Injection profiles
11. Breakthrough time of injection water
12. Chemical tracers breakthrough time and number of broke through producers
13. Producer-injector correlations in term of water injection and production rates or pressures

Some of the above indicators will be discussed in the comparative analyses section. It is important to note that some of the aforementioned channeling indicators are numerical measures; however, they were not sufficient to establish distinctive application intervals for gel technologies. It was indicated that the diagnostic tests that produce numerical evaluations suffer from three problems especially data availability. Some channeling indicators have large number of the data points, but they are insufficient to describe drive-fluid channeling. Other indicators such as drive-fluid injectivity or thief zone permeability are direct; however, they were evaluated in few cases or they were qualitatively evaluated.

To sum up, in the overwhelming majority of field trials, conformance problems characterization was performed qualitatively, concentrated on the drive-fluid channeling strength, and the choice of gel technologies was solely based on this aspect. Furthermore, qualitative descriptions such as formation or problem types have been utilized for the evaluation of drive-fluid channeling despite the availability of some diagnosing results. Although there are numerical indicators, drive-fluid channeling was not clear and not comparable for different situations because these indicators were either used qualitatively, not evaluated, or they have indirect relation to the drive-fluid channeling.

New Classification of Conformance Problems

The nomination of the suitable conformance technology involves interpretations of the water production problems that have an inherent degree of uncertainty regarding some of their aspects. Therefore, the classification of these problems would enhance the comparisons between different problem types and improve the selection process.

Historically, conformance problems have been categorized with respect to many aspects such as problems roots, location relative to wellbore, permeability heterogeneity direction, presence of crossflow, and the flow system whether it fractured or matrix-rock reservoir.

In this study, conformance issues were classified according to four aspects as illustrated in Table 2 in order to compile the whole picture of the problems and their corresponding solutions. Most importantly, to be able to compare these aspects for different situations or conditions and establish distinctive applicability ranges for the treating technologies. It is important to note that this classification framework was established based on the comprehensive comparative analyses presented in next section; however, for better understanding, it is presented separately and in advance.

Communication Strength and Pattern. The overwhelming majority of polymer gel studies have emphasized that the drive-fluid channeling strength is a key parameter in the selection of the conformance agent is if it is compatible with reservoir and fluids properties (Sydansk and Southwell, 2000; Baker et al. 2012).

Direct Channeling Problems. This type of conformance problems refers to what just their name implies, a strong or sever communication of drive-fluid between the injector and the producer. More precisely, water channeling is strong if the water production rate of the producer strongly follows the water injection rate at the injection well (Baker et al. 2012) as it is shown in Figure 3.

This problem type is encountered when the injection fluid flows in high conductive reservoir features directly from injection well to producer well and extremely rapid breakthrough is expected even for viscous-fluids like polymers not only the conventional drive-fluids and tracers. These features may include naturally/hydraulically fractured formations, high permeability streaks, vugy porosity, conduit channels, solution channels, and wormholes due to sand production.

Table 2. Generalized Classification Framework for the Injection Well Reservoir-Related Conformance Problems and Their Associated Symptoms

Property	Conformance Problem Types	
Degree of Communication Strength	Indirect-Channeling Weak to moderate connectivity < 0.5	Direct-Channeling Moderate to strong connectivity > 0.5
Communication Pattern	Bounded Limited areal extension offending zones Small problem zones	Extensive Lateral extended offending zones Large problem zones
Problem Current Development Status	Undeveloped Early in flooding life Low Water cut High Oil Saturation Water cut increases after the remedy Improving oil sweep efficiency	Developed Late in flooding life High Water cut High/Low Sox Water cut decreases after the remedy Reduce excessive fluid production
Required Solution Type	Gel-Volume Dependent Far-wellbore Flooding Size	Gel-Strength Dependent Far/Near-wellbore Treatment Size

Sox = remaining oil saturation

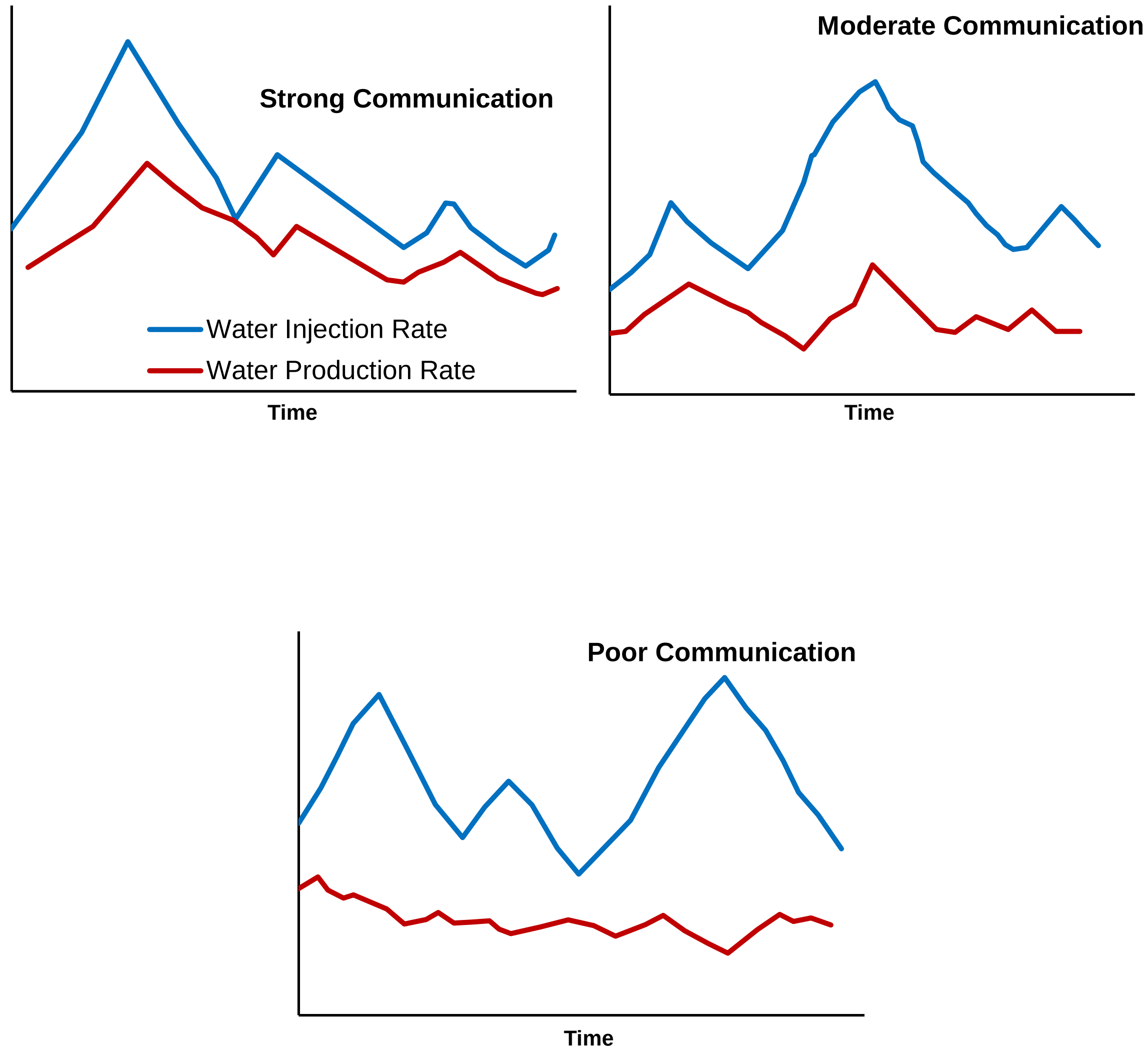

Figure 3. Typical association trends of water injection and production rates for different channeling strengths (Baker et al. 2012)

Some studies have referred to the aforementioned characteristics as high permeability anomalies (Sydansk and Southwell, 2000), fracture-like features, short circuits (Portwood et al. 2010), or they have used the “fracture-dominated flow” term to specify drive-fluid flow in these zones (Wassmuth et al. 2005; Lantz and Muniz, 2014).

Indirect Channeling Problems. When the conformance problems involve poor communication of the injected fluid between the injection and production wells, they rank as indirect channeling problems. Practically, such problems are identified when the general trend of water production rate of the producer is different from the injector rate behavior (i.e. uncorrelated wells). This problem type denotes to the flow of the injected fluid in low permeability reservoir feature; however; higher than permeabilities of the adjusting zones. Some studies have utilized the "matrix-dominated flow" term to describe the flow of the injected fluid in such zones.

Concerning communication pattern, conformance issues are classified according to the volume of the problem zones into small and large. It is important to note that the existence of crossflow and presence of high oil saturations in the offending zone plays a vital in determining communication pattern of a given situation as illustrated in next sections.

Conformance Problem Status. In this sense, conformance problems are classified according to their development status based on the drive-fluid channeling whether it has not, partially, or completely expanded through the problematic zones of the reservoir. Some researchers have referred to this problem characteristic as "flood maturity" (Manrique et al. 2014; Li et al. 2014) or zonal processing (Love et al. 1998). Some studies have classified the remediation of conformance problems based on their status into proactive and reactive treatments (Soliman et al. 2000).

Undeveloped Conformance Problems. If the channeling-incitation zones are not or partially swept with the drive-fluid, then a conformance issue is an undeveloped problem. This situation can be encountered in immature oilfield at early stages of flood life (new floods); the matter that implies that water production has not reached serious levels at offset producers. However, initial project assessments show serious channeling indicators as the field matures due to viscous fingering or permeability variation. This implies that the conformance issue is an oil recovery sweep efficiency problem (not excessive water production) and conformance remedies are applied in these cases in order to obtain an improved flooding.

In case of low concentration polymer gels, the objective of remediation in the case of the undeveloped problems is to displace oil by an improved flooding that has better injection profiles than other drive-fluids like water. This would leads to delay or mitigate channeling of the drive-fluid (breakthrough and production) in the offending zone, the matter that allows a higher hydrocarbon production at a considerably economic cost. This type of problems is characterized by low water cuts, high oil saturation in all zones (swept and unswept if flood started already), and increasing post-treatment water cuts. Recently, Kuiqian et al. (2015) have pointed out that for the early stage gel treatments, the characteristics of the responses on the producers were different from those in high water cut gel treatments. They indicated that water production continues to increase after the conformance control; however, it is lower than reservoir simulation predictions.

Developed Conformance Problems. Normally at the late stages of the flood life in mature oilfields, the high-capacity zones are completely swept by the drive-fluid and they have already caused the communication between the injector and producer. In this context, Love et al. (1988) have referred to the zones that had more than 100% of the hydrocarbon pore volume swept by water as over-processed zones. This type of problems is marked by high water cuts, low oil saturations in the channeling zones, and decreasing post-treatment water cuts. This indicates that the conformance issue is an excessive water production problem and conformance remedies are applied to improve the injection fluid profiles. For this problem type, offending zones may have high or quantifiable remaining oil saturations due to the adverse mobility ratios or permeability microscopic heterogeneities within the problematic zones themselves.

Comprehensive Comparative Analysis of Conformance Problem Characteristics

In this section, gel technologies are compared with each other in term of the characteristics of conformance problems treated by these systems. The ultimate goal is to identify the influential parameters in the identification process and their corresponding values for each gel technology. In this study, the comparisons were performed on the basis of the conformance engineering considerations, technical specifications of polymer gels, and field experiences summarized in this project review. In the next sections, the identified parameters and their differences among gel technologies will be presented and briefly discussed.

Drive-Fluid Channeling Strength. Because of the absence of a rigorous characterization system and a distinct measuring scale, this aspect has been subjectively evaluated using 13 different reservoir properties, operational parameters, and diagnosis indicators in the reviewed projects. Some researchers provided general discriminating cut-offs, ranges, and categories for some channeling indicators based on their extensive field experiences as shown in Table 3. For example, Baker et al. (2014) attributed the utilization of bulk gels for fractures or small volume streaks if their permeabilities are fifty times greater than matrix rock permeability in referring to severe drive-fluid channeling.

Data availability greatly affected the comparisons of gel technologies with respect to the 13 channeling strength indicators mentioned in the gel project review section. While there is a reasonable amount of data for reservoir properties, few case histories provided information for the diagnosis and operational indicators like tracer break through times (14) and drive-fluid injectivity (12). In many instances, the desired indicators were qualitatively described like high injectivity, poor injection profiles, and rapid water breakthrough. Comparatively, few indicators were identified as distinctive aspects such as reservoir lithology (carbonate), problem type (wormholes), and water flow rates correlations (> 0.5). However, most indicators are shared between different gel systems and sometimes they are intersected or overlapped over wide ranges as shown in Figure 4 and Figure 5 for permeability and chemical tracer breakthrough time.

It is important to note that except the correlational analyses, none of these aspects can individually provide a comprehensive evaluation of the drive-fluid channeling, and this evaluation requires the employment of all available relevant information in a complementary manner. The comparisons are not presented in this paper due to the limited space and the lengthy accompanied discussions. We plan to summarize these analyses in a separate publication.

From reservoir engineering considerations, it is thought that each lithology/formation type has a distinct "signature" on the drive-fluid channeling. It is expected that channeling is more severe in fractured and unconsolidated formations than in matrix rocks reservoirs; however, this is a highly general statement. Current projects

Table 3. Some Proposed Cut-offs for Diagnosis Parameters of Drive-fluid Channeling Strength

Parameter	Weak Channeling	Strong Channeling	References
Problem Zone Permeability	< 2000 md	> 2000 md	Sydansk & Southwell (2000)
	<10 Darcies	> 10 Darcies	Sydansk (2007)
Permeability Contrast	$K_{Streak} > (2\text{-}10)\ K_{Matrix}$	$K_{Streak} > (50)\ K_{Matrix}$	Baker et al. (2012)
	$K_{high} < 1000\ K_{Matrix}$	$K_{high} > 1000\ K_{Matrix}$	Sydansk (2007)
Permeability Variation	DPc > 0.6	-	Reynolds and Kiker (2003)
	0.55 < DPc < 0.7	DPc > 0.7	Castro et al. (2013)
Drive-fluid Injectivity	< 10 bpd/psi	> 20 bpd/psi	Pipes & Schoeling (2014)
	-	> 5 Expected [1]	Tweidt et al. (1997)
Recovery factor	-	< 33 %	Montoya Moreno et al. (2014)
Flow Regime	Radial	Linear	Sydansk (2007)
Interwell Communication[2]	< 0.5	> 0.5	Baker et al. (2012)
Formation Type	-	Naturally Fractured Unconsolidated	Current Study
Drive-fluid Breakthrough Time	Months to years	Weeks to Months	Current study
Tracer breakthrough Time	Weeks to Months	Hours to Days	Current study
Water Cut Increment Rate	< 0.5 per year	> 0.5 per year	Current Study

(1) Based on average reservoir parameters, (2) correlation coefficient of producer-injector pressures or flow rates.

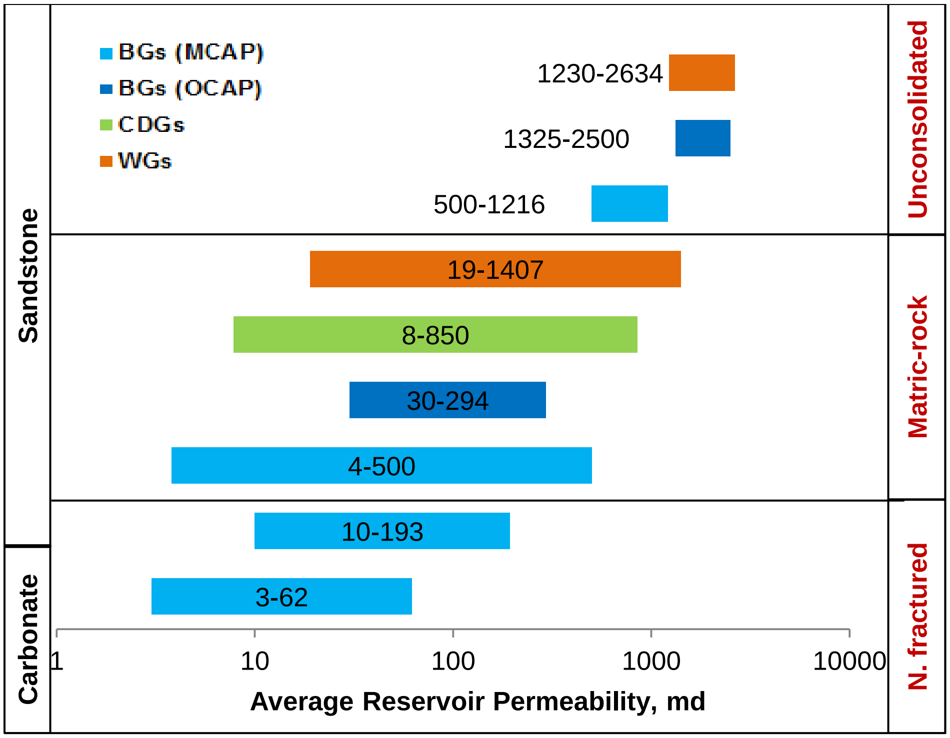

Figure 4. Comparison of the average permeability applicability ranges for different gel technologies

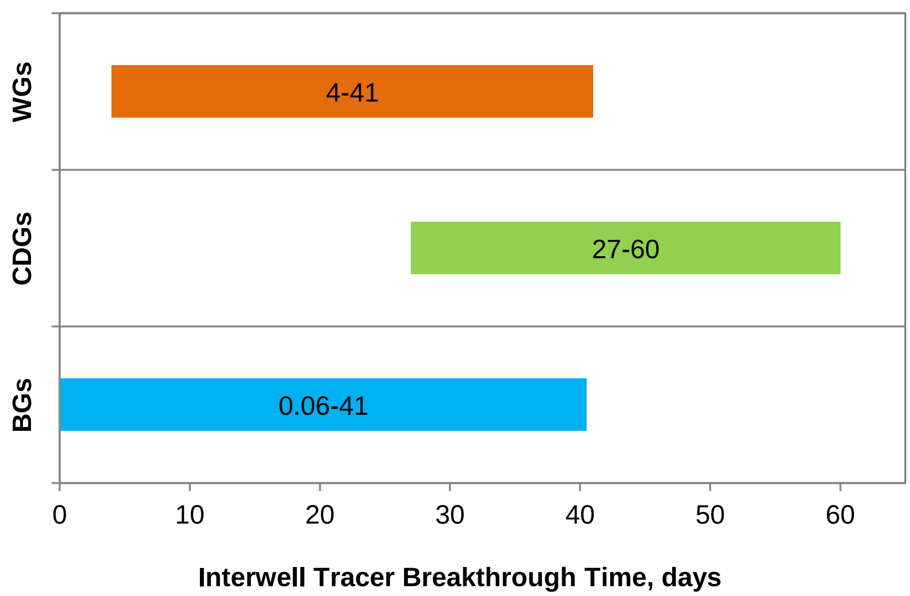

Figure 5. Comparison of interwell tracer breakthrough times in gel project summary

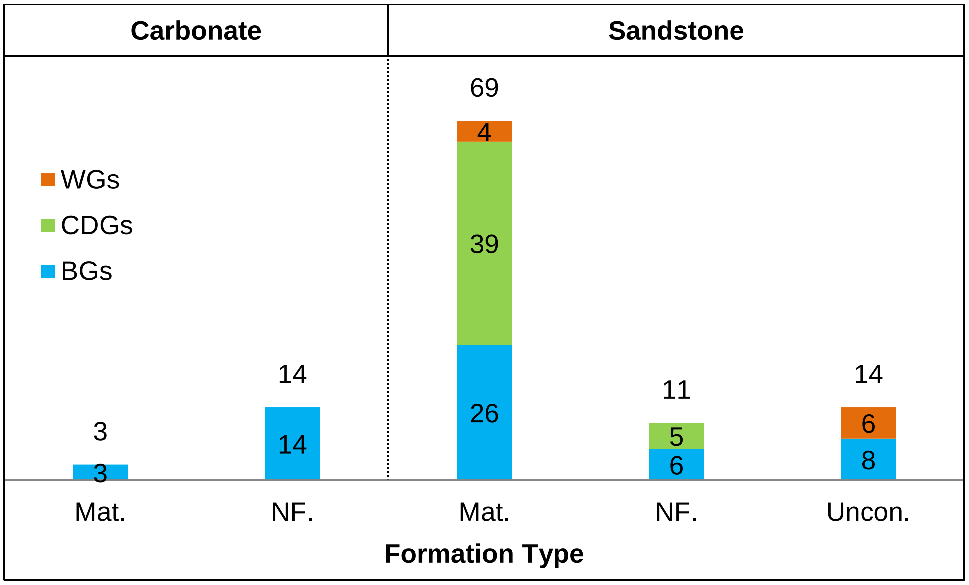

Figure 6. Distributions of polymer gel projects according to reservoir type

review illustrates that BGs were applied in matrix rock reservoirs more than in naturally fractured systems (29 vs. 20) as shown in Figure 6. Figure 4 shows that CDGs and WGs were applied in matrix rock reservoirs that have higher average permeabilities than BG matrix rock trials. Thus, if it is stated that BG matrix rock case histories have high permeability anomalies, the above observation would imply that CDG projects have higher permeability anomalies than BGs under the assumption of correlating average and high permeability values for the reviewed reservoirs.

The ICP (Colombian Petroleum Institute) proposed a gel selection methodology in which Dykstra-Parsons coefficient (DPc) has been introduced as a key parameter to guide the process (Castro et al. 2013; Maya et al. 2014). This rule suggests the application of CDGs if $0.55 < DPc < 0.7$ and the application of BGs for reservoirs with DPc values > 0.7. Figure 7 shows that DPc application intervals for polymer gels are intersected over wide intervals and a large number of CDG treatments were applied in formations with DPc > 0.7. This indicates a clear conflict with ICP criteria that have preserved this range (> 0.7) for bulk gel applications; thus, these criteria are only regional-decision-making rule.

