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EOR Screening Methods Assisted by Digital Rock Analysis: A Step Forward

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Abstract

The screening of chemical EOR technologies for a Colombian field was performed using two different screening tools (weighting averages and artificial intelligence). The Alkali-Surfactant-Polymer (ASP) pilot results were compared with the initial screening studies identifying some weaknesses that are addressed in this paper. Additionally, the use of Lattice Boltzmann pore-scale flow simulation approach to support EOR screening studies is also presented.

The screening study was developed using the same input data (e.g. pressure, temperature, porosity, permeability, oil gravity, and viscosity). Screening results and potential reservoir analogs identified using both systems were compared, including the evaluation of the geological parameters that are normally missing in most of screening studies. The results are compared with the ASP pilot performance to validate the effectiveness of conventional screening studies overlooking geologic information. In addition, the results were also confirmed evaluating ASP field cases reported in the literature. Finally, the use of digital rock analysis using micro CT scan images to support ongoing screening results is presented.

Screening results obtained using different screening tools were similar identifying the EOR recovery process (e.g. Chemical EOR). However, the screening results excluding the evaluation of geological parameters such as rock cementation (e.g. sandstone formations with carbonate cement) did not prevent the selection of ASP flooding as an EOR recovery process for the field under study. This was confirmed with the severe scaling problems observed during the ASP pilot test implemented in Colombia as well in Canadian ASP floods. This paper describes the main steps for conducting robust EOR screening studies, including the use of Lattice Boltzmann pore-scale flow simulation to evaluate preliminary performance of oil recovery processes (e.g. waterflooding, polymer and surfactant injection) that contributes to field evaluations and experimental lab design.

The proposed screening approach will contribute identifying the technical and economic EOR potential (from exploratory appraisal to mature field rejuvenation) under conditions of limited information and time constraints.

Introduction

Enhanced-Oil Recovery (EOR) evaluations focused on asset acquisition, increase oil recovery and oil reserves involve a combination of complex decisions, using different data sources. Generally, these evaluations begin with screening studies to identify the potential of EOR methods in a given reservoir. EOR screening techniques have been widely documented in the literature. Most EOR screening techniques are based on conventional (go-no-go) and advanced approaches or a combination of both (Alvarado et al., 2002; Khojastehmehr et al., 2019; Siena et al., 2016; Taber et al., 1997; Zhang et al., 2019). However, very few screening methodologies includes the evaluation of geologic variables (Henson et al., 2002; Manrique et al., 2009). The evaluation of geologic parameters such as depositional environment, structure, petrophysical properties incluing thin section interpretations could not only be valuable for a better evaluation of the screening results to select an EOR method, but also for possible evaluations of reservoir analogs and reserve estimates (Alvarado and Manrique, 2010; PRMS, 2018).

This study aims to present an example that highlights the importance of the geologic screening when considering the use of Alkali-Surfactant-Polymer (ASP) and the use of Lattice Boltzmann pore-scale flow simulation approach to support EOR screening studies. To demonstrate the importante of geological variables in EOR screening studies, the following approach was considered:

- EOR screening results were compared using two different approaches for a Colombian Field with an ASP pilot test reporting severe scale formation (Dueñas et al., 2018, Izadi et al., 2018).
- ASP results of two Canadian field project also reporting severe scaling problems will be discussed (McInnis et al., 2013; Hunter et al., 2013).

The second and last objective of this study describes the use of of digital rock analysis using computed micro tomography (micro CT) images to support ongoing screening, laboratory and simulation studies in Ecopetrol. The use of the Lattice Boltzmann pore-scale flow simulation approach to support EOR studies is gaining greater interest in the oil and gas community. This methodology can be used to evaluate waterflooding, gas flooding and several EOR methods in small fractions of rock (< 1cm^3) (Fager et al., 2019; Jerauld et al., 2017; Sun et al, 2018).

Importance of Geologic Screening: ASP Case Studies

Comparison of Screening Methods

The comparison of screening methods was performed using the same input reservoir parameters (e.g. pressure, temperature, porosity, permeability, oil gravity, and viscosity) of a Colombian sandstone reservoir with an ASP pilot that began during the 4Q of 2013 (Table 1).

Table 1—Main reservoir data used for the comparison of EOR screening methods.

