Review of Enhanced Oil Recovery Decision Making in Complex Carbonate Reservoirs: Fluid Flow and Geomechanics Mechanisms

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Abstract

As a result of reduction trend in exploration of super-giant carbonate fields and depletion of the proven mature fields categorized as easy oil, development of tight, deep carbonates with more complexities in reservoir rock and fluid behavior have become of interest for exploration and development companies in recent years. New challenges have arisen in development of complex carbonates due to fracture network distribution uncertainty, lateral and vertical fluid behavior heterogeneities, unstable asphaltene content, high H_2S and CO_2 contents and high salinity formation brine. The complexity elements and problems for downhole sampling have made the full understanding of the reservoir behavior and consequently availability of data for further routine analysis and utilization of simulation model as the main way of data integration limited. Therefore, there is an emerging need to better understand the challenges surrounding production and enhanced oil recovery strategies in these reservoirs for an improved oil recovery decision making system. In this paper, the challenges in production, stimulation and enhanced oil recovery strategies in newly-developed complex carbonates are addressed and analyzed based on the changes to the chemical and mechanical environment. An integrated decision-making workflow based on coupled hydro-mechanical mechanisms in water-based EOR methods is discussed.
Keywords: Enhanced Oil Recovery, Carbonate Reservoirs, Smart Water Injection, Geomechanics

1. Introduction

Although more than 50% of the known oil and gas reserves globally are trapped in carbonate formations [1], the primary and secondary recovery methods failed to yield more than 20-30% of original oil in place as they are inherently heterogeneous [2]. As the exploration trend of super-giant carbonate filed has drastically reduced and depletion trend of mature fields, understanding the complexities surrounding productivity and enhanced oil recovery strategies of newly-developed carbonates have become of interest for exploration and development companies in recent years [3]. As shown in Fig. 1, although more than 75 percent of oil in place in Iran are located in Carbonate reservoirs, around 45 percent of cumulated oil produced from carbonate reservoirs and more than 50 percent of total cumulated oil is produced from sandstone reservoirs. As demonstrated in Fig. 1, this is due to lower initial and final recovery factors in carbonate reservoirs compared to sandstones [4].
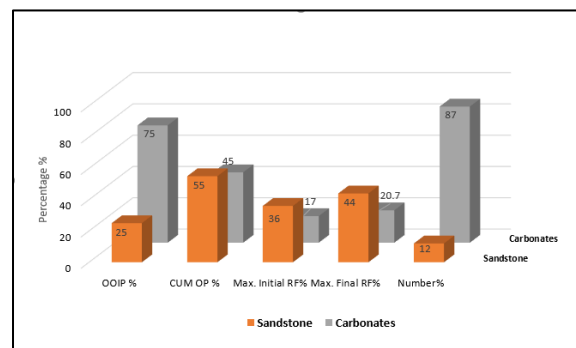

Figure 1. Comparison of carbonate and sandstone reservoirs in Iran basin.

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1.1 Carbonates categorization

Most of carbonates reservoir rocks are to some extent fractured, but the effect of fractures network on fluid flow performance defers. Fractures have a significant impact on oil recovery of the naturally fractured reservoirs with a common scenario of low porosity and permeability matrix blocks surrounded by tortuous, highly permeable fracture network [5].