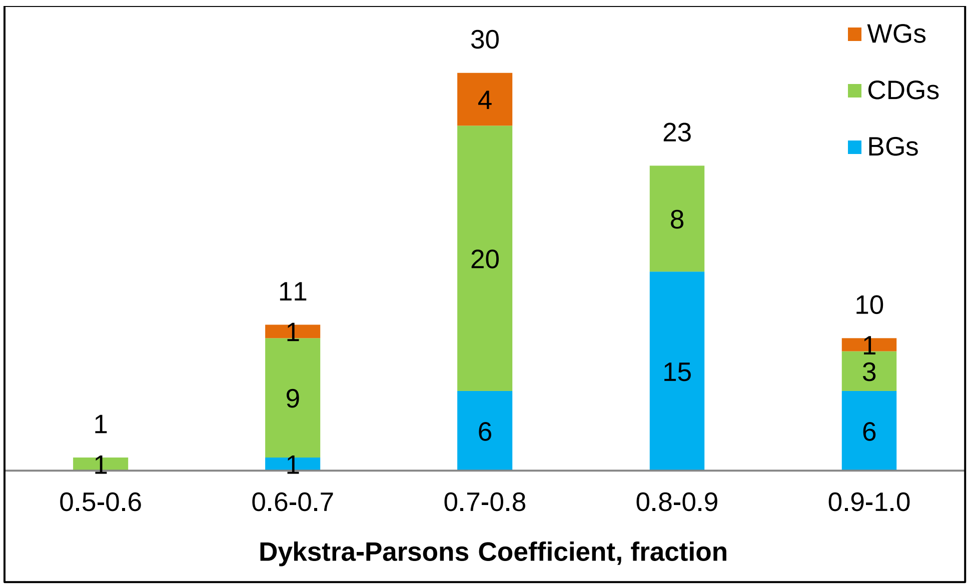

Figure 7. Permeability variation coefficient distributions for polymer gel projects

The above observations point out that the aforementioned channeling strength-based gel selection statements that employ formation type or permeability variation are inadequate to describe the degree of the interwell connectivity and they cannot provide an efficient selection system for chemical agents particularly for sandstone formations. It can be easily recognized that CDGs and WGs were applied in moderate to strong channeling conditions that are good candidates for BGs based on the above statements. If that is true, it then implies that there are many objectives for the gel treatment and the selection of a conformance agent does not depend solely on the severity of the drive-fluid channeling.

On the basis of the reviewed indicators and technical specifications of polymer gels, we inferred the channeling strength ranges shown in Figure 8 for the gel technologies under evaluation. In this figure, four severity intervals were assigned to the channeling strength, where for each interval there are at least two applicable chemical systems. The interferences or overlaps in the channeling strength ranges of gel systems are explained by the intersections over wide intervals of all reviewed indicators (lithologies, formations, permeability, DPc, tracer breakthrough time, etc.) as mentioned earlier.

Generally, the proposed extents are consistent with the previous studies (Sydansk and Southwell, 2000; Smith and Larson, 1997) that BGs and CDGs are applied in strong and weak fluid communications, respectively. However, the extension of BG and CDG ranges over the weak and strong regions would need consolidated justifications that are illustrated in the following paragraph.

Additionally, comparisons of the mispredicted projects by the main logistic models and by their variants (with no water cut) illustrate some important points. First, the low water cut (early stages) CDG projects were probably applied in moderate to strong channeling strength extents; therefore, they were mispredicted as BGs. These comparisons also showed that high water cut BG projects had probably weak to moderate channeling strengths at early stages, and thus, they were misclassified as CDGs. However, these strengths were exacerbated by the long time water injection to enter into the strong regions and justify the utilization of bulk gels at late stages. These two observations indicate the importance of knowing the problem development status and treatment timing in the selection of polymer gels. It is important to mention that BGs and CDGs were mainly applied and high and low water cuts, respectively.

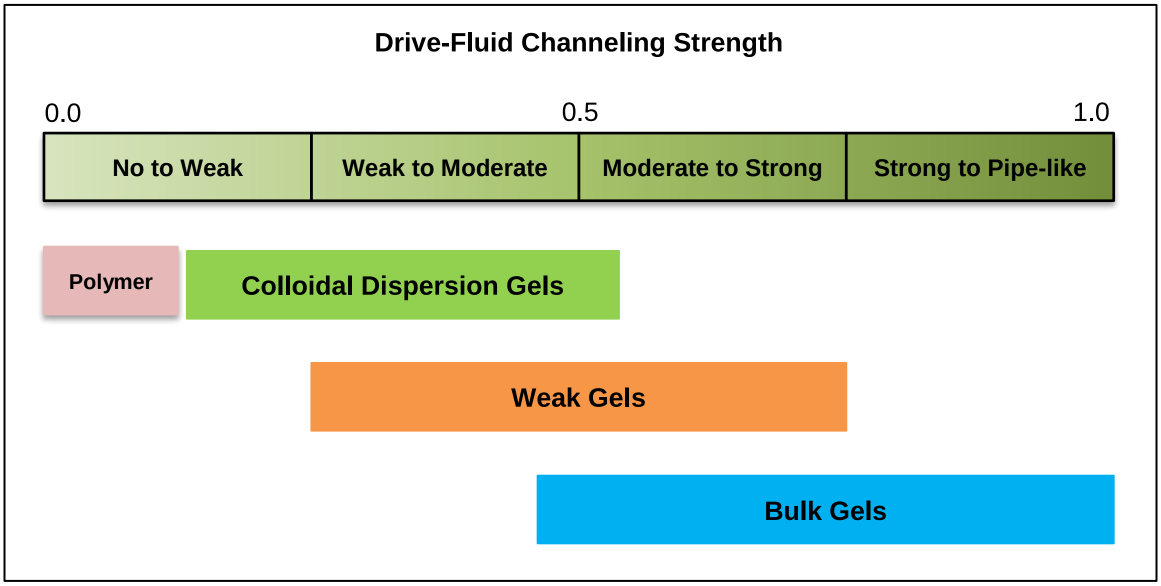

Figure 8. Drive-fluid Channeling Strength Applicability Ranges of Polymer Gels

Problem Zone Volume. Generally, this criterion has been implicitly considered in the previous gel applicability evaluation studies and only to explain the impacts of the crossflow on the type of the required treating agent. For injection wells, bulk gels are typically applied in moderate volume treatments ranging from 300 to 60000 bbl. based on the summarized field trials. CDG and WG treatments involve injection of large volumes that are usually in a scale of several 100,000 barrels (Sydansk and Romero-Zeron, 2011). For the reviewed CDG and WG case histories, the injected volumes are in the ranges of 4200-117000 bbl. and 12600-505000 bbl., respectively. This implies that BGs are used to restrict water flow into small problem zones while CDGs and WGs target large problem zones that are in reservoir scale. However, this quiet general statement does not help in the rating of the treating agents for a particular problem zone. Thus, establishing statistics for the problem zone volume aspect that can tell us how small or big are these zones are of extreme importance.

In this project summary, moveable-pore-volumes (MPV) were estimated only for BG projects despite the existence of different evaluation techniques. Out of 50 bulk gel field trials, only 17 case histories reported evaluations for this characteristic that were estimated using the production plots (WOR versus NP). The MPV statistics shown in Figure 9-a illustrate that BGs were applied over a wide range from 30 to 1036000 bbl. with a median of 80000 bbl. and about 82% of projects are in a range of 10000-600000 bbl. It is clear that with this small amount of data it is not possible to perform comparative analyses for all considered conformance control agents.

In an effort to make the comparative analyses possible, problem zone volumes for bulk gel projects were estimated using the widely used gelant volume design rule of thumb and the actually injected gel volumes. In the gel treatment design stage, gelant volumes are evaluated as a percent of the estimated MPV and usually this percent is from 5 to 50 % (Smith, 1999). In this study, the injected volumes have been considered to represent 5% of the MPV in a conservative approach to calculate the problem zone volumes. Figure 9-b presents estimated problem zone volume distributions and Table 4 compares them in terms of different statistical parameters with the reported values discussed above. Interestingly, both volume values provide approximately identical statistical attributes where projects frequencies are distributed almost over the same range

6000-1,200,000 bbl. with a median of 120000 bbl. and about 84 % of projects are in a range of 10000-500000 bbl. In other words, they have the same statistical central and variation tendencies.

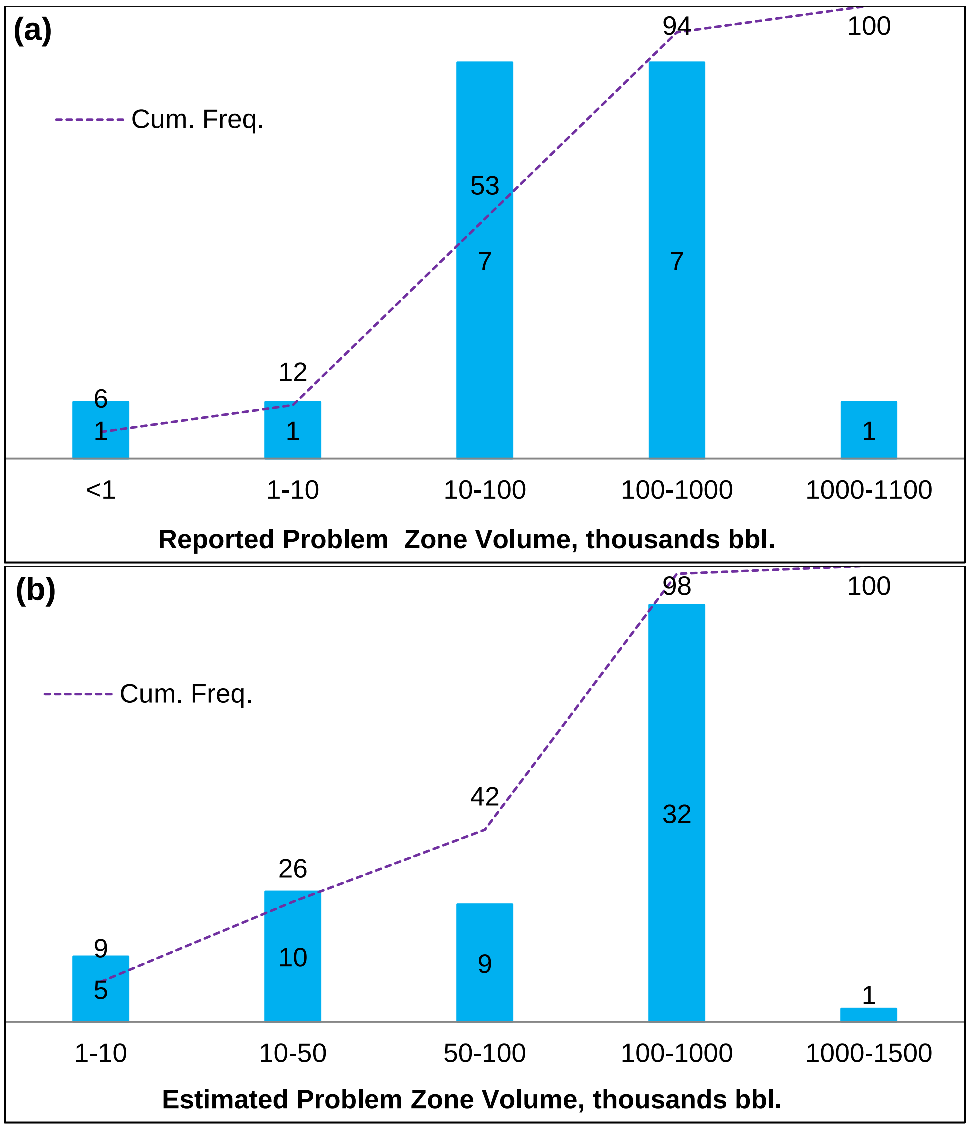

Figure 9. Distributions of (a) reported and (b) estimated problem zone volumes for bulk gel projects

Table 4. Statistical Comparison of the Reported and the Estimated Problem Zone Volumes for Bulk Gel Projects

Property	Problem Zone Volume, bbl.	
	Reported	Estimated
Points Count	17	57
Mean	201831	196747
Median	80000	119960
St. Deviation	266774	233202
Coff. of Variation	1.3	1.2
Minimum	30	6000
Maximum	1036000	1200000

As mentioned above, no problem zone volume estimations were provided for CDG and WG projects. Therefore, the injection pattern pore volumes were estimated using the injected gel volumes as they provided in barrels and pore volumes. Then, the offending zone volumes were considered to represent 50% of the pore volumes by assuming that the reservoir consists only of two equal thickness layers as illustrated in Figure 10. The distributions of the estimated volumes for CDG projects presented in Figure 11 illustrate that these polymer gels were applied over a broad range from 10^6 to 500 x 10^6 bbl. with a median of 3358867 bbl., and about 97 % of projects were applied in problem zone volumes less than 50 x 10^6 bbl.

For the three gel systems of interest, the estimated problem zone volumes were summarized in Table 5 and compared in Figure 12. These analyses show that each gel technology was applied in a wide range of problem zone volumes and this range is almost separated from those of the other gel systems. The problem zone volume ranges of gel systems appear as one completes the other to cover the whole application ranges.

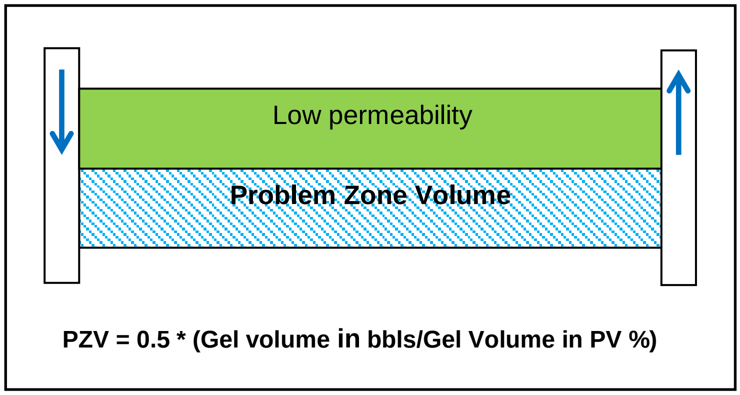

Figure 10. Estimation of problem zone volume in case of flood-size gel treatments

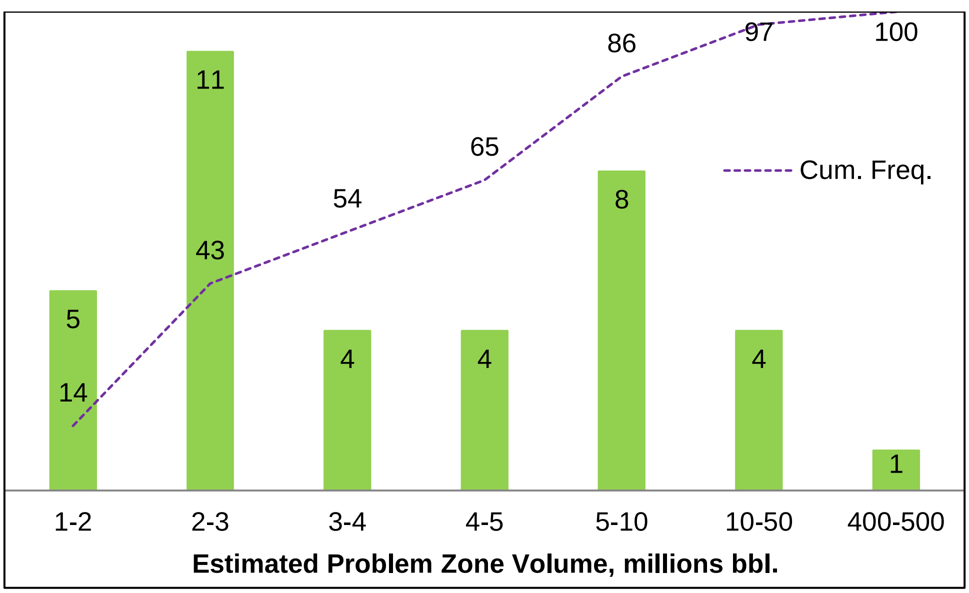

Figure 11. Distributions of the estimated problem zone volume for CDG projects

Table 5. Descriptive Summary of Problem Zone Volume Estimations in Gel Projects

Property/Gel Type	Problem Zone Volume, bbl.		
	BGs	CDGs	WGs
Points Count	57	37	3
Mean	196747	1.90E+07	1.69E+09
Median	119960	3200000	1181425750
St. Dev	233202	80334313	1649409798
CV	1.2	4.2	1.0
Minimum	6000	1.05E+06	3.57E+08
Maximum	1.20E+06	4.93E+08	3.54E+09

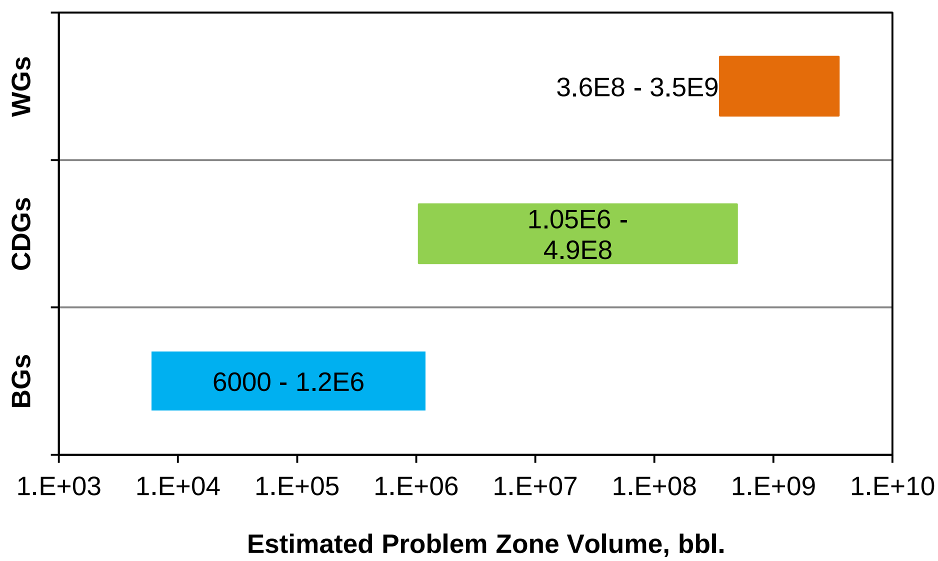

Figure 12. Comparison of the estimated problem zone volumes in gel field projects

However, it is important to note that WGs have only 3 estimations for this aspect. In this study, a one million barrel problem zone volume has been considered as a cut-off to distinguish between the problems that are treated by the treatment-size systems and the flood-size gel technologies. This cut-off is consistent with the largest estimated MPV for BG projects that is 1036000 bbl. in the Raven Creek field (Smith, 1999). It is important to mention that this characteristic of conformance issues is affected by two considerations as it will illustrate in the next sections.

Problem Development Status. In this study, reservoir conformance problems have generally been classified based on their development status and some associated symptoms were explained as well. To illustrate this problem characteristic in the summarized field applications, the pre-treatment water cut and the time-lapse between the recovery flood initiation and the gel treatment implementation were employed.

Figure 13-a illustrates that 66% of CDG projects were applied to treat undeveloped problems at water cuts less than 50% and 15 treatments were implemented at the very beginning of the flood life, i.e. water-free production. Although CDG projects are distributed over the whole water cut ranges 0-96%, this data set has a median of 0.002% as shown in Table 6. Project frequencies are concentrated at the 0-10% and 90-100% intervals where 58 % and 19 % of projects are in these ranges, respectively. This indicates that CDGs are applied for both problem types with a clear tendency towards undeveloped problems and there is a recent interest in testing this technology in very developed problems (Diaz et al. 2008).

For weak gels, Figure 13-b shows that 60% of their trials treated well developed problems with high water cuts 80-100%, and only 20% of their applications are at water cuts less than 50%. This data set has a median of 71% and only one history case was treated at very early times with zero water cut. This indicates that WGs were applied for both problems types, but mainly in developed circumstances. In contrast, BGs were applied only for the developed conformance problems and considerably for very high water cuts situations where 79% of the trials are in 80-100% as shown by Figure 13-c. Table 6 shows that these projects have a median of 93.5 % and very homogeneous data with a coefficient of variation of 0.15. This indicates that the primary concern for BGs projects was reducing water production rates by blocking the high conductive zones.

The project distributions and the descriptive summary of the treatment time-lapse confirm the preceding observations as shown in Figure 14 and Table 7. CDGs were frequently applied at early times where 74 % of projects were performed in less than 5 years after the flood initiation, 10 projects were performed in the same year, and few field cases were treated after more than 5 years. The median (2 years) clearly signalizes the early application tendency of this gel system. Weak gels have the narrowest time lapse distribution among gel systems, 60% of their trials were performed after 5 years, the median is 6.5 years, and only one treatment in the same year of flood inception. Bulk gel trials are distributed over the whole time range; however, this data set has a high median of 13 and about 80% of projects were carried out after 5 years. This obviously implies the late time application of this treating system for well-developed conformance problems.