Temperature (°F)	Depth (ft.)	Porosity Range (%)	Perm. Range (mD)	Actual Pressure (psi)[a]	Oil Gravity (°API)	Oil Viscosity (cP)
125	2,630	9 - 18	50 - 2,000	700	25.5	7

a. Pressure when the ASP project start.

The screening methods used are based on weighting averages (EcoEOR), an internal software developed by Ecopetrol (Trujillo et al., 2010) and an advanced screening based on space reduction techniques and machine learning algorithms (Alvarado et al., 2002; Alvarado and Manrique, 2010). Although both systems have different characteristics, the comparison of the results will be based on the chemical EOR projects - cEOR ("projects with similar reservoir properties") identified in the databases of each of the screening tools. Results obtained through the advanced EOR screening show that the cases run for the reservois under study were located in cluster 5 of the "Expert Map", characteristic of medium and heavy oil reservoir typology. Reprocessing cluster 5 confirms the applicability of cEOR methods (Figure 1). This screening was developed using all reservoir variables shown in Table 1 but reservoir depth. The cases highlighted with red dashed represent the sensitivity scenarios for a different combination of reservoir porosity and permeability. It should be noted that all cases evaluated are close to several cEOR projects and only some of them are identified (ASP projects in Instow and West Khiel, and CDG projcets in Daqing and El Tordillo). It is worth mentioning that Daqing also reports an ASP project, but it was not included in this example. However, the interpretation of the screening results suggests the applicability of cEOR, specifically ASP for the case under evaluation.

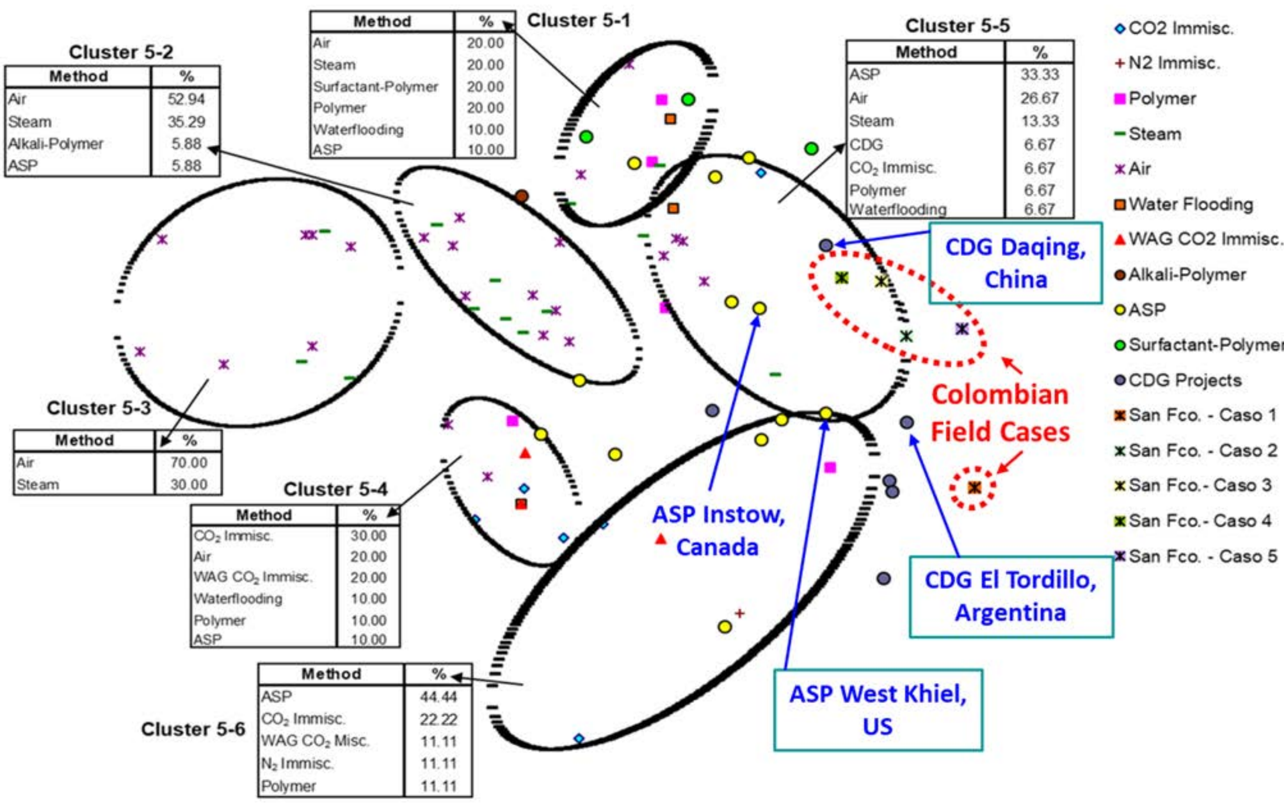

Figure 1—Expert map identifying some possible cEOR projects with similar properties to the Colombian reservoir under study.