As described in Fig.2, the ratio between matrix permeability and porosity in carbonate reservoir can dictate the fluid flow in the reservoir. Tier I is the high matrix porosity and low matrix permeability, where matrix provides storage capacity and the fracture network transport hydrocarbons to producing wells. While in Tier II, the effect of the fracture network is less significant on fluid flow due to matrix high porosity as well as permeability. Fractures enhance permeability in this type of reservoirs, rather than dictating fluid flow. The fluid flow and production in Tier III and IV reservoirs are strongly controlled by the fracture intensity and fracture network distribution [6]. The carbonates reservoirs addressed in this paper as complex carbonates, are in Tier I or II, with fluid flow and production mechanisms less influenced by their partial fracture network. Therefore, despite the classic naturally fractured reservoirs, the recovery mechanism in complex carbonates is dominated by viscous displacement rather than capillary imbibition.
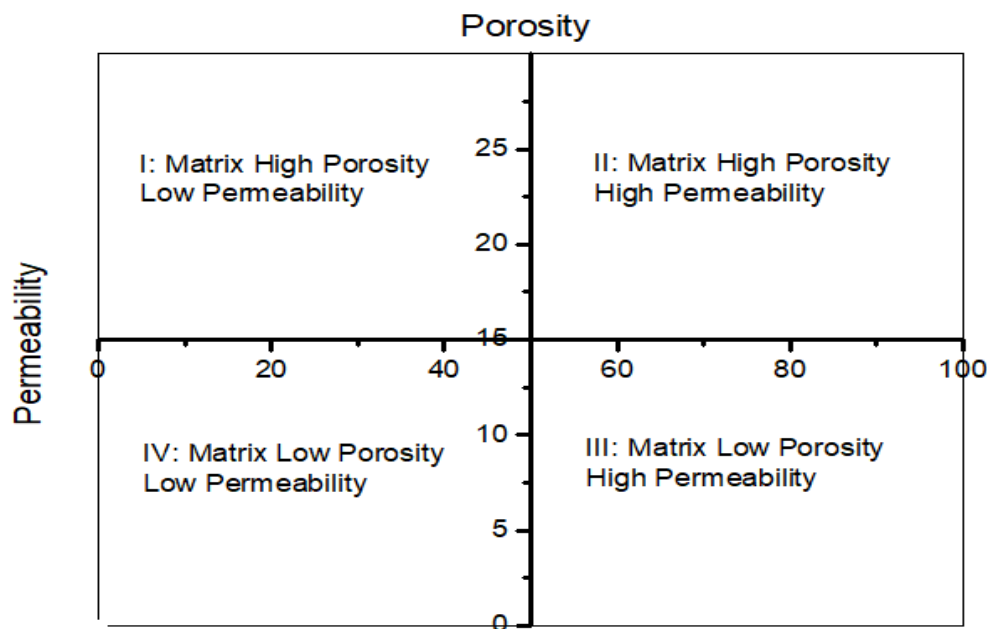

Figure 2. Matrix classification in fractured reservoirs [6].

1.2 Complexity Elements

The parameters described in Fig. 3 are the components that contribute to the complexity of low permeability with high crude viscosity carbonate oil reservoirs. Some major formation damage mechanisms have been associated with the drilling phase in low permeability carbonates due to the high saline formation brine, initial oil to mixed-wet state of the rock and the rock minerology [7]. High salinity of formation brine and the presence of clay minerals such as illite, kaolinite and montmorillonite also impose limitations for injection fluids selection in carbonates. Rock-fluid incompatibility of drill-in fluids can induce damage more likely in low permeability with high crude viscosity carbonates rather than high permeability with low oil viscosity [7]. The complications associated with the presence of shale layers and tight spots in multi-layered

reservoirs have led to stuck-pipe incidents, costly sidetracks and increased non-productive time during drilling stage [7]. The carbonate reservoirs with unstable asphaltene content of the crude oil encounter serious issues in downhole operations such as acidizing or routine sampling that causes high repairment costs and limits the criteria for EOR selection [8]. Various reasons such as pressure drop below on-set pressure, injection fluid/oil interaction or mixing of reservoir fluids can trigger asphaltene precipitation in the wellbore or reservoir. Asphaltene deposition-induced problems can be observed in in initial production, acidizing stimulation or carbon dioxide injection as EOR.

Many deep, tight carbonates in Middle East poses critical conditions of sour fluid (2 to 4% H_2S) at high temperatures (120-170 ^{0}C) and pressures (>7000 psia) that enforce corrosion risks to well completion and surface facilities due to thermo-chemical sulfate reduction and cracking of sulfur organic compounds [9], [10]. The selection, corrosion inhibition and placement of stimulation fluids in wells has been challenging in these conditions, which requires multi-stage matrix treatment, retarded acid formulations and careful selection of acid additives [10]. Reservoir souring due to reduction of bacterial soluble sulfate associated with injected water needs especial considerations in the EOR selection of geologically sour fields.