Furthermore, the behavior or trend of water production during and after treatment was illustrated by plotting the pre and post-treatment water cuts values. The undeveloped and developed conformance problems have been characterized by having increasing and decreasing post-treatment water cuts, respectively. Figure 15 compares the pre and post-remediation water cut values for the successful projects of different polymer gel systems. For undeveloped problems (WC < 50%), it is clear that water production increases during

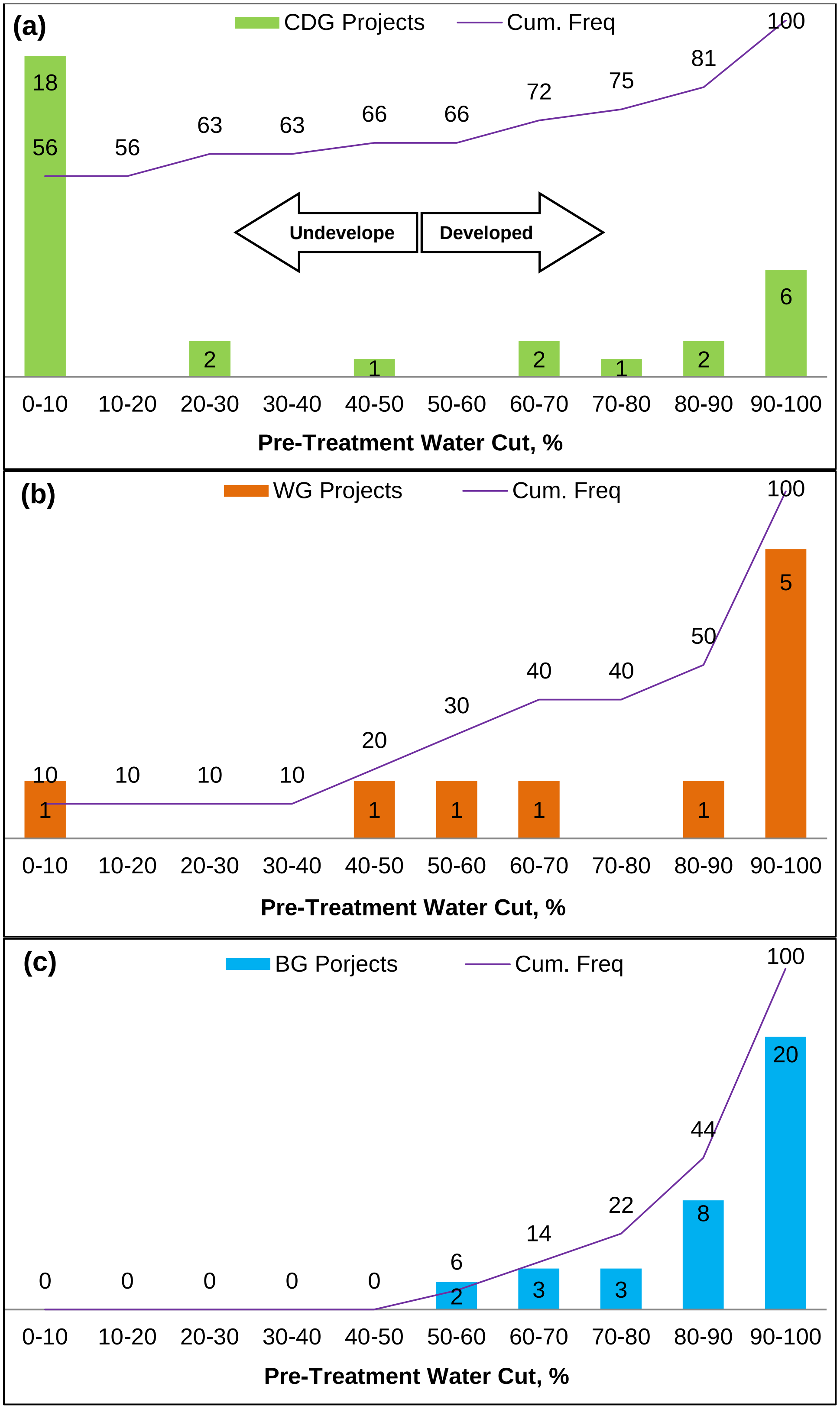

Figure 13. Comparison of the pre-treatment water cut frequencies in gel Projects

Table 6. Statistical Summary of Pre-Treatment Water Cut in Polymer Gel Projects

Property/Gel Type	Pre-treatment water cut, %		
	BGs	CDGs	WGs
Points Count	34	29	10
Mean	87.3	29	71.3
Median	91.8	0.4	87.7
St. Dev	13	38	30.9
CV	0.1	1.3	0.4
Minimum	52	0	0
Maximum	100	96	97.3
Most applied range	70-100	0-50	60-100

Table 7. Statistical Summary of Treatment Time-Lapse in Polymer Gel Project Survey

Property/Gel Type	Treatment Time-Lapse, year.		
	BGs	CDGs	WGs
Points Count	52	36	10
Mean	16.9	5.6	9.5
Median	12.5	2	6.5
St. Dev	13.8	9.4	8.0
CV	0.82	1.6	0.84
Minimum	2	0	1
Maximum	53	44	23

and after the treatment as all data points are above the unit-slope line in this figure, and uniquely CDGs and WGs were applied in this region. In contrast, water production decreases after the treatment of most developed conformance problems which their data points are below the line, and all gel systems are presented in this region. It is important to note that there are some applications that their post-treatment water cut has increased over the pre-treatment values and still considered as successful projects because the actual post-treatment water production rates are lower than the pre-treatment projections.

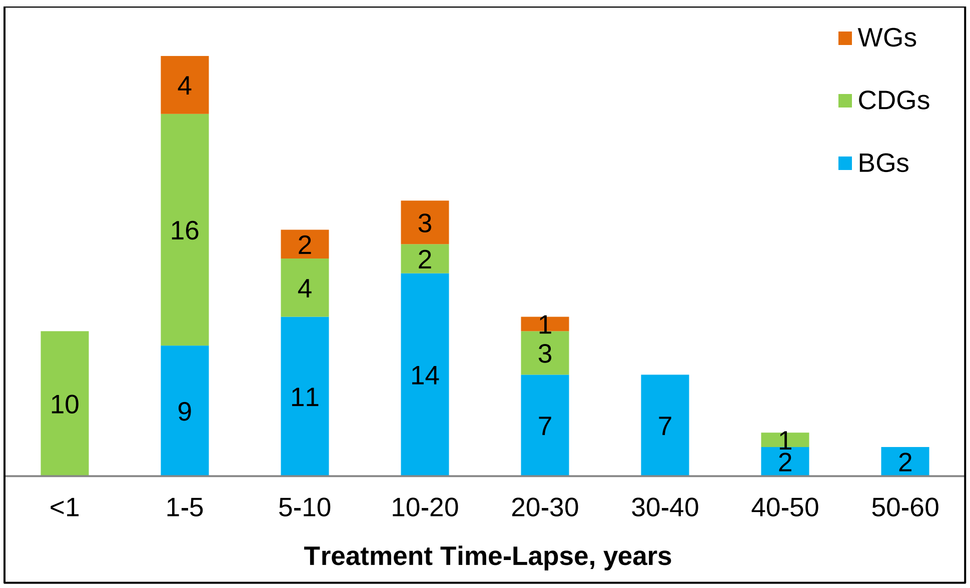

Figure 14. Treatment time-lapse distributions for polymer gel projects

In sum, BGs are applied only in high water cut patterns while other the two treating agents are employed to remedy both problem types. This would call for further investigation of the problem properties in the case of developed channeling issues as all conformance technologies are applicable.

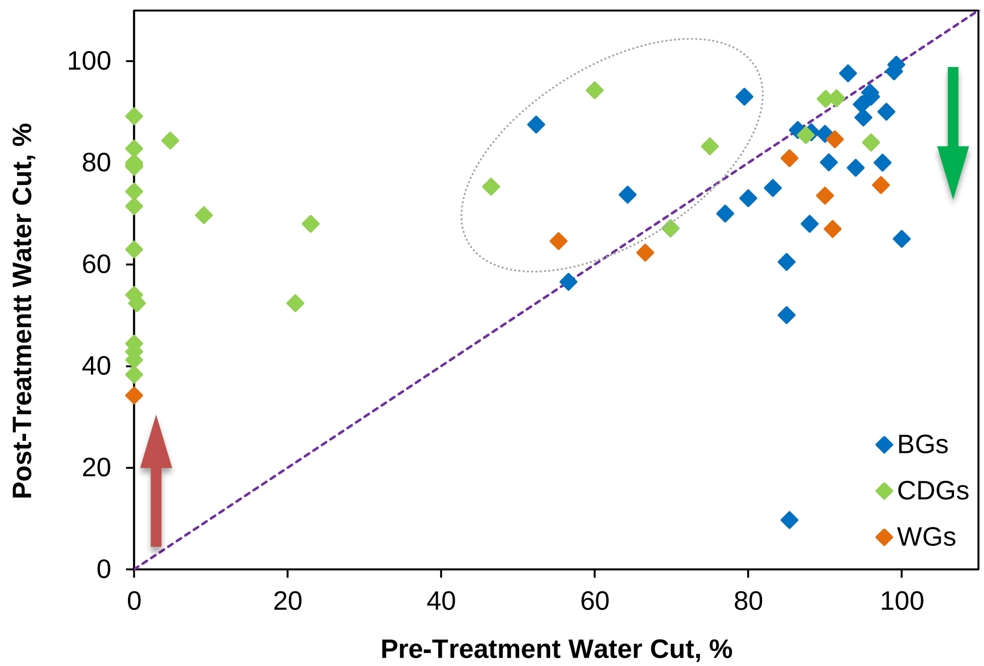

Figure 15. Scatter plot for the pre and post-treatment water cut shows trends of water production during and after conformance remediation for different gel technologies

Remaining Oil Saturation. An important issue that has been approximately mentioned in all candidate selection studies and case histories is the presence of quantifiable oil saturations in the targeted patterns. However, for gel technologies under question, no study has made a clear distinction about where these quantifiable oil saturations should be presented. In literature, researchers often used "within well pattern" or "in place" expressions in their descriptions of this fluid property. Presumably, BG studies have referred to the bypassed oil reserves in the partially-swept, low permeability zones of the treated formations. Liu et al. (2006 and 2010) listed the remaining oil distribution among the reservoir characteristics that are required to evaluate conformance control technologies.

We think that the presence of high oil saturations in low permeability zones is guaranteed by the substantial permeability contrasts that exist between different flow units of the treated formations. It is noteworthy to mention that permeability contrast ranging between 20 and 40000 for the gel projects reviewed in this study. Furthermore, taking into consideration the significant increase in oil production caused by BG treatments in some longtime flooded formations (>20 years) reveals that there were quantifiable oil saturations in the low permeability zones even after such long injection times. Seright and Liang (1994) illustrated that there are gel projects that were implemented after more than 50% of the original oil in placed had been recovered in these fields. These high permeability contrasts and oil production increments would probably confirm the above statement about the amounts of oil quantities in the less conductive layers.

There is no doubt that in the case of the undeveloped conformance problems, both offending and low permeability zones have high oil saturations simply because of the short injection times as formerly indicated by water cuts and time lapses statistics. In most cases, the implementation was almost directly after the primary production stage or after very short times of waterflooding as in case of CDG applications in the Rocky Mountain region. Diaz et al. (2008), Alvarado et al. (2008), and Lantz and North (2014) mentioned that the majority of the initial CDGs applications were applied immediately after primary production or shortly (usually one month) after waterflooding inception. In the case of Luda LD-10 field, water injection started in September, 2005 and weak gels were applied in March, 2006 that is only six months after the primary production which in turn began in January, 2005 (Lu et al. 2010; Kuiqian et al. 2015).

As illustrated before, BGs have targeted small problem zones that were flooded for long time (average 16.9 years) by several pore volumes of the injected fluids. Therefore, in these fully developed conformance problems, it is expected that at the implementation time of the remediation, these zones were completely swept and possibly at residual oil saturation. Ricks and Portwood (2000) mentioned in their justification of gel treatments in McElroy field that the highly permeable rock in this reservoir has probably been swept of secondary oil. Therefore continued cycling of water through these areas would not be effective in sweeping the tighter rock that contains the bulk of the remaining secondary reserves. Portwood et al. (2010) mentioned in the case study of Healdton field that the thief intervals were likely swept to the absolute residual oil saturation. Consequently, they used the residual oil saturation value in their volumetric calculations of the MPV of the direct flow channels. In this case history, waterflooding was initiated in 1960 while conformance treatments started in 2006.

For CDG and WG applications in developed problems, the rapid increases in oil production rates (jumps) during the agent injection time which is usually very long (years), suggest the existence of high oil saturations within the problematic zones. Muruaga et al. (2008) illustrated that a large portion of the injected gelant entered the high conductive layers in the CDG pilot in El Tordillo oilfield. This indicates that the large oil quantities produced in some case histories immediately after gel treatments were from the high conductive zones. Manrique, et al., (2014) have pointed out that such oil responses observed during the treatment would validate the possibility of CDG displacing viscous oils that previously reported by Diaz et al. (2008) and Castro et al. (2013). In addition, during their numerical simulation studies to predict CDGs performance, Diaz et al. (2015) performed a history matching for the two Loma Alta Sur staged treatments (separated by one year waterflooding) in the LAS-58 injection pattern. Their results showed that average oil saturations were 0.618 and 0.615 at the start of first and second treatments respectively. Recognizing that simulation history matching was based on the observed injection profiles and the initial oil saturation in Grupo Neuquen formation is 0.67, would confirm the presence of producible oil quantities in the high conductive zones of this reservoir.

To explain the above point, some researchers attribute the existence of quantifiable oil saturations in the offending zones to the highly unfavorable mobility and/or local heterogeneities within problematic zone themselves (Muruaga et al. 2008; Diaz et al. 2008). Others have accredited these oil responses to the ability of CDGs to improve the microscopic sweep efficiency by blocking the larger pore throats and diverting the flow to the smaller pore throats (Bjorsvik et al. 2007; Splido et al. 2009 and 2010; Rousseau et al. 2005; Cozic et al. 2009). This feature has been termed as flow microdiversion efficiency or flow diversion on pore scale by some researchers (Shi et al. 2011; Karlsen, 2010).

To sum up, the producible oil reserves by the subsequent fluid injection should be present only in the low conductive zones to ensure BG project economic feasibility. Otherwise, gel treatment will cause a delay in the oil production from the high flow capacity layers. For in-depth fluid diversion technologies, other than the existence of the crossflow, such oil saturations must present in both offending and low conductive zones. This implies that oil saturations in problematic zones is the key factor in the gel technology selection rather than oil saturations in low permeability zones that are guaranteed by high reservoir heterogeneities. Karlsen (2010) pointed out that one of the key elements to know before utilization of deep flow diversion agents is the remaining oil saturation in swept areas.

Integrated Comprehensive Selection System

According to the preceding sections, bulk gels are solutions for the problems that have the following characteristic:

1- Direct drive-fluid communication (severity > 0.5)

2- Small volume offending zones ($V_{channel} < 10^6$ bbl.)

3- Large volume problem zones that require treatment-size remedy (< 60000 bbl.)

4- Undeveloped and developed conformance problems

5- High remaining oil saturations in less capacity zones of the reservoir

6- Problems that need blockage of the high conductive zones and fluid flow diversion to the low capacity zones.

7- Problems that need gel-strength-dependent treatments

In addition, CDG gels are applicable for injection patterns characterized by:

1- Indirect drive-fluid communication (severity < 0.5)

2- Large volume offending zones ($V_{channel} > 10^6$ bbl.) that treated by flood-size remediation (> 0.1 PV)

3- High oil saturations in swept and less capacity zones (adverse mobility ratio)

4- Undeveloped and developed sweep problems

5- Oil displacement and flow diversion mechanisms are simultaneously required

6- Problems that need gel-volume-dependent treatments

Weak gels are best suited for the situations that are similar to those of BGs but with indirect channeling strengths or similar to CDG conditions but with direct channeling as they are used in two application forms or objectives depending on the type of the action required. It is important to mention that CDGs were applied in direct channeling issues instead of WGs in some case histories with naturally fractured formations.

On the basis of the proposed parameters and their variations, eight possible combinations or types for the reservoir conformance problems were indicated as shown in Table 8. For each combination of the parameters, the most suitable gel technology was identified by matching its aspects with the above technical specifications for the gel systems. It is important to note that in case of undeveloped problems, it is recommended that BGs or WGs applied only if the volumes of the offending zones are extremely small as the production from these zones might be lost or delayed by the treatment. Furthermore, for the application of CDGs for undeveloped problems; it is not necessary that these problems have adverse mobility ratios as the offending zones have high oil saturations. This situation was encountered in the case of naturally fractured sandstone formations where CDGs were applied to obtain an improved flooding in term of injection profiles.

To facilitate the ranking of the selection parameters in term of their importance in the process and to help in the visualization of the interactions among these parameters, Table 8 was reproduced in a flow chart or roadmap form as shown in Figure 16. It was identified that for small volume problematic zones, the selection is controlled only by the channeling strength.

Table 8. Eight Possible Situations for Reservoir Conformance Problems and Their Corresponding Solutions

Channeling Strength	Problem Zone Volume	Current Development Status	Crossflow Or High Sox	Remediation Size	Proposed Agent
Weak To Moderate	Small	Undeveloped	-	T	WGs *
		Developed	-	T	WGs *
	Large	Undeveloped	-	F	CDGs
		Developed	Yes/No	F/T	CDGS/WGs
Moderate To Strong	Small	Undeveloped	-	T	BGs
		Developed	-	T	BGs
	Large	Undeveloped	-	T	WGs
		Developed	Yes/No	F/T	WGs/BGs

* Weak BGs are applicable as well; Sox = remaining oil saturation; T = Treatment; F = Flooding

For large volume offending zones, the selection is also governed only by the channeling strength except in the case of developed problems with no crossflow or high oil saturation in the high conductive layers. Furthermore, the absence of crossflow or high oil saturation affects the offending zone volume and changes it (not physically) from large to small measures that can be treated by treatment-size remedies. These three observations reveal that channeling strength and offending zone volume are the main selection parameters and the effects of other aspects are translating into changes in the offending zone volume. Thus, Table 8 and Figure 16 were reduced into the simple generalized selection matrix shown in Figure 17.

One can notice that the development status aspect of the conformance issues can be eliminated as it does not affect the treating agent selection and since the crossflow and remaining oil saturation are already considered. It has been identified that this aspect dose not only provide a better understanding of the conformance issues, but also it indicates the development of the channeling strength. In addition, it illustrates the influences of this channeling strength development on the gel treatment designs as explained by following observations. Normally, the long term fluid injection exacerbates reservoir heterogeneity and makes drive-fluid channeling more and more severe with time. This observation was identified in several individual injection patters of different case histories as water injection and production rates become more following each other (Lu et al. 2010).

Figure 18 shows the water injection and production history of the Big Mac Unit starting from the initial field development stage (Lantz and North, 2014). Recall that the channeling strength is quantified by measuring how strongly injection and production rates are following each other and expressed as their correlation coefficient. One can easily recognizes the substantial progress or increase in channeling strength with the continuation of the injection process over time in this field. The undeveloped, weak channeling problem at early stages (separate curves) turned to very strong communication (matched curves) when the problem became well developed as indicated

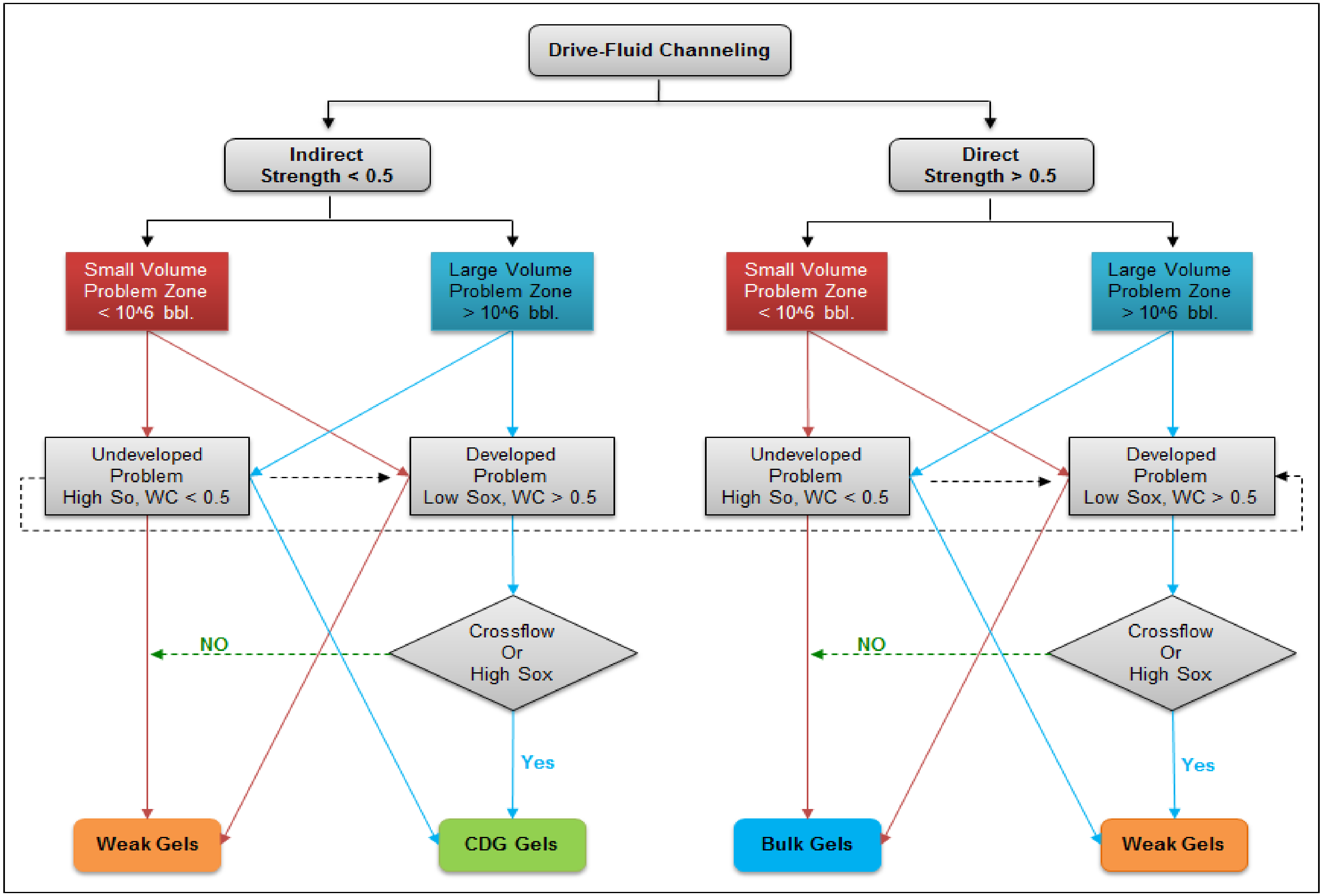

Figure 16. Integrated Roadmap for Gel Technology Selection for Injection Well Conformance Improvement

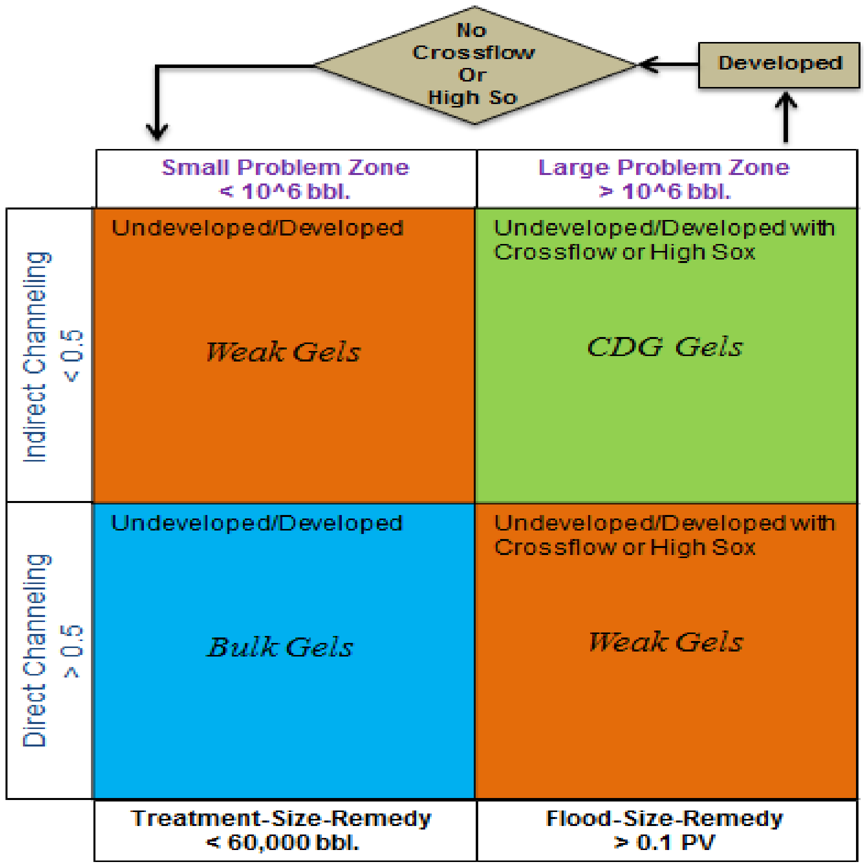

Figure 17. Generalized Polymer Gel Selection Matrix for Injection Well Conformance Improvement

by high water cut values. In this unit, the injection started in one injector and four producers; later, three producers were converted to injectors. However, since September, 1995 there are two active producers and two active injectors.