On the other hand, the screening results with EcoEOR also ranked first polymer and surfactant recovery processes as the possible cEOR methods to be considered after waterflooding. In addition to the reservoir variables presented in Table 1, this screening results also included the reservoir lithology (sandstone), depostional environment (marine transitional), net pay and current oil saturation (timing to start the cEOR). Table 2 presents a summary of the screening results and identification of fields that report recovery processes based on polymer and/or surfactant with similar reservoir properties to the Colombian case under study. Other EOR processes that partially meet the technical criteria (Scoring < 1) include in situ combustion (High Pressure Air injection or HPAI) and CO_2 flooding (immiscible and miscible) among other gases at immiscible conditions. However, due to the lack of natural gas and CO_2 availability and the potential high capital expenditures (CAPEX) associated with N_2 injection, the use of cEOR methods was justified. Additionally, and based on empirical correlations to estimate the minimum miscibility pressures, the expected incremental oil recoveries from immiscible N_2 injection may not justify this reservoir development plan.

Table 2—Summary of the EOR screening results and possible analog identification using EcoEOR.

EOR Screening Results			Possible Analog Identification with cEOR		
Recovery Process	Score	Technical Criteria	Recovery Process	Score (Rank)	Field (Country)
Polymer flooding (PF)	1	Meet	PF	68.96 (1)	West Khiel (U.S.)
Surfactant injection (a)	1	Meet	PF	68.90 (2)	Rapdan Unit (Canada)
In Situ Combustion	0.94	Partially Meet	PF & ASP	68.57 (3)	Daqing (China)
Immisc./Miscible CO_2	0.89	Partially Meet	SP	67.62 (7)	Bob Slaugther (U.S.)
Other gas injection	< 0.85	Partially Meet	SP	66.56 (11)	Ranger (U.S.)
Other thermal methods	< 0.67	Does no Meet	PF / CDG (b)	64.98 (16)	El Tordillo (Argentina)

(a) Surfactant-Polymer or Micellar Polymer (SP) and Alkali-Surfactant-Polymer (ASP).
(b) Colloidal Dispersion Gels (CDG).

Regarding the fields with similar reservoir properties ("possible analogs") to the Colombian case study with documented polymer and/or surfactant-based projects, they were identified assuming an equally weight distribution (9.09) for the eleven parameters. Among the top sixteen (16) polymer and/or surfactant-based projects identified in the EcoEOR database, at least three (3) were projects also identified using the advanced EOR screening (Figure 1 and Table 2).

Based on the results using two completely different screening tools, it can be concluded that EOR screening methodologies are very useful to perform a quick assessment of a given reservoir or portfolio of reservoirs regardless the screening approach used. However, screening studies often do not include a more detailed assessment of different geological variables ("geologic screening"). In general, screening studies can help justify conducting laboratory evaluations of EOR methods identified, specifically cEOR in this case study.

For the Colombian case under evaluation, comprehensive laboratory and simulation studies were performed to evaluate the technical and economic feasibility of ASP flooding. The results of these studies supported the evaluation of the technology at pilot scale by the end of 2013 (Dueñas et al., 2018). Although a good oil response was observed, severe precipitation of calcium carbonate sscales were also reported (Dueñas et al., 2018; Izadi et al., 2018). Subsequently, a detailed assessment was required to potentially explain the reasons of the severe scaling trends observed during the ASP flood using sodium carbonate (Na_2CO_3). As indicated above, the reservoir under study is a sandstone formation with a depositional environment described as "Marine Transitional". These type of deposits are those that are transition between continental and marine environments and can lead to sandstone formations with carbonate cements (Scholle and Ulmer-Scholle, 1978). For this case study, Caballos Fm. is a sandstone formation with carbonate cement and where the dissolution of fragments of volcanic rock, feldspar, calcite and dolomites cement contributed significantly to the reservoir porosity and permeability (CoreLab, 1994; Duarte et al., 2018; NLErco, 1986; Sneider 1988 and 1990). The latter may explain the scale formation in offset wells due to the effects of dissolution and reprecipitation of carbonatic cement during the injection of the ASP slug (pH ≈ 11) using high concentrations (1.75 wt%) of Na_2CO_3. This example suggests that EOR screening methods, experimental protocols and numerical simulation studies shows some weaknesses that could be similar to those observed in the case study described in the next section.