Apart from the petrophysical evidences, oil and gas density measurements during production logging test (PLT), variations in GOR, H_2S and CO_2 contents and measured APIs vs. depth have indicated signs of vertical changes in PVT or lateral variations in oil properties of stratified, tight carbonate reservoirs [7]. Although a high degree of variations in petroleum fluids of sub-zones of a reservoir is not usual, similar behavior is observed in some Middle East carbonate fields such as Al-Shaheen field in Qatar, which leads to serious levels of complexity to tight carbonate reservoirs [7]. One hypothesis for lateral compartmentation is that the reservoir has been charged by separate oil pulses followed by gas influx and biodegradation. One might expect the reservoir fluids to have attained equilibrium at maturity due to molecular diffusion and mixing over geological times. However, the diffusive mixing may require many tens of million years to eliminate compositional heterogeneities. In deep reservoirs that are not mature enough for uniformity in composition as well as temperature and pressure gradients, composition grading vs. depth can be observed.
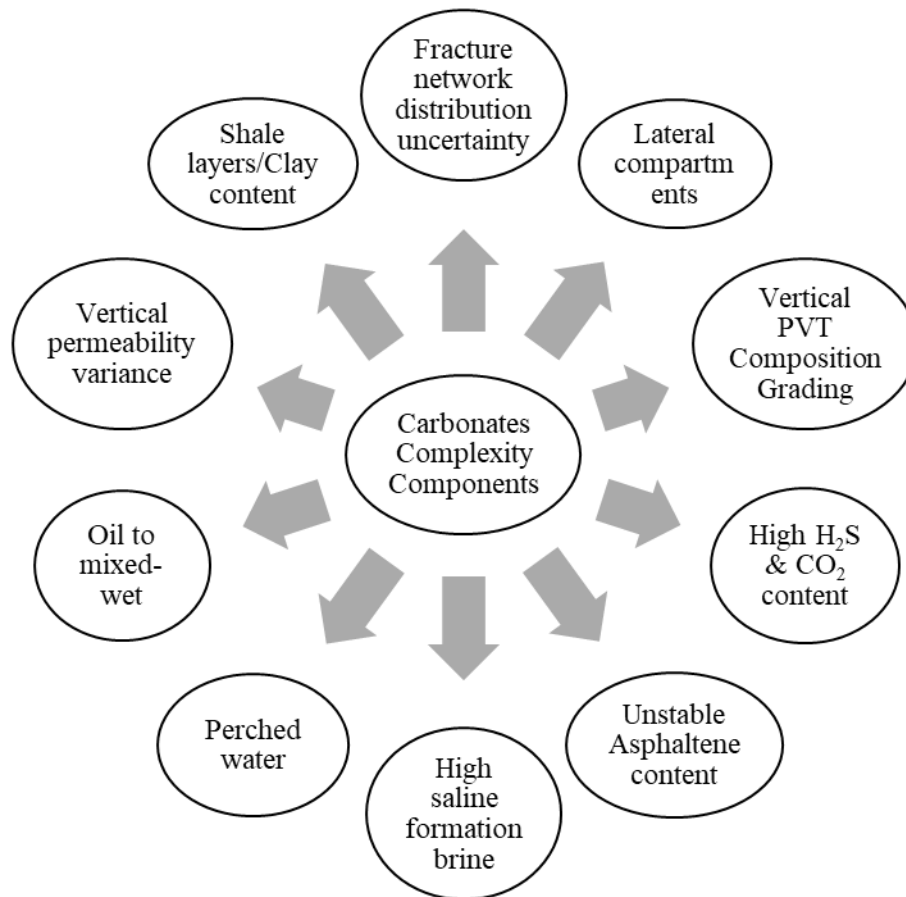
Figure 3. The complexity elements in EOR selection of carbonate fields.

2. EOR Implementation in Complex Carbonates

Taking into account the complexities involved in operation of this type of reservoirs, the integrated reservoir-well-facility management (RWFM) in terms of surveillance, well-based IOR, production system bottlenecking and flow assurance is necessary for the optimized field management, from day 1 of production. In cases where a large variation in fluid properties applies, intensive laboratory investigations and pilot tests are justified to better understand the applicability of EOR processes in different parts of the reservoir. The RWFM classification of activities and the relation of IOR and EOR targets in complex reservoirs are described in Fig. 4 as a function of time. As can be seen in Fig. 4, IOR activities such as stimulation, artificial lift methods and lateral infill drillings can be applied to extend the field EOR economic limit.
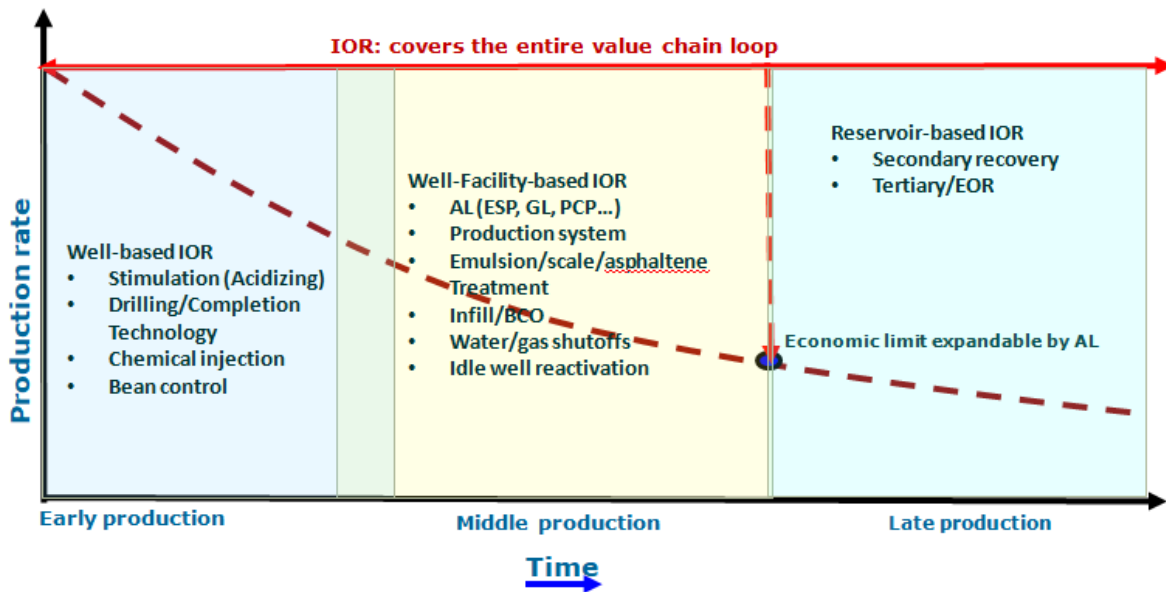
Figure 4. Classification of IOR/EOR activities as a function of time, tailored for complex carbonates.