Furthermore, in the case of Little Missouri Unit, CDGs were applied in 1989 after few months of polymer flooding (undeveloped) and then in July, 2012 (developed). Interestingly, polymer concentrations were increased from 245 ppm in the first treatment to 450-600 ppm in the second treatment. This signals the effects of the development of the drive-fluid channeling strength on the gel treatment design considerations. Finally, comparisons of the mispredicted projects by the main advanced screening models and their variants (with no water cut) have indicated the development of drive-fluid channeling during the flood life (Aldhaheri et al. 2016). In one BG case history with DPc of 0.76, permeability 50 md, net thickness 10 ft, and 93% water cut, variant models predicted CDGs for this case. This implies that the initial moderate water channeling strengths exist when the problem still considered undeveloped had been exacerbated by the longer than usual water injection in this field (Smith and Larson, 1997). Afterwards, the problem had become well-developed with strong water channeling, and hence, BGs were applied to improve distribution of injection water. For this case, channel volume was estimated to be large (> 10^6 bbl) and moderate results with delayed responses were observed for the large volume gel treatment of 46700 bbl. (Smith 1999).

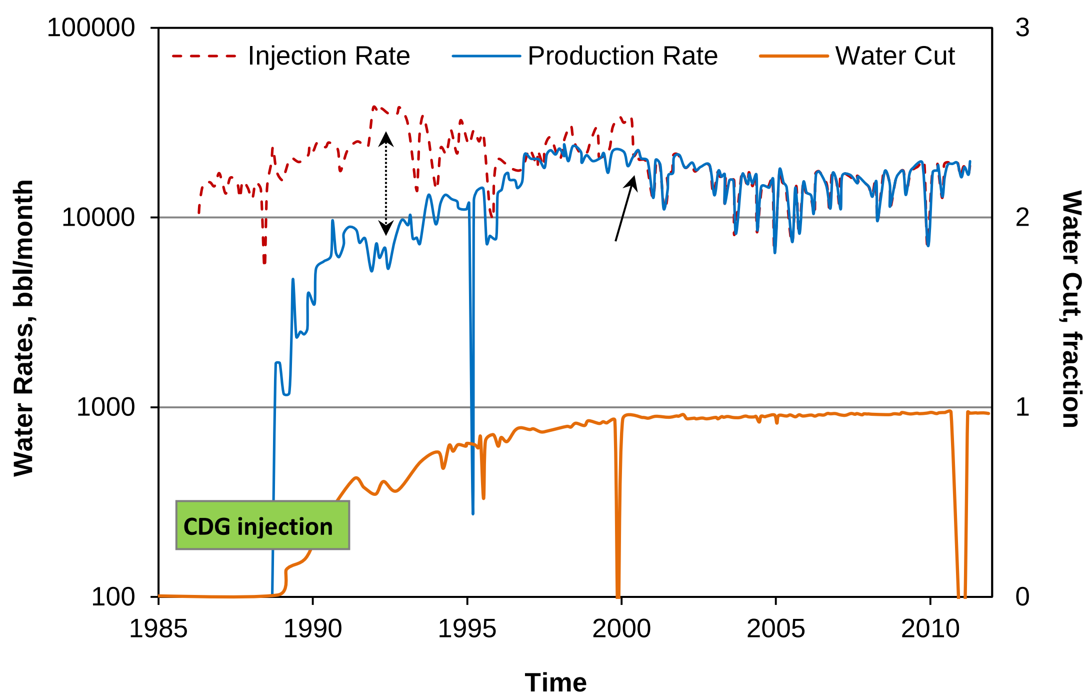

Figure 18. Water injection and production history of Big Mac Unit

Apart from the channeling strength, it was indicated that previous studies (Sydansk and Southwell, 2000; Liu et al. 2010) linked the utilization of large volume CDGs or WGs treatment in developed problems by the existence of fluid crossflow. However, only two case histories for these conformance agents mentioned this aspect (Smith and Mack, 1997; Smith et al. 2000). It is obvious that this justification involves an implicit assumption of uniform permeability and oil saturation distributions in the offending zones. Alternatively, it has been illustrated that the adverse mobility ratio and local heterogeneities within the problematic zones themselves cause a non-uniform sweeping that leads to the existence of high oil saturation unswept regions within these high conductive layers (Muruaga et al. 2008; Diaz et al. 2008; Shi et al. 2011; Karlsen 2010). The emergence of this rationalization has leaded us to conclude that the premise of the uniformity of the problematic zone characteristics is limiting reservoir engineers' imagination of the conformance problems and the analysis of the treatment implementation and performance.

The existence of a pair of gel technologies in each channeling strength region (weak vs. strong) implies that the investigated gel systems provide together an integrated solution system for the most injection well reservoir-related conformance problems. The developed selection scheme facilitates the recognition of the proper agent whether the purpose of the remediation is to improve oil sweep efficiency or to reduce water production as it considers all treating agents and selection parameters. The novelty of the proposed scheme is in its utilization of standardized general parameters for the selection which makes the process clearer and easier. It provides distinct cut-offs for conformance problems characteristics and presents technical insights about which diagnosis indicators can effectively quantify these properties. The purpose of this paper is to increase the knowledge about the criteria that should be used to select a conformance improvement technology that will help in picking the right agent and avoid making bad selection decisions. As with other (Smith 2006), we hope that the thoughts and measures presented in this study will be a catalyst for further discussion within the industry about the standardization of polymer gel selection process.

Conclusions

1. Conformance problems are often qualitatively characterized using different problem descriptions in terms of reservoir lithology and formation type. This evaluation nature has imposed several problems in the context of rating problems and solutions.
2. Gel technologies have been exclusively chosen based on the drive-fluid channeling strength and 13 different reservoir properties and operational and diagnosing indicators were utilized in the evaluation of this characteristic.
3. Particularly for clastic reservoirs, gel selection statements that employed reservoir lithology, formation type, or permeability variation are inadequate to describe the strength of the drive-fluid connectivity or to use as efficient system for chemical agent selection. They should be used only as starting point in the matching of conformance problems and gel systems.
4. Gel technology selection is a two-step process that starts by matching the qualitative properties of problems and solutions and then confirmed by the numerical screening criteria.

5. A new classification was proposed for the conformance problems to improve the comparisons between different problem and solution types and to enhance their matching process.
6. Using field implementations, a generalized comprehensive system was developed to facilitate the selection of gel technologies. The new scheme utilizes standardized parameters and provides distinguishing cut-offs for gel technologies.
7. Drive-fluid channeling, volume of offending zones, problem development status, existence of cross-flow, and nature of the required solution are the most influential aspects in the process of selection a conformance agent.
8. In addition to crossflow, the presence of high oil saturations or unswept regions in the offending zones requires the application of the flood-size treating technologies that combine displacement and diversions mechanisms.
9. The selection and design of chemical systems for a certain conformance problem greatly depend on the timing of the conformance treatment in the flood life.
10. There is an urgent need to develop an integrated numerical characterization system for drive-fluid channeling that has the ability to rate conformance problems and polymer gels. The easiness of the practical implementation is the ruling feature of any suggested methodology.

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III. An Advanced Selection Tool for the Application of In-Situ Polymer Gels for Undiagnosed Injection Wells

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Abstract

Conformance improvement by polymer gels continues to gain momentum in the field of water management in mature oilfields. A key component for a successful treatment is the identification of the most appropriate gel technology for a targeted reservoir. Advanced approaches provide efficient screening and ranking tools; however, to the best of our knowledge, no such approaches have been developed for polymer gels so far.

In this study, we utilized a machine-learning technique to develop an advanced selection methodology for the application of polymer gels in injection wells. Historical data of four in-situ gel systems including bulk gels, high temperature bulk gels, colloidal dispersion gels, and weak gels were used to train logistic regression models. Data sets of 19 property or parameter were tested for potential outliers, missing values were imputed, and some variables were categorized in order to treat data gaps. To identify the most discriminating variables, the univariate entropy R^2, stepwise regression, and area under ROC curve (AUC) heuristic technique were employed. The candidate variables were then

modified according to some considerations like the match of univariate logistic probability to conformance engineering considerations. To consider the regional tendencies in application of polymer gels, we developed three probabilistic models that include different number of treating technologies. Furthermore, to meet the new developments in the application of some gel systems, we constructed a variant model without the treatment timing indicator (water cut) for each main logistic classifier.

Results show that logistic classification models and their variants correctly predict the proper gel technology in more than 85% of projects in the training and validation samples with a minimum AUC of 0.9375. We also used a prediction profiler to visually monitor performances of the classifiers and certain tendencies were identified by the investigation of the mispredicted projects. The novelty of the new methodology is its capability to predict the most applicable gel technology for undiagnosed injection wells.

Introduction

Among conformance improvement technologies, polymer gels have been proven to be effective in addressing water production problem and in increasing oil recoveries in mature oilfields. However, the recognition of the best suited gel technology is not an easy task for operators and reservoir engineers. This largely is due to existence of numerous types of the conformance problems and gel technologies, and the fact that treatment of a specific problem requires a distinct gel technology. Also, characteristics of conformance issues which are the selection parameters are evaluated using several reservoir properties and diagnostic techniques. Consequently, many diverging and sometimes qualitatively motivated opinions have been proposed on the applicability of polymer gels as shown in

Table 1. Furthermore, costly diagnosis techniques make the preliminary assessment of the potential gel system extremely important in these capital sensitive gel projects.

Table 1. Some Expert Opinions for Drive-fluid Channeling Strength Used in Evaluation of Polymer Gels Applicability

Parameter	Weak Channeling	Strong Channeling	Reference
Problem Zone Permeability	< 2000 md	> 2000 md	Sydansk & Southwell (2000)
	<10 Darcies	> 10 Darcies	Sydansk (2007)
Permeability Contrast	$K_{Streak} > (2\text{-}10)\ K_{Matrix}$	$K_{Streak} > (50)\ K_{Matrix}$	Baker et al. (2012)
	$K_{high} < 1000\ K_{Matrix}$	$K_{high} > 1000\ K_{Matrix}$	Sydansk (2007)
Permeability Variation	DPc > 0.6	-	Reynolds and Kiker (2003)
	0.55 < DPc < 0.7	DPc > 0.7	Castro et al. (2013)
Drive-fluid Injectivity	< 10 bpd/psi	> 20 bpd/psi	Pipes & Schoeling (2014)
	-	> 5 Expected [1]	Tweidt et al. (1997)
Recovery factor	-	< 33 %	Montoya Moreno et al. (2014)
Flow Regime	Radial	Linear	Sydansk (2007)
Interwell Communication[2]	< 0.5	> 0.5	Baker et al. (2012)
Formation Type	-	Naturally Fractured Unconsolidated	Current Study
Drive-fluid Breakthrough Time	Months to years	Weeks to Months	Current study
Tracer breakthrough Time	Weeks to Months	Hours to Days	Current study
Water Cut Increment Rate	< 0.5 per year	> 0.5 per year	Current Study

(1) Based on average reservoir parameters, (2) correlation coefficient of producer-injector pressures or flow rates.

Reservoir engineers usually refer to screening criteria to identify the potential enhanced oil recovery (EOR) processes for a given reservoir. EOR screening criteria represent the intervals of validity of each influential reservoir and fluid property based on the successful field tests, engineering considerations, and experts' opinions (Alvarado and Manrique 2010). Screening criteria are generally classified into two classes depending on the form and driver of the method itself: conventional and advanced. For traditional guidelines, screening criteria are represented by the ranges of the influential reservoir/fluids characteristics that were extracted from successful field trials. The driver of this type of EOR screening criteria is the simple comparison of a given reservoir conditions with the prescribed ranges. Thus, they provide "go / no-go" decision type criteria and are incapable of ranking the candidate solutions. Advanced screening criteria use artificial intelligence and machine learning techniques where historical field data are used to train classifiers that identify the candidate EOR processes based on the similarity. Their outcomes are usually the probabilities of the considered technologies; therefore, they can rank the proposed solutions and indicate an analog for the field under evaluation.

Artificial intelligence and machine learning techniques have been widely and successfully applied in screening and ranking of different EOR techniques. Alvarado et al. (2002) pioneered the application of machine learning in this field and since then, many advanced models have been developed to screen and rank EOR processes (40 studies based on the SPE papers). However, to the best of our knowledge, no study has been accomplished for gel technologies. The evaluation of polymer gels is basically a multiple screening problem in which all considered gel technologies are simultaneously assessed for a given field. Recall that conventional guidelines lack ranking functionality and might produce contradictory results in such situations (i.e., multiple screening).

Furthermore, for sandstone reservoirs that exploited by waterflooding, the traditional screening criteria have poor discriminating powers as their validity limits (application ranges) are intersected over wide intervals as shown in Figure 1 (Aldhaheri et al. 2016a). To demonstrate the weak selectivity of the conventional guidelines, an illustrative case that has common parameter values was evaluated using polymer gels screening excel spreadsheet (Aldhaheri et al. 2016a). Figure 2 obviously shows that for these common reservoir conditions, three gel technologies are applicable (green cells). Here, a question might rise that a reservoir may exhibit multiple forms of permeability heterogeneity, so then it is normal that more than one gel technology is applicable. However, it is still favorable to rank these potential agents. Finally, Aldhaheri et al. (2016b) illustrated that 13 different parameters have been used to characterize drive-fluid channeling, the most important parameter in polymer gel applicability evaluation process. Interestingly, eight of these parameters are considered in the traditional screening guidelines; the matter that implies that there are large knowledge potentials in the data of the screening parameters that can be extracted if the right tools applied.

Evidently, there is a persistent need for efficient screening tools for polymer gels that combines both robust statistical methods and reservoir engineering best practices. This paper aims to extend the research on the screening of polymer gels by specifically investigating why machine-learning techniques should be adopted for the distinguishing of gel technologies. We utilized logistic regression technique to create classification rules based on the historical field trials of four in-situ gel systems.

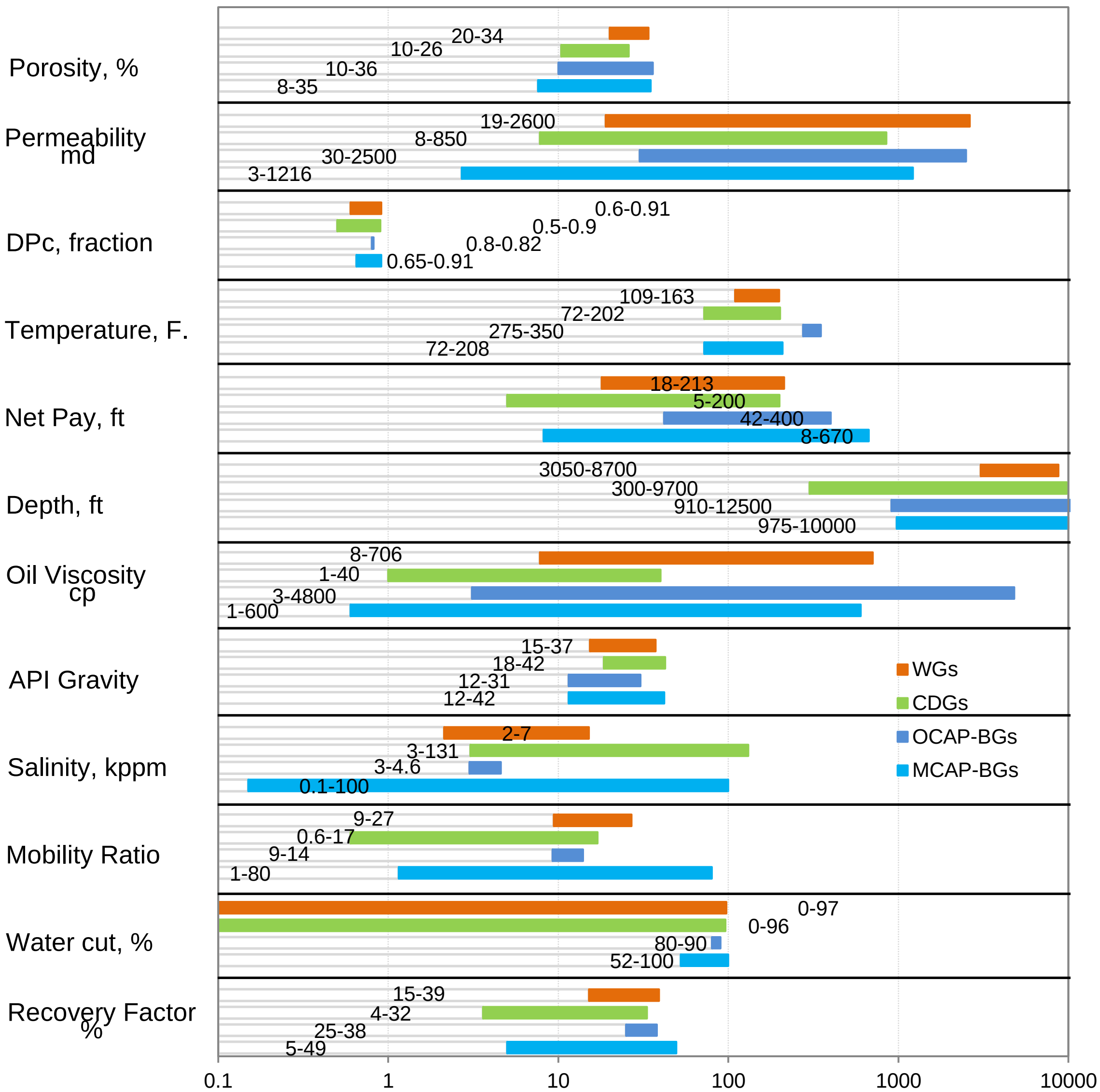


Figure 1. Conventional screening criteria for polymer gel technologies

In the next sections, gel systems, logistic regression principles, and data compilation and exploration are illustrated. The observations and application tendencies that called for the development of multiple probabilistic models with variants will be discussed. Then, the tasks of data processing, variable treatment and selection, and model construction and validation are discussed in details. Some observations about the performances of the logistic models and the misclassified projects are presented as well.

Polymer Gel Conformance Improvement Technologies

Polymer gels have been proven to be an effective solution for a variety of conformance issues, especially in injection wells. For this well type, synthetic polyacrylamide-based gels are the most widely applied chemical system (Lantz and Muniz 2014). In this paper, four partially hydrolyzed polyacrylamide, in-situ gelling conformance systems are considered for screening purposes. The following is a brief description of these systems and more details can be found in the work of Aldhaheri et al. (2016a).

Composite Screening of Polymer Gels

Field: Unknown

Porperties	Values	MCAP-Bulk Gels	OCAP-Bulk Gels	Collodial Dispersion Gels	Weak Gels
Lithology	Sandstone	Carb & SS	Carb & SS	Sandstone	Sandstone
Formation	Matrix-rock	All	Mat & Unc	Mat & NF	Mat & Unc
IOR/EOR Process	Waterflooding	WF,PF,CO2	WF,CO2,Steam	WF,PF	WF,PF
Porosity, %	20	8-35	10-36	10-26	20-34
Permeability, md	50	3-1216	30-2500	8-850	19-2634
DPC, fraction	0.8	0.65-0.91	0.8-0.82	0.5-0.9	0.6-0.91
Temperature, F	150	72-208	275-350	72-202	109-163
Net Thickness, ft	50	8-670	42-400	5-200	18-213
Depth, ft	5000	975-10000	910-12500	300-9791	3051-8727
Oil Viscosity, cp	40	0.8-600	3-4800	1-40	9.5-706
API Gravity, deg.	30	11-42	12-31	18-42	15-37
Water Salinity, ppm	4000	150-100,000	3000-4600	3000-130,000	2000-7000
Mobility Ratio, M	14	1-80	9-14	0.6-17	9-27
Water Cut, %	85	52-100	80-90	0-96	0-97
Recovery Factor, %	32	5-45	25-38	4-32	15-39

Green = Satisified
Red = Unsatisifed

Figure 2. Polymer gel screening results for an illustrative sandstone reservoir field produces by waterflooding

Bulk Gels. Bulk gels (BGs) can be formed using high molecular weight (8-13 million daltons) partially hydrolyzed polyacrylamides with a crosslinker. Depending on the type of the crosslinking agent, two systems have been developed. For MARCIT^{SM} gels developed by Marathon Oil Company, polyacrylamides are crosslinked using a trivalent metal ion, which is usually Chromium (III) (Sydansk and Smith 1988) and applied in a formation temperature less than 220°F (Sydansk and Southwell 2000).

For high temperature applications, medium molecular weight polyacrylamide polymers are crosslinked with an organic agent and a stabilizer to delay the gelation process. An example of this specialized chemistry is the UNOGEL technology developed by Union Oil Company of California (UNOCAL) which can be applied in temperature ranges of 200 to 300°F (Norman et al. 2006). In this study, these gels are depicted as organically-crosslinked-polyacrylamides bulk gels (OCAP-BGs) to discriminate them from the metallically-crosslinked-polyacrylamide systems described above (BGs).

Colloidal Dispersion Gels. Colloidal dispersion gels (CDGs) are in-situ microgel aggregates that are formed by crosslinking of low concentrations (150 to 1200 ppm) of high-molecular-weight (> 22 million daltons) hydrolyzed-polyacrylamide polymer with aluminum citrate or chromic citrate and produce weak gels. Such low polymer concentrations are not enough to form a continuous network, and thus, they produce a solution of separate gel bundles that are almost spherical particles with sizes in the range of nanometers of 50 to 150 nm (Castro et al. 2013). These gels can flow under differential pressures that are greater than their transition pressures, as it was experimentally demonstrated by Mack and Smith (1994). It is noteworthy that in this study, we have considered only CDG historic cases that involved the co-injection of the polymer and crosslinker where the early sequential gel applications were precluded.

Weak Gels. Weak gels (WGs) are a subdivision of bulk gels that terminologically have been separated to distinguish their objectives of application from those of the original technology (i.e. BGs). Essentially, these agents are low to intermediate polymer concentrations, weak strength bulk gels. They can have the same or different mechanisms of BGs for improving sweep efficiency depending on how and where they are applied. Some researchers have implied that any bulk gel system (regardless of its concentration) is a weak gel if it forms a flowing gel in the reservoir conditions under certain ranges of pressure gradients. Sheng (2011) mentioned that weak gels have high resistance to flow but are still able to flow so they can be injected deep into the reservoir. Han et al. (2014) provided similar ideas and referred to WGs and CDGs as flowing gel processes. Furthermore, Song et al. (2002) and Lu et al. (2010) pointed out that WGs are oil-displacement agents in addition to their function as blocking agents. In this study, all reviewed weak gel history cases are from Chinese oilfields where this conformance system has been extensively applied in heavy oil, unconsolidated sandstone reservoirs as an in-depth fluid diversion technology.