Example of Scale Formation in Canadian ASP Floods

The Warner (Mannville B Taber South) and Crowsnest (Glauconite K Taber) pools are two cases reporting ASP floods since mid-2000. Both pools are sandstone formations (Quartz content between 73% and 81%) and the injected ASP systems use sodium hydroxide (NaOH) as the alkaline agent. Table 3 summarizes average properties of Crowsnest and Warner pools (Delamaide et al., 2014; Hunter et al., 2013; Lozanski and Martin, 1970; McInnis et al., 2013; Shaw and Stright Jr., 1977).

Table 3—Average reservoir properties of Crowsnest and Warner pools, Canada.

Reservoir Property	Warner	Crowsnest
Temperature, °C (°F)	35 (95)	34 (93)
Avg. Porosity, %	24	23
Avg. Permeability, mD	>1,000	1,517
Net Thickness, m (ft.)	7.1 (23)	6.5 (21)
Oil Gravity (°API)	19.1	18 - 19
Live Oil Viscosity, cP	119	85
Res. Pressure (Initial/Actual), psi	1,443 / 1,305	1,474 / 1,392
Bubble Point Pressure (psi)	668	625

Both ASP floods reported severe scale deposition in production wells and production facilities. It was reported that at the early stages of the flood the initial scales were predominantly calcium carbonate but as the flood progressed the scales changed to amorphous silicate (Hunter et al., 2013). The Warner ASP flood showed better incremental oil production than Crowsnest. However, scale formation and operational problems had a negative impact on oil production and project economics (Hunter et al., 2013; McInnis et al., 2013). Reported annual costs related to well interventions in the Warner project more than doubled due to an 80% increase in scale inhibition programs (Hunter et al., 2013). Although the number of well services decreased after implementing calcite and silicate scale inhibition programs, the increase in operational expenditures (OPEX) is expected to have a negative impact on project economics. Despite the lessons learned in the Warner ASP flood, the scaling tendencies in Crowsnest project were challenge due to the difficulties faced in understanding appropriate scale inhibition strategies.

Similar to the Colombian case study discussed in the previous section, the ASP floods of Warner and Crowsnest suggest some weaknesses regarding the geologic information evaluated, specifically rock mineralogy. Both fields are producing from the same Glauconite Fm. (Upper Mannville Group) and, as described above, these sandstone formations report that quartz content can vary from 73% to 81%. The latter suggests that at least 19% to 27% of the rock composition consist of different reactive minerals (i.e. carbonates, clays) that can react negatively with alkaline solutions, some examples includes:

- The reservoir rock was described as a fined-grained sand containing significant amounts of glauconite and pyrite (Shaw And Stright, 1977).
- The presence of volcanic fragments, feldspars and detritic dolomite in this glauconitic formation was also reported (Young and Doig, 1986).
- High quality reservoir reporting the presence of distinct volcanic and feldespathic composition (Hayes et al., 2008).

Based on the mineral composition of the Upper Mannville Group, the presence of dolomite ($CaMg(CO_3)_2$), pyrite (FeS_2) and glauconite ($[(K, Na)(Fe^{3+}, Al, Mg)_2(Si, Al)_4O_{10}(OH)_2]$) can lead to the dissolution and precipitation of carbonate/silicate scales and other secondary phases under high pH (>10) conditions existing during the injection of the ASP slug with NaOH (Arensdorf et al., 2011). Silicate scales were also reported in Daqing ASP flood using NaOH as an alkaline agent (Qing et al., 2002).

Summary Discussions

The previous case studies represent an example of the importance of geologic screening. In both case studies presented, it was clear the applicability of surfactant-based methods (i.e. SP or ASP) but overlooking geologic information may influence a different decision from the early stages of the EOR screening evaluations. However, neither current laboratory protocols nor numerical simulation studies using academic or commercial simulators were able to identify or predict scale tendencies. Therefore, there is a need for improvement in both areas, especially for alkaline-based EOR methods.