2.1 Criteria Screening

The amount and probable location of remaining oil as well as the type of target oil (bypassed or residual oil) needs to be studied in EOR decision making process to access the potential list of EOR methods for production of the remaining oil [11]. Conventional screening is complemented to expand the evaluation and therefore further validate applicability (feasibility) of the most practical recovery process in the field under evaluation. It is based on the comparison of the reservoir properties of the field under evaluation with the criteria of known IOR/EOR projects summarized by Taber et al [11]. The reservoir and fluid properties require for conventional screening are oil API degree, oil viscosity, oil saturation, reservoir depth and thickness, reservoir temperature and rock porosity and permeability. The objective of the screening exercise is to rapidly see if a field or reservoir under consideration presents enough commonalities with field experiences in the same area or elsewhere. If the answer is positive, then the likelihood of finding referential information as to what the course of action was in similar reservoirs can be investigated; if, on the other hand, the reservoir under evaluation turns out to be an exceptional case with no comparable field conditions in EOR, care must be exercised to avoid excessive risk in the application of an EOR process. Table 1 illustrates the screening criteria of the classic EOR methods in traffic light concept, in respect to conditions and complexities of tight carbonate reservoirs.

As can be seen in Table 1, immiscible and miscible gas injection methods is indicated as the most feasible EOR approach based on the initial screening criteria analysis and oil properties. Fluid properties variation and unexpected large-scale permeability heterogeneities can negatively affect gas injection in this type of reservoirs, which requires extensive PVT sampling and pilot trial to investigate. Air injection is considered unsuited for light oil reservoirs, as the combustion tests in the absence and presence of core rocks suggested [12]. As illustrated in Table 1, the thermal methods are strongly not recommended for tight carbonates, and the chemical methods such as polymer injection can face issues in terms of permeability and oil viscosity range.

Table 1: Rapid screening of EOR potentials for carbonate reservoirs [13].

EOR method	Depth (ft.)	Permeability (mD)	Viscosity (cp)	Fracture/ Vertical permeability	API	Oil sat. (%)	Temp (^{o}F)	Technical comments
Thermal	<3000	>200	>100	Not favorable	>15	>50	>100	Field size matter Fuel needed
HC	>4000	Not critical	<3	Low macroscopic sweep	>23	>30	Not critical	High operation cost interactions
CO_2	>2500	Not critical	<10	Low macroscopic sweep	>25	>20	>88	Scale ($CaSO_4$-$FeCO_3$) Corrosion Asphaltene deposition High heterogeneity
N_2	>6000	Not critical	<0.4	Low macroscopic sweep	>35	>40	Not critical	Asphaltene deposition Fault/Heterogeneity Permeability contrast
SP, ASP	<9000	>50	<35	Not critical	>20	>35	<200	Chemical cost Large well space control Souring Water hardness >1K ppm Water salinity>50K ppm Clay, gypsium, anhydrates Limited field/pilot tests
Polymer	<9000	>50	>10	Not critical	>15, <40	>70	<200	Polymer injectivity Water hardness>1K ppm Water salinity>100K ppm

The main limitation of rapid screening method is that the novel EOR methods such as smart water or low-tension gas injection methods, which are not widely implemented field-wise, are neglected as well as many practical aspects that can change the EOR feasibility results.

2.2 Geological screening (Analogy)

Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure), and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery [14]. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) Same environment of deposition; (iii) Similar geological structure; and (iv) Same drive mechanism.