Logistic Regression Principles and Performance Measures

Logistic regression is considered one of the most reliable classification techniques and has become a regularly used tool by most statisticians. Its S-shaped distribution function is encountered in many fields including banking, demographics, epidemiology, psychology, and marketing. Due to its many qualities, this technique has taken the place of its rival in many supervised classification problems, especially scoring problems (Tuffery, 2011).

In statistics, logistic regression is used to model categorical dependent variables that have discrete qualitative outcomes. It can handle qualitative variables with two or more responses, and independent variables can be quantitative or qualitative. It is classified as binary, multinomial, and ordinal logistic regression when the response variable has 2, ≥3 nominal, ≥3 ordered categories, respectively. Logistic regression measures the relationship between these categorical responses that have S-shaped distribution as shown in Figure 3 with the predictors and produces a probability of a response Prob($Y = 1 / X = x$) that is ranging from 0 to 1. For this S-curve, we can write this probability $\pi(x)$ = Prob($Y = 1 / X = x$) using the sigmoid function:

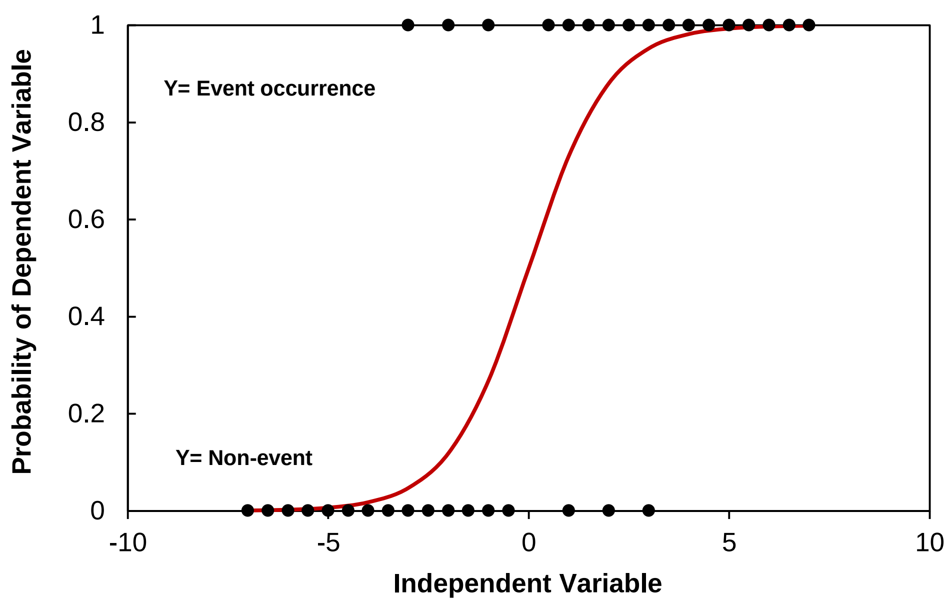


Figure 3. Illustration of the sigmoid S-shaped logistic distribution function

$$\pi(x) = \frac{e^{\beta_0 + \sum_j \beta_j x_j}}{1 + e^{\beta_0 + \sum_j \beta_j x_j}} \quad (1)$$

The ratio of the probability of an event occurring π(x) to the probability of non-event (1-π(x)) is called the odds. In logit version, the log of the odds is modeled as a linear combination of regressors X_s as shown below:

$$\log\left(\frac{\pi(x)}{1-\pi(x)}\right) = \beta_0 + \beta_1 X_1 + \cdots + \beta_{1p} X_p \quad (2)$$

When X_i changes from *x* to *x* + 1, the variation in the ratio of the probability of the event occurring *Y*=1 against the probability of non-event Y=0, is presented as odds ratio:

$$OR = \frac{\pi(x+1)/[1-\pi(x+1)]}{\pi(x)/[1-\pi(x)]} = e^{\beta_i} \quad (3)$$

In this case, logit (π(*x*)) increases by the coefficient β_i of X_i and the odds are multiplied by exp(β_i) as illustrated in the above equation. Logistic regression employs maximum likelihood method to estimate the coefficient β_i of the model and its models are not constrained by the assumption of normally distributed data (Sharma, 1996). In this supervised classification technique, historical data are used to train a model to build a classification rule that is then utilized to classify new candidates into one of the considered responses. Logistic regression reliability is easy to monitor using a number of statistical measures (Tuffery, 2011). In this study the following comprehensive performance indicators were used to evaluate the goodness-of-fit of the developed probabilistic models:

1- Entropy R^2 (U): the ratio of the difference to the reduced negative log-likelihood values. It is sometimes referred to as *U*, the uncertainty coefficient, or as McFadden's pseudo R^2. This measure ranges from zero for no improvement to 1 for a perfect fit.

2- Correct Classification Rate (CCR): is a measure to assess predictivity of a scoring model that ranges between 0 and 1. It is represents the fraction (or percentage) of the correctly classified observations and expressed as:

$$Correct\ Classification\ Rate = \frac{(TP+TN)}{TP+FN+FP+TN} \tag{4}$$

Where TP stands for True positives (events predicted as events), TN for the True negatives (non-events predicted as non-event), FP for the False positives (events predicted as non-events), and FN for the False negatives (non-events predicted as events). In other words, this criterion is the ratio (0-1) of the number of correctly classified cases to the total number of observations used in construction or testing of a model.

3- Area Under ROC Curve: AUC is a global performance measure of logistic regression models that assesses the area under the Receiver Operating Characteristics Curve shown in Figure 4. The ROC curve was originated in signal detection and processing field and represents a graphical representation of the discriminatory power of a binary classification system and it is created by plotting the true positive rate known as sensitivity (*SENS*) against the false positive rate or (1-specificity) where specificity (*SPEC)* indicates the proportion of correctly predicted non-events. AUC values range from 0 to 1 where 1 represents a perfect model and an area of 0.5 indicates a worthless model (Tuffery, 2011).

$$Sensitivity = \frac{TP}{TP+FN} \tag{5}$$

$$Specificity = \frac{TN}{FP+TN} \tag{6}$$

$$AUC = \int_0^1 SENS(1-SPEC).d(1-SPEC) \tag{7}$$

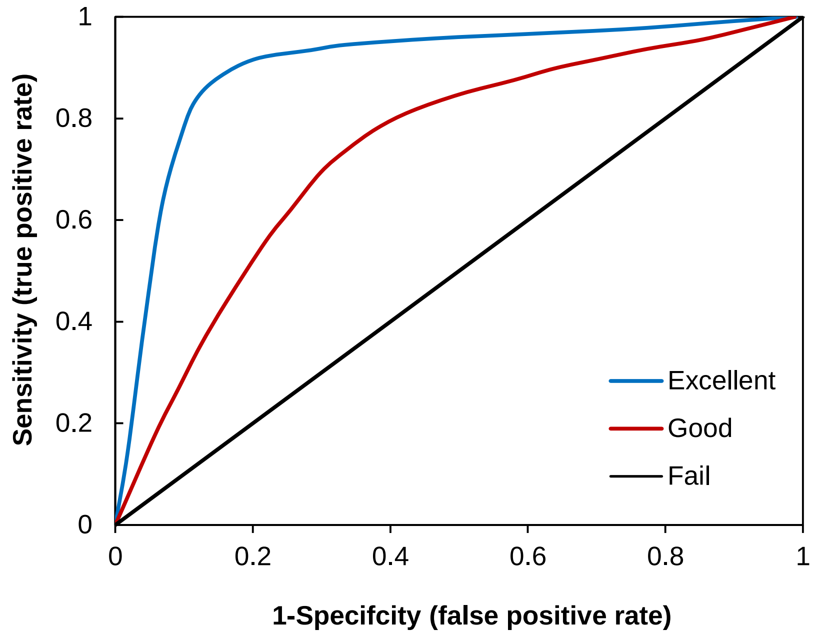


Figure 4. Illustrative Receiver Operation Characteristic Curve (ROC) plot shows typical curves for a classification model

On the basis of the strengths and weaknesses of the above measures, many authors have referred to AUC as the most comprehensive measures to assess the discriminatory power of the logistic models especially in banking scoring studies (Van Gool et al. 2009).

It is important to know why logistic regression has been adopted in favor of other supervised classification techniques. We identified that reservoir lithology and formation type considerably influence the applicability criteria of some influential parameters such as porosity, permeability, depth, and oil viscosity as shown in Figure 5 for the reservoir permeability. If validity limits of properties were established without considering these affecting aspects, then the results of processing such mixed data will falsify where polymer gels have actually been applied (Aldhaheri et al. 2016a). Therefore, for adequate screening, analyses should be performed according to the affecting aspects such as lithology, formation type, and IOR/EOR process. This means that there is a classification rule (secondary) for every category of the above aspects that is required to individually taken into considerations. Logistic regression creates an odd ratio for each category of the qualitative variables, which allow us to have sub classification rules that account for these categories as it illustrated in the next sections (Tuffery, 2011).

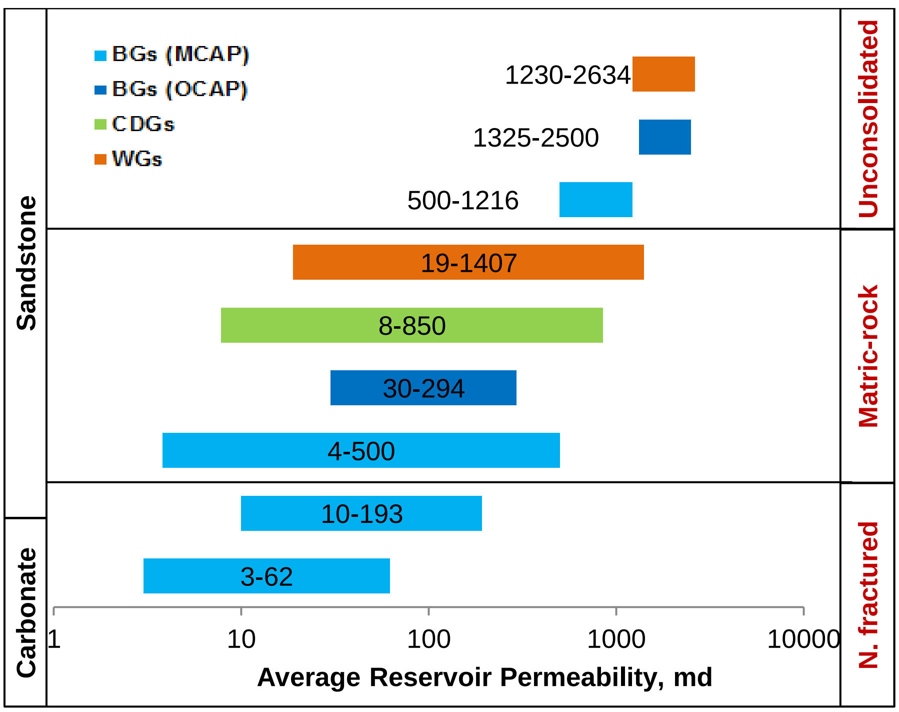


Figure 5. Comparison of permeability applicability ranges for polymer gels according to reservoir lithology and formation type

Database Compilation and Data Processing

The data preparation step deals with the choice of the desired variables, the compilation of data sets, and the treatment of missing values and outliers. A specialized database was built from gel treatment case histories published in SPE papers and U.S. Department of Energy reports from 1978 to 2015. Currently, the database includes 111 field trials for the considered technologies and over 50 parameters that include reservoir and fluids properties, treatment operating parameters, and performance indicators. Table 2 shows a summary of project and treatment frequencies in the current survey of injection well gel field applications. For reservoir and fluids characteristics, the reported values are the averages from the properties of the reviewed fields. Additionally, some parameters' estimates are time-specified, and the provided data are their values at the times of evaluations.

Table 2. Statistics of Projects and Treatments in Injection-Well Gel Field Project Survey

Gel Technology	No. of Projects	No. of Treatments	Treatment per Project (TPP)
Bulk Gels	57	607	10.6
Microgels (CDGs)	44	80	2
Weak Gels	10	110	11
Total	**111**	**797**	**7.2**

Property Selection. In total, 19 variables have been considered in this study, where several of these parameters are included in the conventional screening criteria for polymer gels (Aldhaheri et al. 2016a). The variables include 15 reservoir rock and fluids properties and four production-related parameters such as water cut and recovery factor. Table 3 presents a descriptive statistical summary for the continuous explanatory variables and Figure 6 shows distributions of gel systems according to the categories of the three qualitative aspects that are reservoir lithology, formation type, and IOR/EOR process.

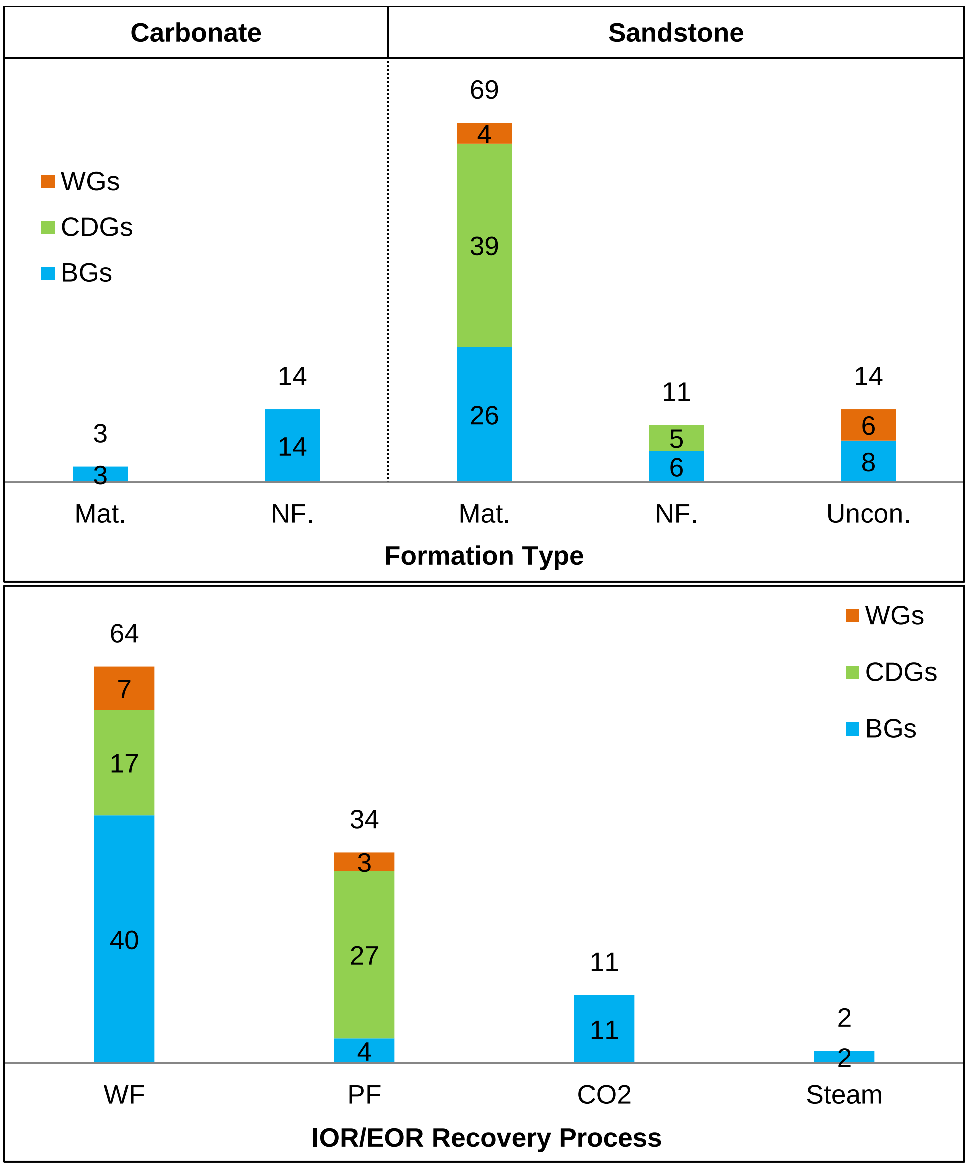


Figure 6. Distributions of polymer gel projects according to reservoir lithology/formation type (left) and IOR/EOR process (right)

In this study, the variable "flood life" represents the time period from the beginning of injection operations in the targeted wells to date of the treatment. This parameter and water cut were used to represent the timing of the gel treatments in the field development stages. It is noteworthy that for OCAP-BGs, all available field trials (seven projects) were used in the development of first model regardless their technical or economic feasibility due to the low number of the available projects for this technology. Generally, field projects were divided based on the type of gel system into a 75% training set and a 25% test set that were utilized in the out-of-sample validation to demonstrate the statistical accuracy of the developed models.

Missing Data Treatment. For reservoir and fluids properties, missing data were progressively evaluated using three different approaches. First, the required information for the reservoirs of interest was extracted from other SPE papers that deal with application of IOR/EOR processes for the field. Other sources also were utilized for data filling purposes like National Petroleum Council Public Database (1995), Wyoming Oil Reservoir EOR Database (2010), Oil and Gas Journal Data Book (2006), and Oil and Gas Journal EOR Surveys (2008). Secondly, we have taken the advantage of existence of good correlations for some properties to predict the missing values. Good association powers were obtained for permeability vs. porosity, and viscosity vs. API gravity. However, for properties that really have low number of data points such as DPc, mobility, and water salinity, we did not obtain good association trends. Therefore, for these properties and other operational parameters, the multivariate imputation by chained equations (MICE) package in R software (Van Buuren and Groothius, 2009) was used to estimate missing values. The distinctive feature of this imputation method lies in its

Table 3. Descriptive Statistical Summary of Screening Parameters in Gel Project Database

Parameter	ϕ	K_{min}	K_{avg}	K_{max}	DPc	Contrast	T	h
Units	%	md	md	md	fraction	ratio	°F	ft
Points Count	111	93	106	95	77	92	111	98
Missing Points	0	18	5	16	34	19	0	13
Mean	18.7	72.4	338.3	1936.6	0.77	7372	153.6	87.3
Median	17.5	10	109.5	1000	0.77	100	145.4	37.4
St. Dev	6	182	539	3341	0.09	52420	48	120
CV	0.35	2.5	1.59	1.7	0.11	7.1	0.31	1.38
Minimum	7.6	0.01	2.7	5	0.50	1.94	72	5
Maximum	36	1035	2634	29511	0.97	500000	350.3	670
1st quartile	15	1	34	290	0.71	17.3	122	23
3rd quartile	22	60	341	2992	0.82	600	177	80
IQR	7	59	307	2702	0.11	582.7	55	57
Lower Limit	3	-87.5	-427	-3763	0.55	-857	40	-63
Upper Limit	33	148.5	802	7046	0.99	1474	258	166
# of Outliers	5	10	15	2	1	14	5	16

Parameter	D	μ	API	Sal	M	WC	FL	RF
Units	ft	cp	deg.	ppm	ratio	%	year	%
Points Count	111	101	104	61	32	78	98	76
Missing Points	0	10	7	50	39	33	13	35
Mean	5891	92.8	27.2	37206	8.6	62.2	11.5	19.4
Median	5628	11.0	25	15781	4.7	83.3	6.5	15.7
St. Dev	2582	488	8	43965	14	39	12.7	12
CV	0.44	5.26	0.28	1.18	1.66	0.63	1.1	0.64
Minimum	300	0.3	11.5	150.0	0.6	0	0	1.6
Maximum	12500	4800	42.5	173207	80	100	53	49.4
1st quartile	4010	4	21	5496	2	12	2	9
3rd quartile	7875	28	34	67382	9	95	18	25
IQR	3866	24	13	61886	8	83	16	16
Lower Limit	-1789	-33	1	-87333	-10	-112	-22	-16
Upper Limit	13673	65	54	160211	21	219	43	49
# of Outliers	0	16	0	2	2	0	5	0

maintaining of the original variability of the incomplete data sets, so imputed values do not influence the validity limits of screening guidelines.

This method randomly estimates five values for missing data points that are within the validation limits (minimum, maximum, and gaps) of the subject parameter. In addition, this method uses the predictive mean matching technique to estimate the missing values. These two features of MICE package enabled us to minimize the bias (toward gel systems that have large number of projects) that was observed when other imputation techniques used. Finally, from the five imputed data sets for each parameter, we selected one that maintains the original univariate discriminating power (between gel systems) for the parameter under evaluation using logistic Entropy R^2.

Outliers Identification and Treatment. To ensure data quality, outliers were detected using the scatterplots, the interquartile range method (IQR), and the three standard deviation rules. The IQR method indicated that some data sets have large number of potential outlier points as shown in Table 3. In this study, reservoir engineering viewpoints have been adopted in parallel with statistician standpoints to judge possible outlier points, and thus, no data points were ruled out in this study. Further illustration of this step can be found in Aldhaheri et al. (2016a). Finally Normality test was performed to check the data using Shapiro-Wilk W test in JMP® where DPc and depth data sets were identified as having normal distributions. A logarithm transformation was taken for both data sets; however, no improvements were obtained in terms of separating powers of the constructed models.

Collinearity of Independent Variables. For multiple regression techniques, linear links between independent variables represent an important statistical issue. This potential issue is highly expected in analysis of EOR data sets because some reservoir rocks and fluids properties are physically related. For example, porosity and permeability, temperature and depth, and oil viscosity and API gravity are physically linked based on reservoir engineering principles. In addition, some EOR processes function based on certain values for reservoir characteristics such steam injection with respect to as oil viscosity; thus, reservoir properties might be associated with EOR methods. The existence of strong correlations between independent variables causes the problems of collinearity and multicollinearity that reduce the predictive powers of the developed models especially for validation samples.

The collinearity is assessed by the mean of the Pearson correlation coefficient for numerical predictors and by the Chi-Square test for qualitative variables. For quantitative predictors, an empirical rule is used that states that the correlation is unacceptable when the correlation coefficient exceeds 0.9, very risky when the coefficient exceeds 0.8, and needs to be treated with caution when it exceeds 0.7 (Tuffery, 2011). The multicollinearity between both types of independent variables is frequently checked by mean of the variance inflation factor (VIF) and as a rule of thumb it should be less than 5 or at least 10 (Tuffery, 2011).

In this study, we indicated that compiled data has generally weak to moderate associations based on the aforementioned rules. This simply is because that the data was collected for different gel systems in terms of mechanisms and specifications. For variable pairs, the correlation matrix presented in Table 4 below shows a weak association for the majority of properties and a moderate association for few properties with a maximum correlation coefficient 0.71. Chi-Square test shows a strong association for categorical variables; however, there were cells with a frequency of less than 5; the matter that make this test not useful. Most importantly, variance inflation factors were estimated for both quantitative and qualitative predictors that considered in the final models and were less than 5 for all variables and all models with a maximum of 4.69 as shown in Table 5 for G4 Model which will be discussed in the next sections. The above results indicate that there is no damage in the predictive powers of logistic models that may result from the collinearity and multicollinearity issues. It is important to note that qualitative predictors were transformed into dummy variables to facilitate the estimation of variance inflation factors.