On the other hand, it is common that the sanction of chemical EOR (cEOR) projects are strongly influenced by CAPEX and the main advantage of ASP over SP in this scenario is the reduction of surfactant concentration (upfront costs). However, the CAPEX driven approach of cEOR projects can negatively affect a given technology by overlooking the impact of injected fluids it will have on OPEX (i.e. well productivity, crude oil separation, surface facilities) and overall project economics.

Some lessons learned from the experience of these case studies include but are not limited to:

- Do not overlook geologic information from the screening of candidates for cEOR, specially, AP or ASP floods. The review of despositional environment and thin sections, among others, can contribute identify the possible presence of highly reactive minerals under alkaline conditions that can guide the decision-making process.
- XRD (X-Ray Diffraction) data might not be enough to characterize rock mineralogy, especially for minerals in low quantities or traces (less than 2% in the total rock). Therefore, SEM-EDS (Scanning Electron Microscopy Coupled with Energy Dispersive Spectroscopy) to perform rock surface analysis and the elemental composition can contribute to identify minerals not detected by XRD. X-Ray Mapping (EDS combined with elemental maps) and Computed Tomography (CT) scanning are other valuable techniques to support the characterization of reservoir rocks. CT Scanning can potentially identify differences in the densities of the mineral phase that can lead to infer the presence of minerals such as carbonates (i.e cement) and pyrite and other iron mineral phases, among others. In addition, the use of computed rock tomography to perform pore-scale flow based on Lattice Boltzmann simulations is becoming a valuable tool to support cEOR studies from early stages of screening evaluations. However, this will be discussed in the next section of this paper.
- Laboratory protocols needs to be reviewed. Small volumes of rock samples, short residence time and/or volumes of injected chemicals are some of the possible causes that limit the possibility of identifying adverse fluid:rock interactions in current coreflood protocols. For example, shut-in periods during coreflooding have been considered when evaluating ASP floods. This strategy allowed to confirm the reduction in permeability due to mineral dissolution and precipitation of reactive minerals present in the porous media (Kazempour et al., 2013).
- The belief that numerically accurate reservoir dynamic models can overcome the complexities of mineral dissolution and precipitation processes in porous media is unfounded (Zhu, 2009). There are no reliable kinetic data to perform geochemical modeling and to estimate carbonate or silicate scaling. Therefore, and given the existing limitations of numerical models (academic and commercial), it is recommended to carry out a sensitivity analysis taking into account possible productivity losses due to the potential for scale formation (ASP) and/or inverse emulsions (SP or ASP). This scenario can be used to assess the potential impact of deferred oil production and the increase in the number of well services (i.e. workovers, stimulation) on the project economics during the design phase.

Screening Studies Supported by Digital Rock Analysis

Rock CT images have been widely used for several applications (i.e. core description, QA/QC before cutting core plugs, identification of possible mud invasion, etc.). Most recently, the use of high resolution micro-CT images to perform advanced digital rock analysis and pore-scale flow simulation based on Lattice-Boltzmann has recently been documented in the literature (Jerauld, et al., 2017; Schembre-McCabe et al., 2019; Sun et al., 2018; Xu et al., 2018). Digital rock physics combines modern microscopic imaging with pore-scale simulations to predict important rock properties (i.e. capillary pressure, pore size distributions and relative permeability data) and improve the understanding of the physical phenomena occurring at the microscale level. However, the main objective of this study is to evaluate different recovery processes to complement EOR screening studies and also as a possible tool for experimental design.

The Digital Rocks workflow from the the acquisition of high resolution micro-CT images to the single phase (rock properties) and multi-phase flow (i.e waterflooding, gas flooding, water-alternating-gas or WAG) experiments including it interpretation is complex. The worklow and model initialization has been described in the literature for different applications (Jerauld, et al., 2017; Schembre-McCabe et al., 2019; Sun et al., 2018; Xu et al., 2018). Figure 2 summarizes the procedure from taking the rock sample (≈ 0.5 cm^3) and micro-CT (imaging and segmentation) to the analysis pore space (Kx, Ky, and Kz), in this case the absolute permeability for three different samples.