Selection and Treatment of Independent Variables

Discriminatory power is an important consideration in performance and selection of a supervised classification model. The statistical accuracy or the goodness-of-fit of a predictive model always increases by including more independent variables. However, including large number of variables would make the model unnecessarily large and deter the candidate injectors when confronted with the required number of properties and parameters. Therefore, the authors typically adopt explanatory variable selection techniques to identify the most discriminating predictors.

Several variable selection methods have been proposed for logistic regression based on different logic principles (Bursac et al. 2008). Some methodologists (especially in Epidemiologic) suggest the inclusion of all clinical and other relevant variables in the

Table 4. Pearson Correlation Matrix for all Quantitative Independent Variables

	ϕ	K_{min}	K_{avg}	K_{max}	DPc	Con	T	h
ϕ	1.00	0.45	0.71	0.42	0.27	0.22	0.17	0.13
K_{min}	0.45	1.00	0.58	0.10	0.10	0.05	0.19	0.12
K_{avg}	0.71	0.58	1.00	0.66	0.20	0.15	0.13	0.07
K_{max}	0.42	0.10	0.66	1.00	0.23	0.11	0.01	0.12
DPc	0.27	0.10	0.20	0.23	1.00	0.17	0.10	0.19
Con	0.22	0.05	0.15	0.11	0.17	1.00	0.02	0.07
T	0.17	0.19	0.13	0.01	0.10	0.02	1.00	0.06
h	0.13	0.12	0.07	0.12	0.19	0.07	0.06	1.00
D	0.35	0.19	0.29	0.15	0.29	0.07	0.46	0.10
μ	0.36	0.47	0.50	0.10	0.23	0.01	0.33	0.15
API	0.43	0.24	0.42	0.27	0.09	0.13	0.10	0.21
Sal	0.16	0.15	0.21	0.08	0.01	0.07	0.06	0.19
M	0.55	0.36	0.51	0.32	0.26	0.01	0.14	0.01
WC	0.24	0.10	0.08	0.12	0.37	0.07	0.01	0.25
FL	0.08	0.01	0.04	0.00	0.18	0.03	0.02	0.35
RF	0.11	0.02	0.04	0.02	0.15	0.04	0.06	0.12

	D	μ	API	Sal	M	WC	FL	RF
ϕ	0.35	0.36	0.43	0.16	0.55	0.24	0.08	0.11
K_{min}	0.19	0.47	0.24	0.15	0.36	0.10	0.01	0.02
K_{avg}	0.29	0.50	0.42	0.21	0.51	0.08	0.04	0.04
K_{max}	0.15	0.10	0.27	0.08	0.32	0.12	0.00	0.02
DPc	0.29	0.23	0.09	0.01	0.26	0.37	0.18	0.15
Con	0.07	0.01	0.13	0.07	0.01	0.07	0.03	0.04
T	0.46	0.33	0.10	0.06	0.14	0.01	0.02	0.06
h	0.10	0.15	0.21	0.19	0.01	0.25	0.35	0.12
D	1.00	0.22	0.06	0.18	0.33	0.41	0.17	0.06
μ	0.22	1.00	0.31	0.10	0.66	0.07	0.02	0.14
API	0.06	0.31	1.00	0.07	0.46	0.14	0.34	0.33
Sal	0.18	0.10	0.07	1.00	0.13	0.10	0.19	0.04
M	0.33	0.66	0.46	0.13	1.00	0.15	0.03	0.15
WC	0.41	0.07	0.14	0.10	0.15	1.00	0.41	0.46
FL	0.17	0.02	0.34	0.19	0.03	0.41	1.00	0.51
RF	0.06	0.14	0.33	0.04	0.15	0.46	0.51	1.00

Table 5. Values of Variance Inflation Factor for Independent Variables Considered in G4 Model

Term	Variance Inflation Factor (VIF)
Intercept	-
Dummy Lithology [0]	1.98
Dummy Formation [0]	2.82
Dummy Formation [1]	3.36
Dummy IOR2 [0]	4.69
Dummy IOR2 [1]	3.45
ϕ	3.22
K_{avg}	3.98
DPc	1.43
T	3.73
h	1.33
D	3.67
μ	3.12
WC	2.37
RF	1.82

model regardless of their significance in order to control for the confounding. This approach, however, can lead to numerically unstable estimates and large standard errors (Hosmer and Lemeshow 2013). More common, predictors' selection is based on the statistical significance as in the stepwise regression methods; however, this strategy may results in omitting of some surely relevant variables. Statistical significance has been combined with change-in-estimate criteria to develop what so called the purposeful selection algorithm by Hosmer and Lemeshow (2013). For EOR screening, we noticed that most previous advanced methodologies have utilized all available variables, which means that the selection of the predictors has typically relied on intuitive reasoning and historical precedent.

For logistic regression, Hand and Henley (1997) describe three approaches to select the right predictors in a classification problem including expert knowledge, stepwise regression, and AUC heuristic procedure. Initially, the most discriminating variables are nominated based on the intuitions of the experts and the previous studies (Hosmer et al. 2013). Tuffery (2011) mentioned in his book that variable selection is crucial and it essential to have a thorough knowledge of the data and their functional significant. He has also suggested the use of variable clustering for ensuring that at least one representative has been selected for each class of variables. In this study, our first goal is to develop models that are simultaneously able to select and screen gel systems of interest. A model that includes only the discriminating variables regardless their relevance to the gel treatment applicability will select a gel technology for given injector. However, this model serves only as a classifier and it does not have the ability to check whether that the other gel technical guidelines have been satisfied or not. On the other hand, investigating applicability of polymer gels requires considering all technically relevant variables, so the resulted models can nominate one technology in favor of others and ensure its compatibilities with reservoir properties and injected fluids (EOR advisor). Therefore, we have given the priority to the discriminating parameters that appeared in the conventional screening guidelines which are listed in the first column of Table 6.

Secondly, we detected and ordered the most predictive variables based on the univariate entropy R^2 and the statistical significance as shown in the second column of

Table 6. Then stepwise regression based on the Bayesian information criterion (BIC) was used to provide an initial combination of the variables, which indicated the 13 variables (or categories) marked in the third column of Table 6. As a third approach, we utilized AUC heuristic technique to achieving a balance (trade-off) between the number of variables in the model and a comprehensive measure of model goodness-of-fit. Baesens et al. (2009) proposed this procedure in the credit scoring, which removes in each consecutive step the variable which causes the smallest increase in AUC. A perfect predictive model can be obtained by inclusion of 17 variables out of the 19 available properties based on both R^2 and AUC as shown in Figure 7. However, such model may tend to over-fit as mentioned earlier; therefore, we have taken the following five perspectives into considerations to find the right number of variables:

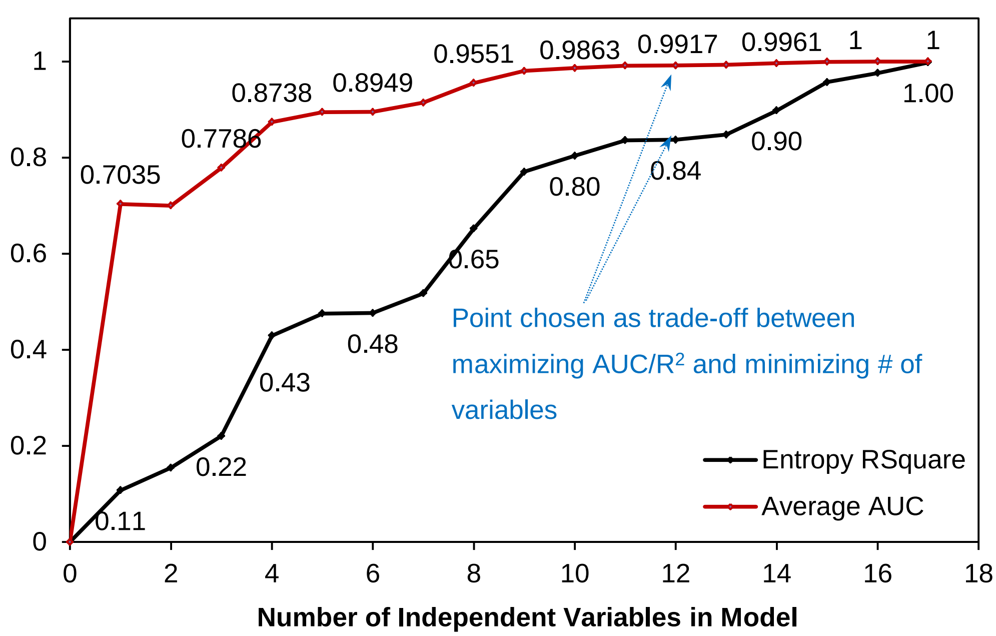


Figure 7. AUC heuristic variable selection approach for logistic model bias-variance trade-off

Table 6. Summary of Independent Variables Selection Criteria for Logistic Classification Models

Variable	Conventional Guidelines	Entropy R^2	Stepwise Regression	Data Availability
IOR/EOR process	✓	0.2221	✓	
Temperature	✓	0.2208	✓	
Water cut	✓	0.1891	✓	XX
Recovery Factor	✓	0.1777	✓	XX
Formation Type	✓	0.1674	✓	
Permeability	✓	0.1463	✓	X
Porosity	✓	0.1112	✓	
Net thickness	✓	0.0998		
Min. permeability		0.0974	✓	XX
Max. permeability		0.0869		XX
Oil viscosity	✓	0.0813	✓	X
Flood life		0.0810		X
Lithology	✓	0.0751		
Dykstra-Parsons coefficient	✓	0.0689		XX
Permeability contrast		0.0448		XX
Depth	✓	0.0361		
Mobility ratio	✓	0.0319		XXX
Water salinity	✓	0.0300		XXX
API gravity	✓	0.0004	✓	X

✓ : considered or suggested parameter, XXX: data set has few data points

Data Availability and Quality. Table 3 shows that some data sets suffer from low number of compiled data points even after several data filling campaigns. This indicates that the operators of these fields have a problem regarding the availability of data for these properties. Examples for these parameters are mobility ratio and water salinity where only 27 and 56 data points were provided in a set of 111 records. It is important to note that water salinity values might change due to injection processes conducted in the oilfields; however, most studies do not illustrate whether the provided values are updated or not. To less extent, minimum permeability, maximum permeability, DPc, and water cut are also plagued by this issue. Based on these aspects (i.e. availability and quality), we decided to rule out mobility ratio and water salinity if they approved to be insignificant by other statistical measures.

Discriminatory Powers. Variables that were identified as having good ability to differentiate responses were considered strong or important predictors. Entropy R^2, a univariate performance measure was used to evaluate this ability and to order variables as shown in Table 6. This table shows that most traditional screening variables have high R^2 and IOR/EOR process and temperature have the highest degree of selectivity. Also, it indicates that API, water salinity, mobility ratio, and depth have the weakest predictive powers. It was recognized that missing value imputation has reduced the discriminatory powers of some variables like DPc, water cut, net thickness, and recovery factor, where this reduction is dependent on the amount of missing data.

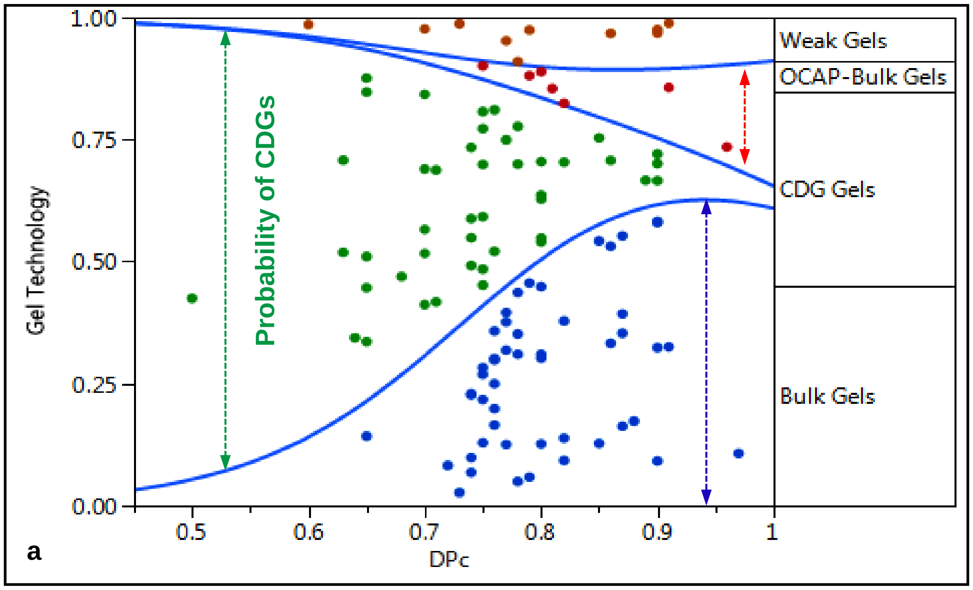
Logistic Probability Plots. In this study, we utilized the univariate logistic probability plots to examine probability distributions among response for all independent variables. The logistic probability plot gives a complete picture of what the logistic model is fitting. At each *x* value, the probability scale in the *y* direction is divided up (partitioned) into probabilities for each response category. The probabilities are measured as the vertical distance between the curves, with the total across all *Y* category probabilities summing to 1 (JMP 2015). Thus the separating curves or lines between partitions represent probability trends of the response outcomes based on the values of an independent variable.

In this stage, variables that were approved to be discriminating by the aforementioned steps and have probability patterns that match the engineering considerations and/or the well-known application trends were confirmed to be considered in model construction stage. For example, from conformance engineering principles, drive-fluid channeling strength increases with reservoir heterogeneity and BGs and CDGs are applied to treat strong and weak channeling strengths, respectively. It can be easily recognized in Figure 8-a that chances of BGs, OCAP-BGs, and WGs increase and probabilities of CDGs decrease as reservoir heterogeneity represented by DPc increases. Furthermore, Aldhaheri et al. (2016b) illustrated that BGs have been extensively applied in well-developed conformance issues that characterized by high oil recoveries. On the other hand, CDGs have been mainly applied in undeveloped problems with low recovery factors. This indicates that with increasing recovery factor, chances of BGs increase and probability of CDGs decrease. Not surprisingly, recovery factor probability plot shown in Figure 8-b adequately follows this application trends and confirm the predictive power of this parameter. Other examples for these matchings are shown in Figure 8-c and Figure 8-d for water cut and net thickness.

Alternatively, independent variables that have weak predictive powers and have complex, intersected probability patterns or have a similar pattern of a related parameter were confirmed not to be considered in the next step. Figure 9 shows that permeability contrast and minimum permeability have complicated probability distributions and mobility ratio has almost identical pattern to that of oil viscosity. It is important to note that in case of permeability contrast, the separating curve of CDGs is drawn in the middle of their cloud of points and chances of this gel system increase as contrast (heterogeneity) increases. Based on these observations, water salinity, mobility ratio, minimum and maximum permeabilities, and permeability contrast were omitted.

Data Gaps. For small populations, it is essential to examine distributions of continuous independent variables to detect possible data gaps as they substantially affect the logistic probability patterns of the response categories. In this study, a data gap in temperature data was identified that extends the maximum application limit for the metallically crosslinked systems (BGs, CDGs, and WGs) from 210 to 233°F (lower limit of OCAP-BGs) and has expanded the lower value of OCAP-BGs from 240 to 233°F as shown in Figure 10. It is important to note that the temperature range of 210 to 240°F is considered as critical interval for MCAP gel and some unsuccessful case histories are within this interval; therefore, it is essential to tackle this data gap.

Because logistic regression estimates a coefficient (odds ratio) for each category of the qualitative independent variables present in the database, a sub classification rule will be implicitly created for these categories. Distributions of continuous variables for these sub rules will be different from the main classification rules of the dependent variable if data gaps exist. While the general prediction rule is to move toward OCAP-BGs at T > 210°F, Figure 11 illustrates that naturally fractured and unconsolidated formations have their own rules as a result of the data gaps in temperature distributions.



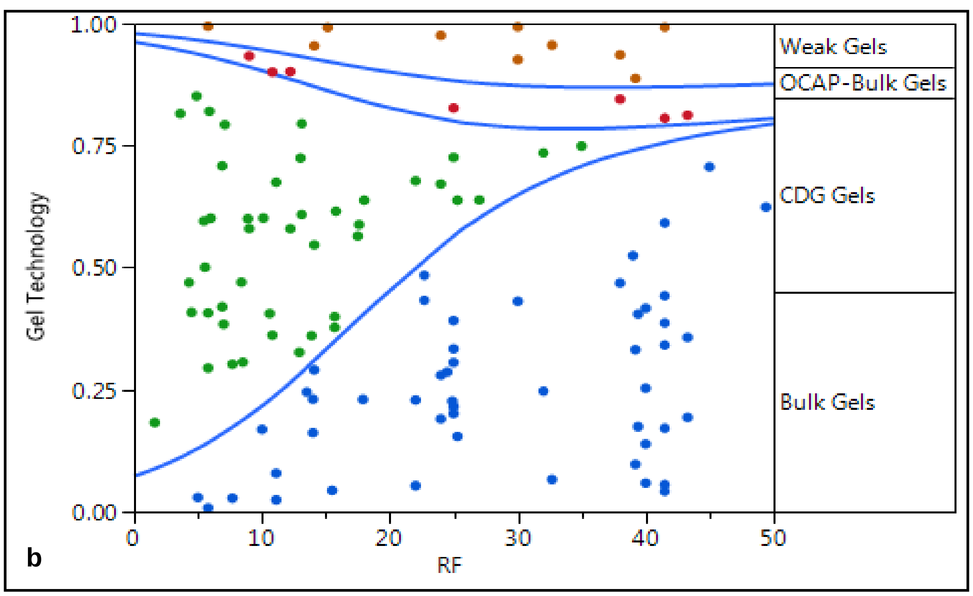
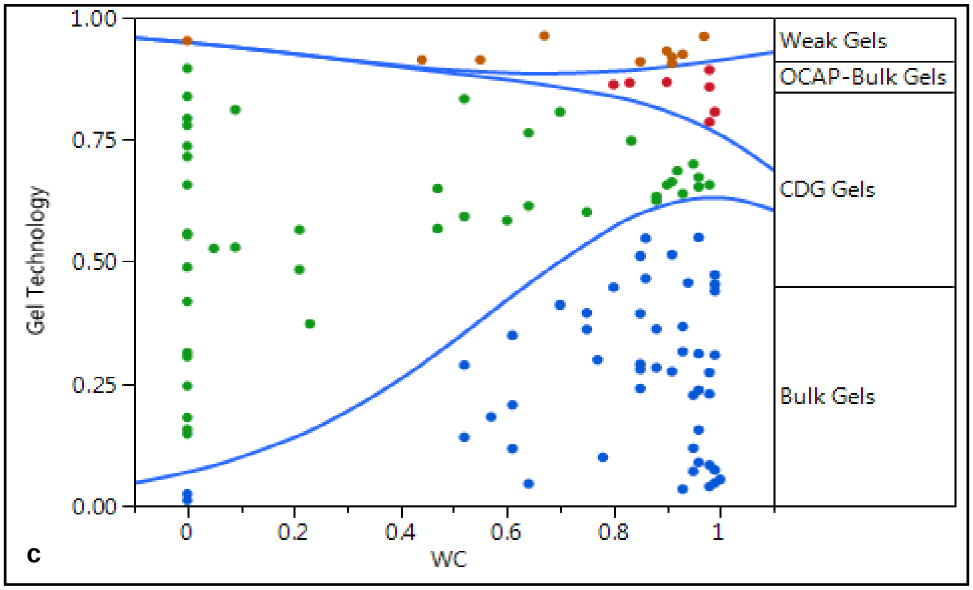


Figure 8. Distributions of logistic probabilities of gel systems for some screening parameters that match conformance considerations and/or field application trends



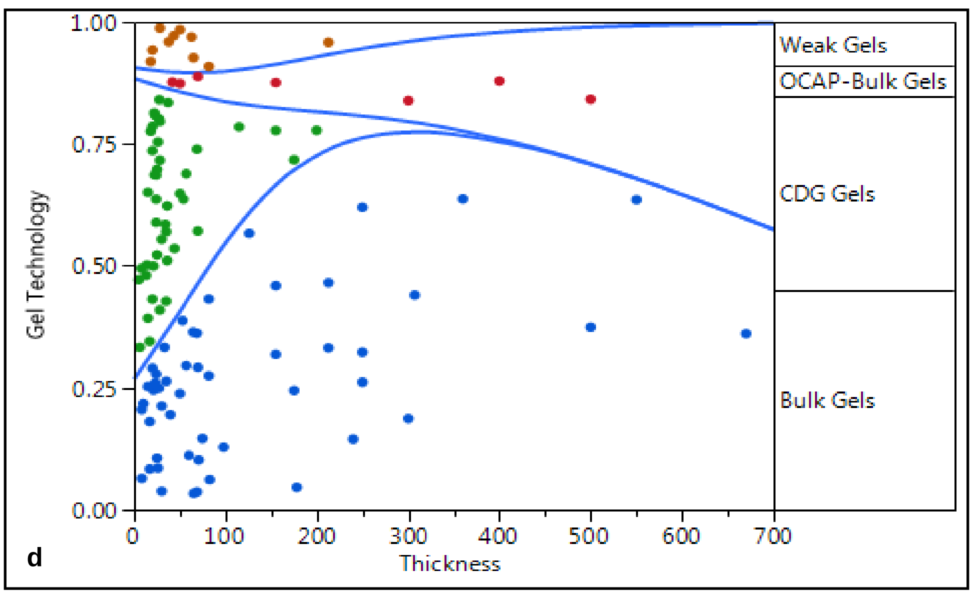
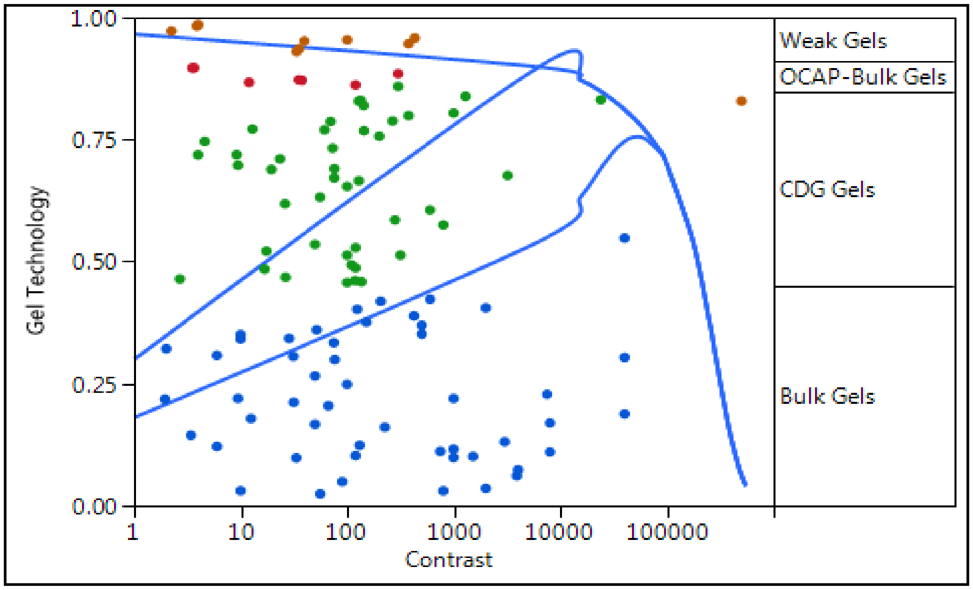