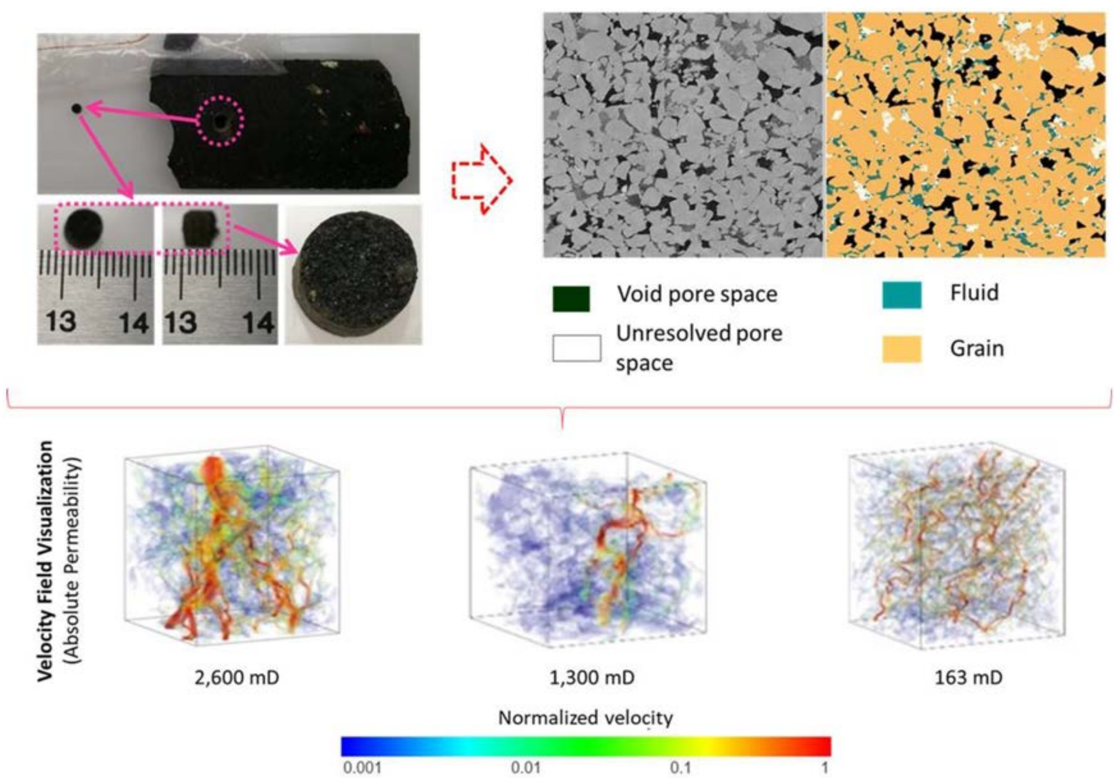

Figure 2—Summary of the basic steps of rock sampling, imaging and pore space analysis before simulating multi-phase flow experiments.

In this study, simulated oil recovery processes include waterflooding at different capillary numbers and wetting conditions. Low salinity waterflooding was also evaluated in this study. At the time this paper was written, the effect of viscosity ratios (i.e. polymer flooding) and immiscible gas/WAG (Water Alternating Gas) on oil recoveries is being investigated. However, these results will not be discussed in this docuement.

First example represent a preliminary exercise comparing different recovery processes in a rock sample from a medium crude oil viscosity reservoir. The sample digitized reported a total porosity of 17% and an absolute permeability of 1,551 mD (Avg. pore size of 40.8 μm). An irreducible water saturation (Swi) of 30.3% was calculated from the fluid saturation distribution. Figure 3 shows the results of the oil recovery process evaluated.

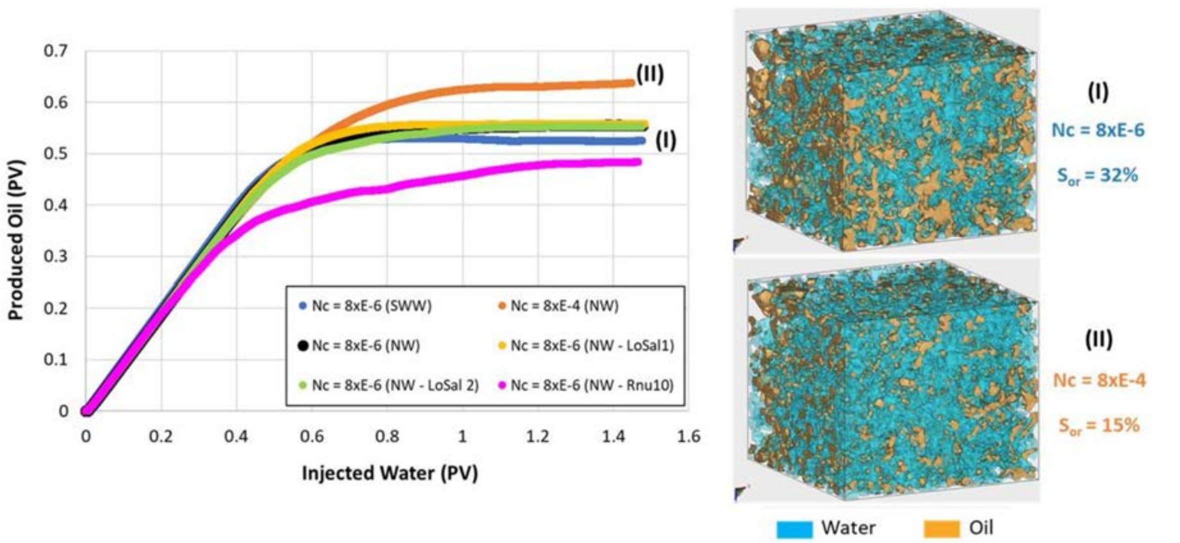

Figure 3—Produced oil vs. injected pore volume (PV) of diferent coreflood experiments based on Lattice-Boltzmann simulation. Figures located at the right shows the final fluid distribution of waterflooding at Nc 8xE-6 (I) and 8xE-4 (II).

Figure 3 shows the cumulative oil recovery obtained from different simulated recovery methods mainly at constant capillary number (Nc = 8xE-6) and wettability conditions (neutral wet - NW). Nc and wettability effects were also evaluated. Final oil recoveries for waterflooding and LoSal cases under the neutral wet (NW) conditions shows similar results. However, final oil recovery for waterflooding under strongly water wet (SWW) conditions was slightly lower than the NW case. Regarding the results of the LoSal cases, similar recoveries compared to waterflooding under NW conditions can be explained due to the low clay content of the reservoir under evaluation. The clay content is less than 10% (total rock) with kaolinite being the most abundant clay in this formation. However, these results will no longer be discussed in this paper until to coreflooding tests are completed to validate the importance of fluid:fluid (i.e. spontaneous emulsification) and fluid:rock interactions at reservoir conditions.

Comparing the effects of Nc (cases I and II identified by the blue an orange curves in Figure 3), there is an increase in the oil produced of approximately 11% of the PV with the reduction of two orders of magnitude of the Nc which can be achieved by reducing the interfacial tension (IFT) or a combination of IFT reduction and an increase in viscosity (i.e. polimeric surfactants). The images to the right of Figure 3 show the final fluid distribution after injecting water at different capillary numbers at neutral wet conditions. It is noticeable the reduction of residual oil saturation (Sor) after reducing the capillary number from 8xE-6 to 8xE-4 (less dark yellow color representing the oil phase in the porous media).

An additional test shown in Figure 3 represents an example of waterflooding under adverse mobility and neutral wet conditions (NW - Rnu10). The case run consists of a displacement with a viscosity ratio of 10 (μo/μw) and clearly shows lower oil production after approximately 0.3 PV of injected water (Magenta curve in Figure 3). The evaluation of the viscosity ratio effects, from adverse mobility waterflooding to favorable mobility ratio (i.e. polymer flooding), using this approach is under evaluation for different reservoir rocks. These sensitivity studies will contribute to understanding the impact of the variation of key parameter (i.e. capillary desaturation, viscosity ratios, wettability, etc.) and their possible combinations in the recovery of oil in different rock types. Therefore, the use of digital methods can contribute to EOR studies (from screening to experimental design of coreflooding) by reducing evaluation times, optimizing the use of reservoir core material and providing valuable information for studies with limited amount of information and time constraints.