Figure 8. Distributions of logistic probabilities of gel systems for some screening parameters that match conformance considerations and/or field application trends (Cont'd)



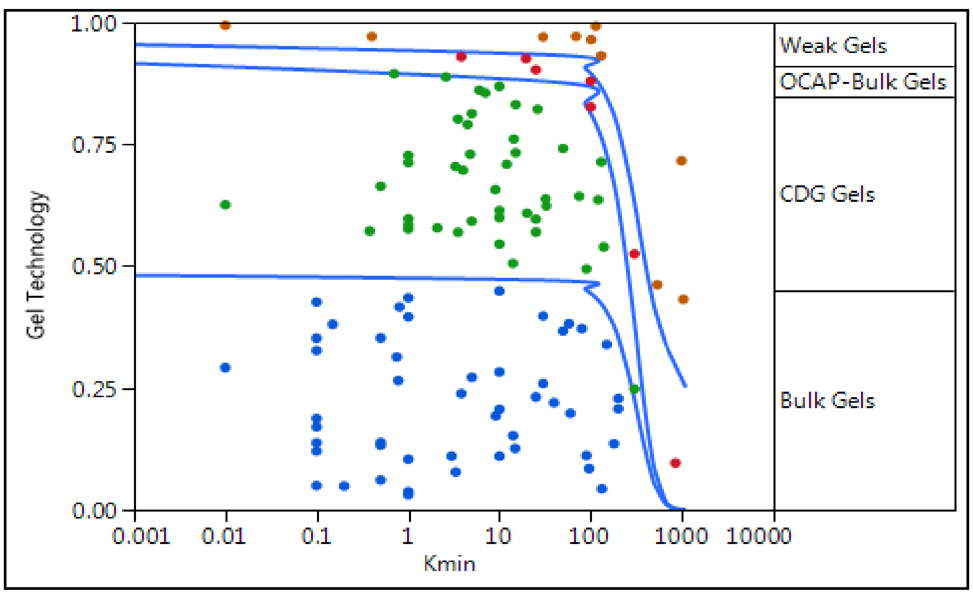
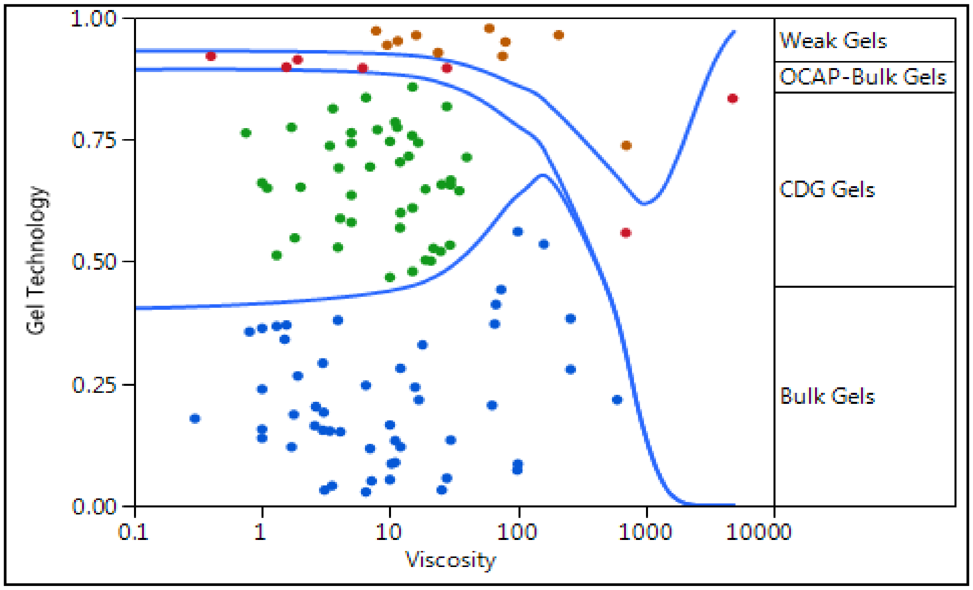


Figure 9. Logistic probability plots for some independent variables that have complex or similar distributions



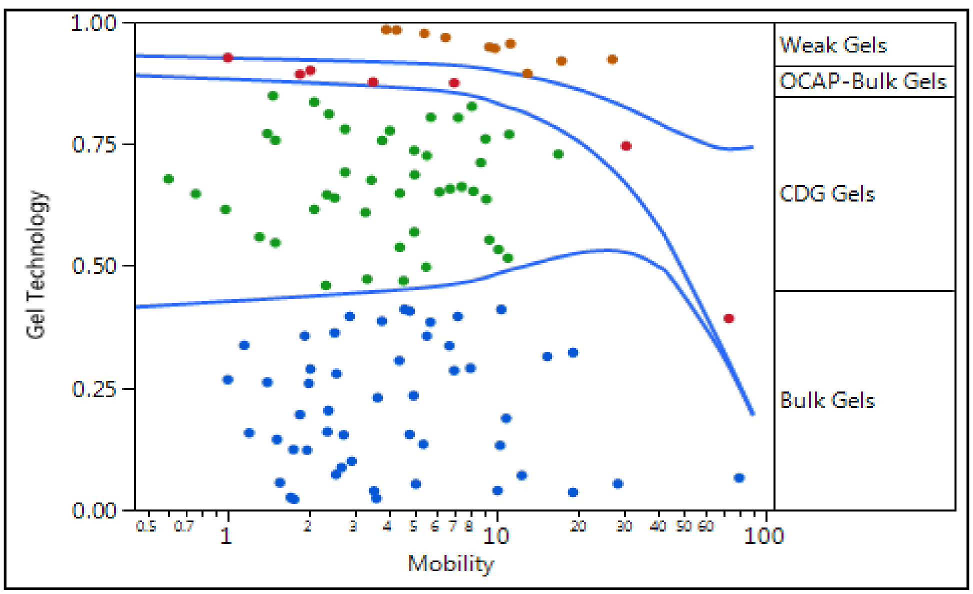


Figure 9. Logistic probability plots for some independent variables that have complex or similar distributions (Cont'd)

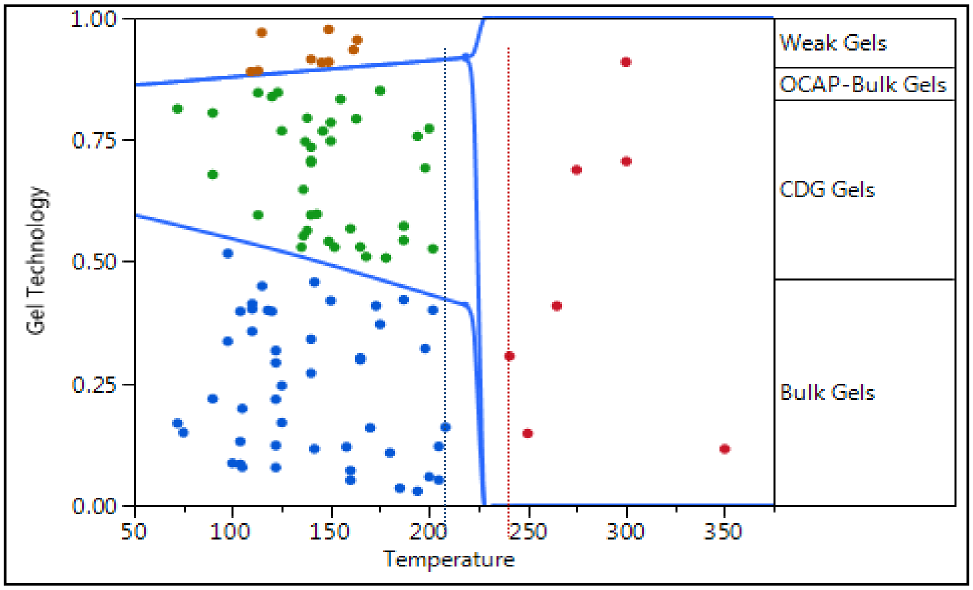


Figure 10. Logistic probability plot for reservoir temperature shows the approximations of the validity limits of MCAP and OCAP gels

This figure shows that is movement happens at 170°F and 165°F for naturally fractured and unconsolidated formations, respectively. This restriction in temperature intervals for these formation types is attributed to the wide gap in the data for unconsolidated formations and absence of applications of OCAP-BGs in naturally fractured reservoirs. The problem was solved by treating temperature as a binary categorical variable with classes LT and HT depending on whether the value of temperature is less or greater than 210°F.

Logistic Regression Stability and Separation. Because of the existence of small population (111 projects) and 13 candidate predictors, a special attention was paid to two logistic regression issues. First, inclusion of a large number of independent variables results in over-fitted models that have numerically unstable estimates for the coefficients.

Secondly, there is a potential of complete or quasi separation of logistic regression as some gel technologies have zero counts for some categories of lithology, formation, and IOR/EOR process (Figure 6).

The problem of existence of separable data (no overlap in distributions) is that coefficients of these categories will be as large as it can be infinity and the maximum likelihood estimates fail to converge. Examples for these zero counts categories are absence of CDGs projects in carbonate reservoir, CDGs in CO_2 flooding, and WGs in naturally fractured reservoirs.

Treatment of Independent Variables. In addition to discretization of temperature, we recategorized IOR/EOR process based on the following explanation. This aspect has been adopted in the conventional screening guidelines to ensure compatibility of polymer gels with the drive-fluids of different EOR methods. For example, for oilfields that produce by means of CO_2 flooding, conformance problems have been treated only by BGs. This implies that in-depth fluid diversion technologies like CDGs and WGs are not candidates for these reservoirs. Another example is that in case of steam injection, only OCAP-BGs can be used due to temperature limitations of other gel systems. However, there are no preferences showed by polymer gels toward water flooding in favor of polymer flooding and vice versa. In other words, these two recovery processes have equal chances in term of applicability of gel technology. This point was illustrated by one BG history case where the developed models correctly predicted gel technology (IOR/EOR process is waterflooding); however, changing IOR/EOR process to polymer flooding resulted in bad prediction (CDGs) as shown by Figure 12. Therefore, we modified data of this categorical variable by combining water and polymer floodings into one class to solve this problem.

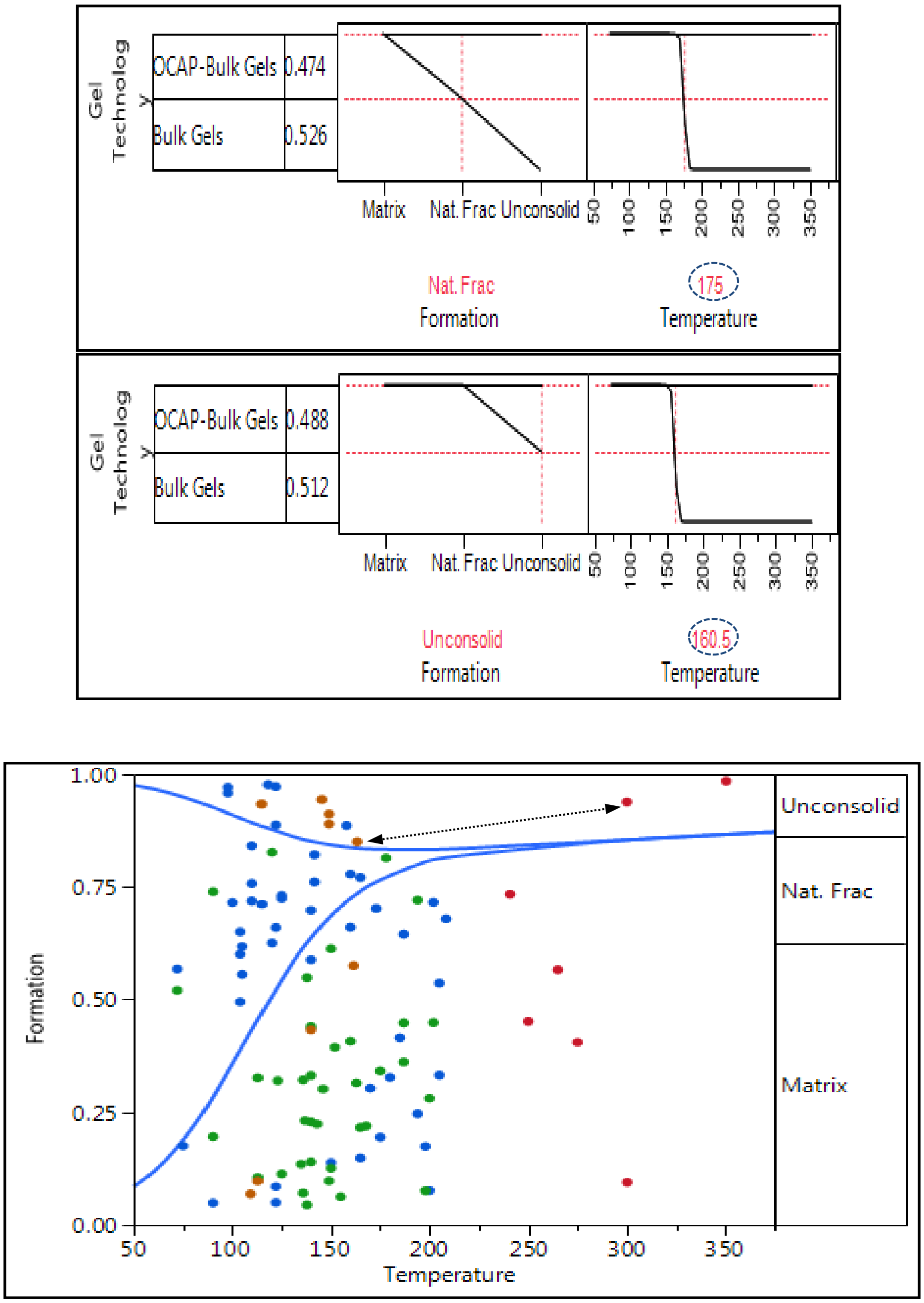


Figure 11. Prediction profiler plots and logistic probability plot for reservoir temperature

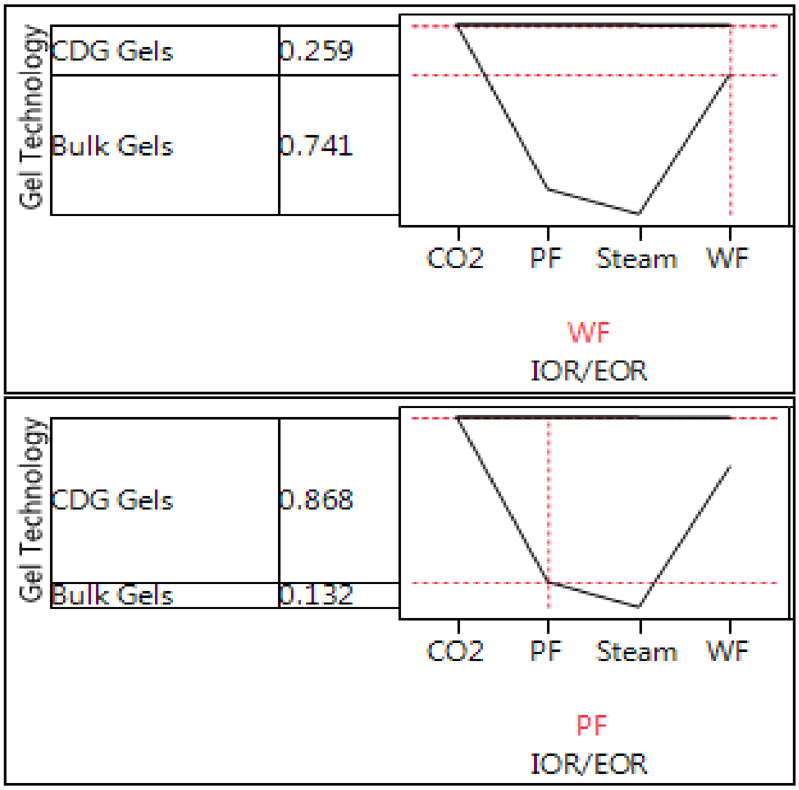


Figure 12. Profiler plots show prediction results of one BG history case before the treatment of IOR/EOR independent variable

Model Construction and Estimation

JMP® software was utilized to develop three logistic classification models with a variant for each model to meet certain application trends. Initially, the data of all treating agents were used to build a general classification model for gel technologies. However, considering the presence of only seven case histories for OCAP-BGs in the database, it was expected that this model would have some cons as there are few data points for this gel system to train the classifier. Despite the extensive model monitoring and treatment of the expected issues, there were concerns about potentially undiscovered or hidden issues relate to the scope of training data. Also, in order to allow a constructed model to catch as much as possible of the informative content of the data, we eliminated OCAP-BGs to build another multinomial logistic model.

Finally, WGs are exclusively applied in Chinese oilfields due to availability and extensive experience with polymer floodings. Hence, a third binary model was constructed using the data of BGs and CDGs to alleviate this regional trend of application and to obtain specialized model for these systems. In this study, it has been referred to these three models as G4, G3, G2, where the digits indicate the number of the considered gel technologies in each model.

We noticed some trends in the application of some gel technologies that need to be considered in the development of the advanced criteria. These trends are related to gel treatments timing (early vs. late) or objective (proactive vs. reactive), which in this study were indicated by three variables that are pre-treatment water cut, flood life time, and to less degree oil recovery factor. While CDGs had been extensively applied at early stages of the flood life in many oilfields (Diaz et al. 2008; Lantz and North 2014), their recent applications in El Tordillo, Dina Cretaceous, Loma Alta Sur, Daqing, and others were at quite high water cuts and long injection durations (Aldhaheri et al. 2016a). Contrarily, BGs and WGs started to be applied at very early stages of EOR floodings as in case of SACROC unit (Pipes and Schoeling, 2014) and Luda LD10-1 (Lu et al. 2010; Kuiqian et al. 2015) oilfields for example. To meet these new trends, a variant model was constructed for each of the aforementioned classifiers (G4, G3, and G2) in which the gel treatment timing parameters were eliminated during the construction phase. These variant models have been termed as G4.1, G3.1, and G2.1 to distinguish them from the main models.

On the basis of the criteria discussed above and in the previous section, 11 predictors were generally selected to construct the three classification models. Lithology, formation type, IOR/EOR process, porosity, average permeability, DPc, net thickness, depth, oil viscosity, water cut, and recovery factor were included in all models. Reservoir temperature was statistically significant and has been considered only in the first model (G4); thus, this model involved 12 regressors. Screening results of these multinomial and binary logistic regression models are the probabilities of the considered gel technologies estimated based on the historical field data and are expressed as percentages. To facilitate the utilization of the developed models, Excel spreadsheets were constructed that attached to this paper and can be also downloaded from the authors' Researchgate account with title of "Advanced Polymer Gels Selection Tools".

JMP® offers an effect-summary report that examines the variable importance across multiple responses based on what so-called LogWorth (-log (p-value)) at 1% significance level. In this study, a variable with a LogWorth value of 1.3 that is corresponding to 5% significance has been considered as influential predictor. Figure 13 compares the effect-summary reports of the three developed models and illustrates the following general tendencies:

1- Five variables (porosity, net thickness, oil viscosity, water cut, and recovery factor) are significant according to all variable selection criteria and in all developed models.
2- Average permeability significance decreases as the number of considered systems is reduced, where it is very discriminating in G4 and G3 models; however, it has very weak predictivity in the G2 model. Contrarily, depth has exactly the opposite

trends of permeability where its importance increases with the reduction in number of gel technologies. It is important to note that depth has weak univariate discriminating powers according to R^2.

3- Reservoir temperature and IOR/EOR process appeared important only in the G4 model due to presence of the OCAP-BGs technology. In other two models, it expected that these variables have weak selectivity as the considered gel technologies in these models are applied approximately at same temperature ranges and in same IOR/EOR floods. Furthermore, recategorization (combining water and polymer floodings) and zero counts for CO_2 floodings with respect to CDGs and WGs substantially reduce predictive power of this reservoir operational parameter.

4- Lithology, formation type, and DPc are never significant for any of the developed models despite the strong univariate predictive powers of first two properties. Further discussion of this trend is presented in the next paragraphs.

5- While it is expected that DPc has a role in capturing the strengths of the drive-fluid channeling, and thus, in the selection of gel systems. It seems that porosity and permeability have indicated this characteristic according to their significance levels.

JMP® also offers a variable-importance report which calculates indices that measure the importance of factors in a model in a way that is independent of the model type and fitting method. The fitted model is used only in calculating predicted values. The method estimates the variability in the predicted response based on a range of

Effect Summary: Model (G4)

Variable	LogWorth
Permeability	45.438
IOR/EOR2	37.572
WC	3.890
Thickness	3.756
RF	3.419
Porosity	3.032
Viscosity	2.682
Depth	2.456
Formation	0.928
DPc	0.530
Lithology	0.000
TempCode	0.000

Variable Importance: Model (G4)

Variable	Total Effect
Lithology	0.181
IOR/EOR2	0.18
Formation	0.179
WC	0.163
RF	0.094
Temperature	0.058
Porosity	0.057
Permeability	0.056
Depth	0.056
Thickness	0.046
DPc	0.04
Viscosity	0.038

Effect Summary: Model (G3)

Variable	LogWorth
Permeability	3.907
WC	3.228
RF	2.585
Thickness	1.895
Viscosity	1.842
Porosity	1.677
Depth	1.376
IOR/EOR2	0.880
Formation	0.862
DPc	0.718
Lithology	0.171

Variable Importance: Model (G3)

Variable	Total Effect
Lithology	0.288
WC	0.269
Formation	0.237
RF	0.172
Viscosity	0.165
Porosity	0.165
IOR/EOR2	0.161
Thickness	0.082
DPc	0.06
Depth	0.059
Permeability	0.05

Effect Summary: Model (G2)

Variable	LogWorth
WC	3.079
Depth	2.356
Viscosity	2.265
Thickness	1.799
RF	1.545
Porosity	1.376
DPc	0.857
IOR/EOR2	0.689
Lithology	0.403
Permeability	0.356
Formation	0.137

Variable Importance: Model (G2)

Variable	Total Effect
WC	0.34
Lithology	0.311
IOR/EOR2	0.179
Viscosity	0.161
Porosity	0.15
Formation	0.116
RF	0.094
Depth	0.089
Thickness	0.052
DPc	0.046
Permeability	0.026

Figure 13. Comparisons of variable effect (left) and importance (right) summaries for the logistic classification models

variation for each factor. If variation in the factor causes high variability in the response, then that effect is important relative to the model (JMP 2015).