On the other hand, over the years, the reliability of the flow parameters measured in coreflooding has been questioned due to its small volume compared to the reservoir scale. Therefore, the proposed digital method that uses smaller rock volumes can generate the same level of scrutiny. To assess the representativeness of pore-scale flow simulation, preliminary experiments were run to demonstrate the applicability of this approach to support screening and laboratory studies (Figure 4). One of the examples presented in this paper is the comparison of simulated waterflood experiments under different Nc (i.e. capillary desaturation) and constant wettability (NW) conditions. These experiments were performed in samples from a deep viscous oil reservoir taken 1 foot away from a slab core sample. The simulation results show that the oil recovered is consistent regardless the depth of both samples tested (Figure 4a). To further validate the methodology, a waterflood simulation was conducted with an oil-water viscosity ratio similar to the fluids used in a physical experiment (Figure 4b). Despite the slight differences in the oil recovered from 0.2 to 0.8 PV of injected water, the pore-scale flow simulation reasonably reproduces the experimental results of the waterflood under adverse mobility conditions. Figure 4b also shows the polymer flood run in the laboratory using core plugs from the same pay zone interval of the reservoir under evaluation. However, polymer flood simulations (viscosity ratio sensitivity analysis) are still under evaluation to compare with actual physical experiments performed as part of a pilot project design. Hence, these results will be discussed in a future publication.

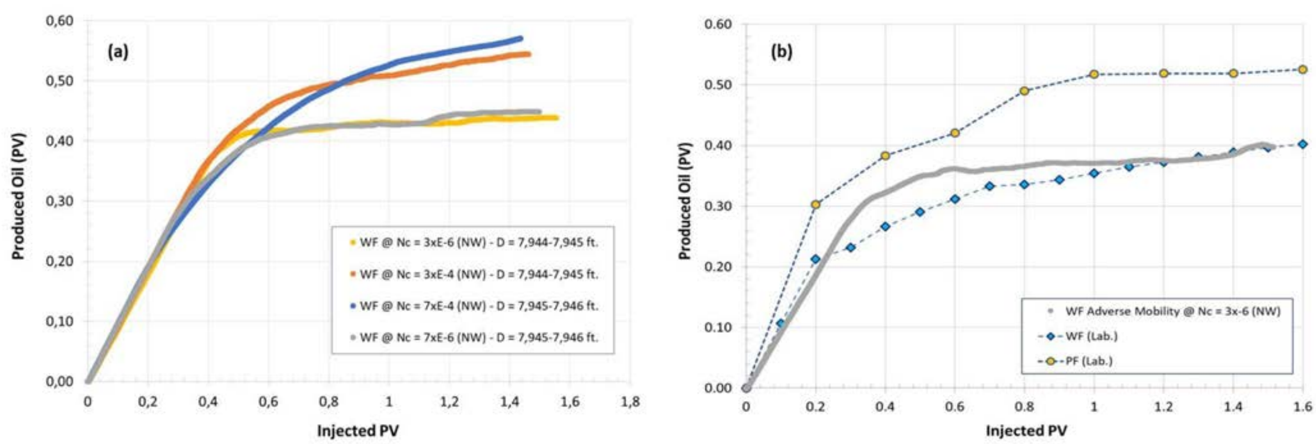

Figure 4—Produced oil vs. injected pore volume (PV) of water different corefloods based on Lattice-Boltzmann simulation: (a) capillary desaturation at NW conditions for rock samples at different depths; and (b) comparison of digital vs. physical waterflood experiments.

Final Remarks

The use of EOR screening tools representes a very useful approach to preliminary evaluate the potential of different oil recovery processes in a given reservoir, especially if the tools can identify case studies implemented in fields ("possible analogs") with similar properties and conditions to the reservoir under evaluation. As presented in this paper, the results of the EOR screening tools are relatively similar regardless the screening approach used. The latter is expected because both screening tools evaluated, and potentially others documented in the literature, are based on the same information. The main goal of this study is to highlight the importance of incorporating geologic information ("geologic screening") that is generally overlooked and can have a tremendous impact on project performance and economics, especially chemical EOR methods.

Based on the ASP floods discussed in this document, clearly suggests that experimental protocols and numerical simulation prediction of this chemical EOR method shows some weaknesses that needs to be addressed. This may explain the limited number of EOR surfactant-based methods documented or pilot expansions during the last decade. Therefore, the oil community interested in evaluating SP or ASP needs to develop new ways of potentially inferring scaling tendencies and possible adverse interactions between the oil and chemicals injected ("stable emulsions"). In any case, the incorporation of professional with an advanced understanding in inorganic and organic geochesmitry is strongly recommended.

Preliminary results confirm the potential of Lattice-Boltzmann pore scale flow simulation to support EOR studies from screening to experimental design and interpretation of coreflood tests, among others. The use of digital rock methods can help reduce evaluation times, optimize the use of reservoir core material and provide valuable information for studies with a limited amount of information and time constraints in a wide range of applications (from exploratory appraisal to the redevelopment of mature fields).

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