In this study, the independent resampled inputs approach was selected to evaluate the importance of independent variables. In this method, for each factor, Monte Carlo samples are obtained by resampling its set of observed values. Variable-importance reports shown in Figure 13 confirm the importance of some variables that considered influential based on the statistical significance tests. On the other hand, these reports reveal that the never or rare significant predictors such as lithology, formation type and IOR/EOR process based on the effect-summary reports have substantial contributions to the predicted gel technology. Further discussion of this trend is presented in the next paragraphs.

Model Validation and Results Discussion

A logistic classifier should meet three main requirements during the validation phase: stability, readability, and predictivity. The stability of a logistic model can be inferred by two ways: (a) stable models have p-values below 5% for all estimated coefficients included in the final models; (b) a model is judged as stable if a comprehensive performance measure such as AUC has comparable values for the training and validation samples. During models construction stage, it was noticed that if only continuous predictors are considered, the p-values of the all estimated coefficients in a model are less than 5% for both Wald Chi-square and likelihood ratio tests. However, the inclusion of even only one of the three qualitative aspects (lithology, formation, and IOR/EOR) leads to high standard errors and p-values for Wald test. Yet, likelihood ratio test still shows very low p-values for most regressors except again the aforementioned three aspects as shown in Table 7. This is attributed to the zero counts for some categories of these qualitative variables for certain gel systems. Remarkably, based on the second stability inference way, all developed models and their variants were found to have numerically stable estimates as explained in the next paragraph.

Table 7. Results of likelihood ratio test for the G4 model and a variant (G4.2) without categorical regressors

Effect Likelihood Tests: Model (G4)		
Variable	**L-R ChiSquare**	**Prob>ChiSq**
Lithology	0.0005	1.0000
Formation	10.16009	0.1181
IOR/EOR2	189.8965	<.0001
Porosity	13.96228	0.0009
Permeability	214.176	<.0001
DPc	2.442033	0.2949
TempCode	0.000488	1.0000
Thickness	19.93061	0.0002
Depth	13.60337	0.0035
Viscosity	14.7131	0.0021
WC	20.57639	0.0001
RF	18.30010	0.0004

Effect Likelihood Tests: Model (G4.2)		
Variable	**L-R ChiSquare**	**Prob>ChiSq**
Porosity	14.06424	0.0028
Permeability	19.05327	0.0003
DPc	8.676877	0.0339
TempCode	2.071617	0.5577
Thickness	19.34103	0.0002
Depth	12.71527	0.0053
Viscosity	24.69815	<.0001
WC	15.23990	0.0016
RF	23.16629	<.0001

For discriminating powers, screening results of the main and variant logistic models are in good agreement with the field observations based on all considered performance indicators as shown in Table 8. The proposed approaches correctly predict the proper gel technology in more than 85% (the lowest percent for all models) of the field projects. Also, the comparable values of performance measures for training and validation samples (75% vs. 25%) indicate a high stability for the logistic models in addition to the predictive accuracy. In practice, logistic classification models that have an AUC value in the range of 0.9-1.0 are considered highly accurate. In this study, the minimum AUC obtained is 0.9375 for CDGs in the variant of the G4 model.

Table 8. Performances of Logistic Classification Models for Training and Validation Samples Using Three Global Predictivity Measures

Model	Entropy R^2		Area Under ROC Curve[1]		Correct Classification Rate[2]	
	Training	Validation	Training	Validation	Training	Validation
G4	0.8952	0.7726	0.9957	0.9715	0.9605	0.9200
G4.1	0.7765	0.4814	0.9825	0.9783	0.9342	0.8800
G3	0.7465	0.7306	0.9776	0.9716	0.8857	0.9130
G3.1	0.6619	0.7156	0.9651	0.9769	0.9000	0.8696
G2	0.7273	0.7686	0.9827	0.9722	0.9524	0.9048
G2.1	0.6431	0.6316	0.9643	0.9722	0.8889	0.8571

1-The average of the considered gel technologies in a model, 2-The fraction of correctly predicted projects.

In this study, unsuccessful pilots were also evaluated because it is thought that screening results of these pilots are of special importance as they integrate the depiction of performances of developed models. While G4 model correctly predict the gel system for all 11 unproductive trials, G3 and G2 model correctly classified only 73% of them as shown in the confusion table below which is identical for both models. It is important to note that feasibility of get treatments depends on the correct design and implementation of the remediation in addition to the selection of the best suited treating agent. For example, for some unsuccessful CDG projects, it has been provided that out of the zone injection has determined the success of these pilots which refers to an implementation issue (Mack and Smith, 1994).

Table 9. Confusion Matrix for Results of G3 and G2 Models for Unsuccessful Gel Pilots

Actual Gel Agent	Predicted Gel Agent	
	BGs	CDGs
BGs	2	2
CDGs	1	6

JMP® prediction profiler was used to measure the readability of the models and to monitor how well they follow the conventional screening guidelines. The readability performance of the models is inferred by comparing the expected and estimated variables signs or prediction trends of the responses. Generally, most variables are completely in line with our intuitive expectations as shown in Figure 14; for example, as DPc increases, probabilities of BGs increase while CDG chances decrease.

For monitoring purposes, some rules from the conventional criteria were the basis for the checking of the probabilistic models. For example, only BGs are applicable for carbonate reservoirs and CO_2 floodings, only OCAP-BGs are applicable for steam injection. In this context, it was identified that the G3 and G2 logistic models and their variants completely follow the conventional guidelines as shown in Figure 15.

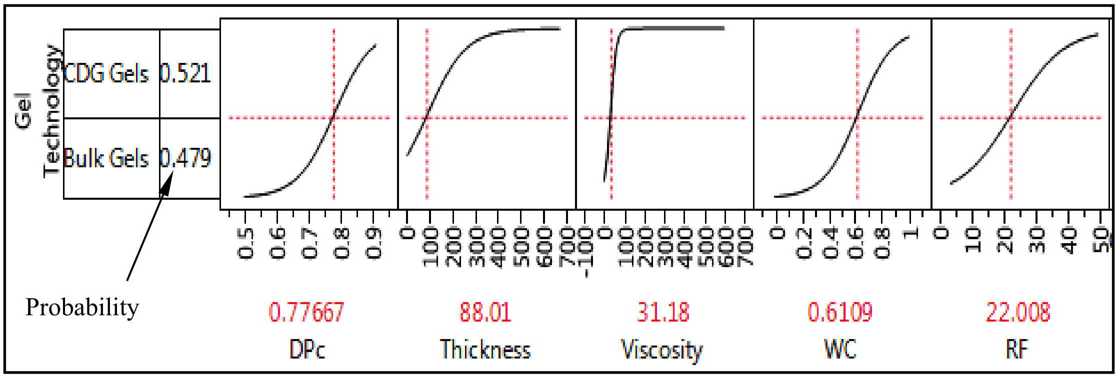


Figure 14. Prediction profiler plot for G2 model shows correct prediction trends for some influential variables

For example, when carbonate selected for the lithology, or CO_2 selected for the IOR/EOR process, these classifiers correctly predict BGs and changing the values of any predictor will not affect this result (horizontal lines). It is important to note that if the probability curve of a variable appears as a horizontal line in this profiler, this means that changing values of this property will not affect screening results for the used values of the predictors. However, for the G4 model, it was indicated that very low water cuts (<6%) reduce the chances of BGs and activate other properties for carbonate reservoirs because these reservoirs were mainly treated at very high water cuts. It important to note that this model still correctly predicts BGs, this trend is observed over very narrow interval (0-6%), and for this model, a variant without water cut was developed.

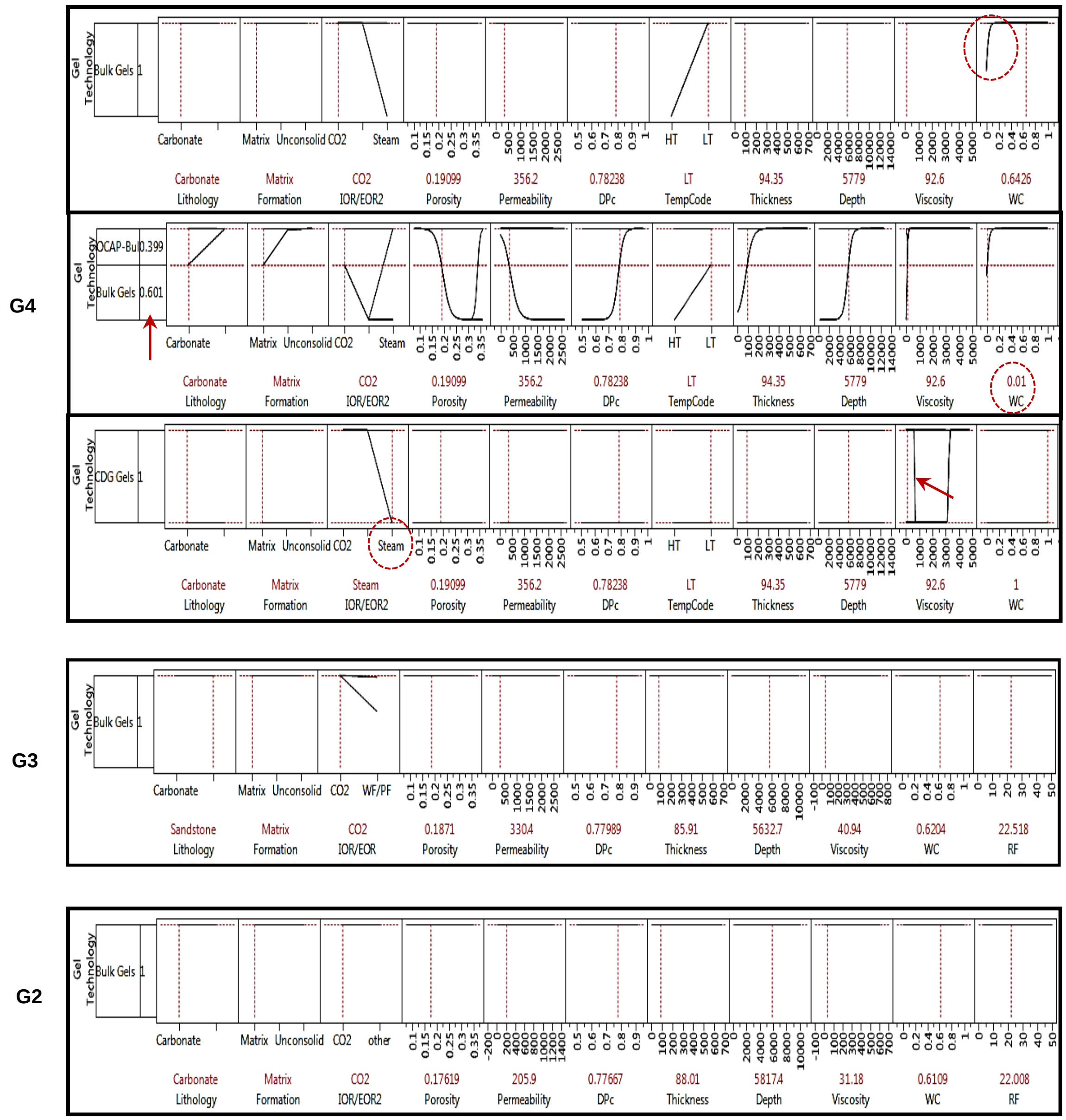


Figure 15. Prediction profiler plots used to monitor performances of logistic models in screening of polymer gels

Furthermore, the profiler was used to check if a model has created a sub rule for a category of the three qualitative predictors (lithology, formation, IOR/EOR process) as a result of the uneven data distribution between their classes. Because classifiers predict what they were trained about, for steam injection method, G4 model incorrectly predicts

CDGs if oil viscosity is less than 700 cp as shown in Figure 16. This sub rule was created because there are only two case histories for steam injection process where OCAP-BGs applied to improve steam sweep in a heavy oil reservoir (700 and 4800 cp), so the classifier tries to stick to these viscosity values. This model tendency was corrected by using the IF/Then rule.

Finally, comparisons of the performances of G4 model and its variant model indicate that variant models estimate lower probabilities for gel technologies than main classifiers. Figure 16 illustrates this observation using a bulk gel history case for which G4 models perfectly predicts the proper gel technology (100%) while its variant (G4.1) estimates a lower probability of 83%.

The investigation of projects that were not correctly classified reveals some important observations about the performances of the models:

- 38% of the mispredicted trials are dual-agent projects where BGs and CDGs or CDGs and WGs were applied to treat injection wells.
- Almost the same projects are misclassified by the models and their variants. Also, models have certain misclassification trend where BGs predicted as CDGs, CDGs as BGs, and WGs as BGs or CDGs when improperly discriminated.
- The most affected gel systems by omitting water cut in the variant models are BGs and CDGs and especially for dual agent projects.
- All misclassified CDG projects had high water cuts in common.

As mentioned earlier, the application of BGs and CDGs is greatly influenced by the timing of gel treatments. G2 model and its variant G2.1 determine applicability of only these two systems; therefore, they are the most suitable classifiers that can be utilized to investigate the effect of treatment timing on the selection of gel technologies. It has been recognized that the variant model G2.1 misclassified some field projects in addition to the same projects that were misidentified by the main model G2. Specifically, G2 model misclassified two BG projects as CDG trials while its variant mispredicted six BG projects. Obviously, the additional four projects (correctly indicated by the main model) were mispredicted by the variant model due to the absence of treatment timing indicator (WC). The situation is same with the CDG projects that were misclassified as BG trials by the variant model G2.1. These observations imply that treatment timing has considerable effects on the selection of gel systems.

Figure 16. A snapshot for the Excel spreadsheet of the G4 logistic model shows screening results for a bulk gel history case

Recall that BGs and CDGs are applied to address strong and weak channeling problems, respectively. This means that above comparisons of mispredicted projects by the main models and by their variants have depicted the development of the drive-fluid channeling (increase) during the flooding life as it illustrated in the following example. For one BG history case with DPc of 0.76, permeability 50 md, net thickness 10 ft, and 93% water cut, the variant model predicted CDGs for this case. This implies that the initial moderate water channeling strengths exist when the problem still considered undeveloped had been exacerbated by the longer than usual water injection in this field (Smith and Larson, 1997). Afterwards, the problem had become well-developed with strong water channeling, and hence, BGs were applied to improve the distribution of injection water. It is important to mention that in this case, channel volume was estimated to be large (> 10^6 bbl) and moderate results with delayed responses were observed for this large volume gel treatment (46700 bbl). This reveals that this model misclassification (CDGs) is definitely correct and it should have been implemented at early stages of the flood life.

It is important to note that treatment timing (not necessarily in term of WC) is just another description of the conformance problem status at the time of remediation. Therefore, the above point was used in another study ((Aldhaheri et al. 2016b) to support other observations used to verify that the problem development status (whether it undeveloped or developed) is one of the influential parameters in gel selection process.

Conclusions

For injection well gel technologies, a machine-learning-based screening approach was developed by using the logistic regression technique and the worldwide field projects. A comprehensive research was performed to identify the most suitable supervised classification technique that can handle the variety of parameters utilized in the rating of polymer gels. These parameters were undergone an exhaustive testing to provide better understanding and to select the most discriminating variables using several strategies and criteria. Three probabilistic models with three variants were constructed to meet the regional and recent application trends of gel systems. The predictivity of the proposed classifiers was demonstrated using three global performance measures and visually monitored using the prediction profiler. Some tendencies were identified by comparing results of the main and variant models, and by investigation of the misclassified projects.

Analyses indicate that data gaps plays a vital role in determining how well the developed models stick to the screening rules and provide correct predictions. For logistic regression, it is important to examine data distributions against all classes of the qualitative variable to identify any deviation from the application guidelines. The zero counts of gel technologies for some categories of the qualitative variable made these predictors seem insignificant according to some statistical test. However, variable-importance reports showed substantial contributions for these qualitative variables in the prediction of gel systems. Five variables appeared to be very discriminating features including porosity, net thickness, oil viscosity, water cut and recovery factor. Probabilities of BGs and WGs increase in favor of CDGs as DPc, net thickness, oil viscosity, water cut, and oil recovery factor increase. Comparisons of the results of the classification models and their variants signalized the increasing nature of the severity of drive-fluid channeling with the continuation of injection operations. They also indicated the importance of identifying the development status of the conformance problem in the gel selection process. Finally, the developed methodology proved that the logistic regression is an efficient technique to handle EOR screening that characterized by complex data patterns and large number of the influential parameters.

In addition to being the first advanced screening criteria for polymer gels, the most distinctive features of the developed methodology are (a) its capability to predict the most technically applicable gel technology for undiagnosed injection patterns, (b) it can rank the potential treating agents for a specified injection pattern via the predicted probability, (c) it manipulates the regional tendencies and new developments in the application polymer gels, (d) it the first logistic regression-based EOR screening criteria, and (e) it is available in the public domain. The proposed logistic probability models can assist reservoir engineers in preliminary assessment of the potential treating agent for specific injection patterns. However, selection should be confirmed by the adequate characterization of the conformance problems.

Nomenclature

AUC =	Area Under ROC Curve
BGs =	Bulk Gels
CDGs =	Colloidal Dispersion Gels
CO_2 =	Carbon-dioxide flooding
CV =	Coefficient of variation
D =	Reservoir depth, ft
FL =	Flood life, year

DPc =	Dykstra-Parsons coefficient, fraction
G4, 3, 2 =	Main logistic classification models
G4.1, 3.1, 2.1 =	Variant models
h =	Average net pay thickness, ft
k =	Permeability, md
M =	Mobility ratio
Mat. =	Matrix-rock
NF. =	Naturally fractured reservoirs
IQR =	Interquartile range
PF =	Polymer flooding
RF =	Recovery factor, %
ROC =	Receiver Operating Characteristics Curve
Sal. =	Salinity, ppm
St. Dev =	Standard Deviation
Steam =	Steam injection
T =	Temperature, °F
Uncon. =	Unconsolidated formation
WC =	Water cut, %
WF =	Waterflooding
WGs =	Weak Gels
Φ =	Porosity, %
μ =	Oil viscosity, cp
min =	Minimum
max =	Maximum

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SECTION

3. CONCLUSIONS AND RECOMMENDATIONS

Conformance improvement by polymer gels continues to gain momentum in the field of water management in mature oilfields. Polymer gels can effectively mitigate water production and enhance the sweep efficiency of IOR/EOR floodings. Thus, they extend the productive lives of mature oilfields by recovering the previously bypassed oil reserves. The selection process of gel technologies involves a high degree of sophistication due to many geological and technical reasons. Remarkably, the qualitative nature of conformance problem characterization and the independent evaluations of gel systems are the main contributors in this complexity.

In this dissertation, a comprehensive review for gel field projects was conducted to establish complete applicability guidelines for gel technologies based on their field applications in injection wells. An integrated systematic methodology was developed to determine the applicability of three injection well gel technologies including bulk gels, colloidal dispersion gels, and weak gels. Comparative analysis, univariate statistical analysis, and logistic regression technique were utilized to develop a standardized selection system, conventional screening criteria, and advanced screening models for the gel systems under evaluation.

The overall conclusions can be summarized as follows:

1. Conformance problems are often qualitatively characterized using different problem descriptions in terms of reservoir lithology and formation type. This

evaluation nature has imposed several problems in the context of rating problems and solutions.

2. Gel technologies have been exclusively chosen based on the drive-fluid channeling strength and 13 different reservoir properties and operational and diagnosing indicators were utilized in the evaluation of this characteristic.
3. Particularly for clastic reservoirs, gel selection statements that employed reservoir lithology, formation type, or permeability variation are inadequate to describe the strength of the drive-fluid connectivity or to use as efficient system for chemical agent selection. They should be used only as starting point in the matching of conformance problems and gel systems.
4. Gel technology selection is a two-step process that starts by matching the four qualitative properties of problems and solutions technical specifications. The initial candidate gel technology is then confirmed by the numerical screening criteria to ensure compatibilities with reservoir and injected fluids.
5. The drive-fluid channeling, volume of offending zones, problem development status, existence of cross-flow, and nature of the required solution are the most influential aspects in the matching step of the selection process of a conformance agent.
6. In addition to crossflow, the presence of high oil saturations or unswept regions in the offending zones requires the application of the flood-size treating technologies that combine displacement and diversion mechanisms.
7. The selection and design of chemical systems for a certain conformance problem greatly depend on the timing of the conformance treatment in the flood life.

8. BGs are solutions for conformance problems that are direct communication (>0.5), small volume (< 10^6 barrels), and involve high oil saturations only in the low capacity zones of a reservoir.
9. CDGs are applicable for conformance issues that have weak communication (<0.5), reservoir scale offending zones, and high oil saturations in both high and low permeability zones.
10. Weak gels are best suited for the situations that are similar to those of BGs when they treat indirect channeling strengths for profile modification purpose. Or similar to CDG conditions when they treat direct channeling as in-depth fluid diversion agents.
11. The Lithology, formation type, and EOR process have great effects on the data of some reservoir properties. For screening purposes, mixed data sets should be analyzed according to these affecting aspects. Otherwise, they would falsify where polymer gels have actually been applied.
12. Based on logistic regression technique, five variables appeared to be very discriminating features between gel systems including porosity, net thickness, oil viscosity, water cut and recovery factor.
13. The Probabilities of BGs and WGs increase in favor of CDGs as DPc, net thickness, oil viscosity, water cut, and oil recovery factor increase.
14. Comparisons of the results of the classification models and their variants signalized the increasing nature of the severity of drive-fluid channeling with the continuation of injection operations. They also indicated the importance of

identifying the development status of the conformance problem in the gel selection process.

Further research is needed to develop an integrated numerical characterization system for drive-fluid channeling that has the ability to rate conformance problems and polymer gels. The easiness of the practical implementation is the ruling feature of any suggested methodology. Such system should also take into considerations all aspects of offending zones like net thickness, permeability contrast, and channel shape or configuration. In addition, there is an urgent need to develop accurate estimation methodologies for offending zone volumes especially in the cases of naturally fractured formations. Furthermore, it is advisable to include the polymer gels applications in the Oil and Gas Journal survey of EOR methods.

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