Geologic characteristics, such as trap type, depositional environment, geologic age, lithology, type of structure, and digenesis, are used to establish a comparison basis between a field under evaluation and EOR projects recorded in a database or information documented in the literature. Significantly less analogy reports are performed for carbonates in comparison with sandstone formations. However, we have developed a radar plot based on properties of different similar carbonate fields to our focus area, as demonstrated in Fig. 5. Gas-based EOR methods (shown in red color) are applied in Brazeau River Nisku Field and Beaver Creek Field, while water-based EOR approach (shown in blue color) is implemented in Ekofisk, Cotton Creek, Sabriyah and Asab fields [[15],[16]]. It can be concluded from the radar plot (Fig. 5) that low permeability, deep and light oil reservoirs are most proper candidates for gas injection, if applicable. While, surfactant stimulation or low salinity water injection can be applied in a wider range of reservoirs in terms of rock properties (porosity, permeability and depth).
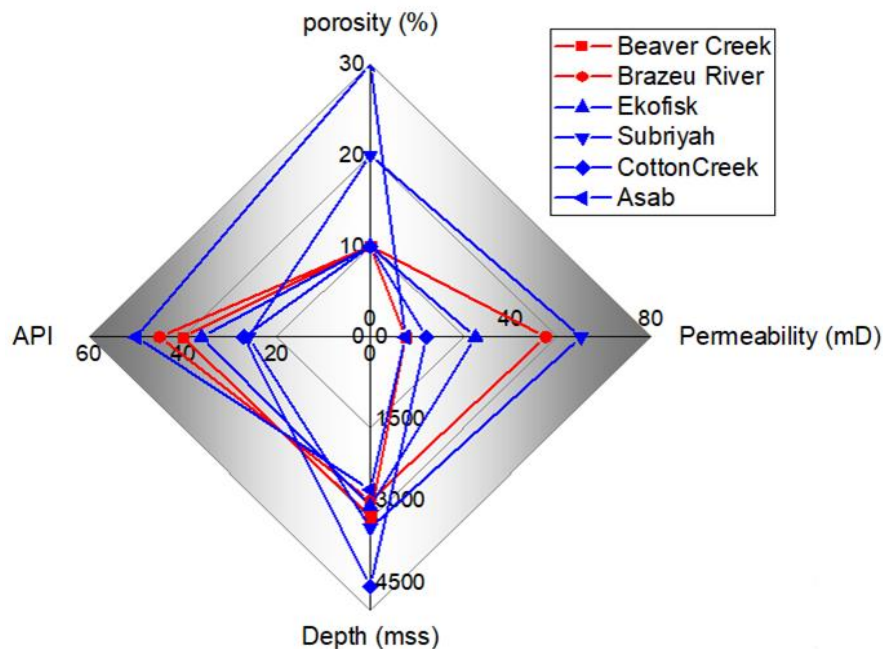

Figure 5. Geologic analogy for gas-based and water-based EOR field applications.

The EOR application workflow and development history in the above-mentioned carbonate oil fields and the observed results over time are presented in Table 2. As stated in Table 2, miscible hydrocarbon (HC) injection and CO_2 injection in Brazeau River Nisku Field in Edmonton Alberta and Beaver Creek were successful in terms of reservoir pressure maintenance. In Ekofisk formation, sea water (SW) program was selected for pressure support and oil displacement, as well as prevention or reduction of the depletion-induced reservoir compaction. The field observation showed a great success by SW injection for oil displacement due to a wettability alteration mechanism involving Ca^{2+}, Mg^{2+} and SO_4^{2-} in seawater [17]. However, compaction and consequently subsidence in water-flooded area continued at a rate of 12 cm/year. Experimental studies on chalk cores showed that removing SO_4^{2-} from SW can decrease compaction, but the oil recovery as a consequence of wettability alteration will also be drastically reduced. Therefore, a

workflow is suggested in this paper for studying interrelation of injected water salinity and subsidence due to rock weakening effects.

Table 2. EOR development in complex carbonate reservoirs [9, 10, 18, 19].

Carbonate Field	Reservoir Formation	EOR Application Workflow			
		Level 1	Level 2	Level 3	Final Status
Asab	Thamama zone B	Powered WF due to low initial reservoir pressure	Immature water B.T. due to small distance between inj. And production wells and high permeability facies	Optimization concept applied: restricted water injection in some zones	After 15% of OIIP produced, water advance has been adequately controlled.
Sabriyah	Mauddud	9 spot SW inj. due to early depletion in filed, since there is no aquifer	Water B.T. due to conning effect from vertical injectors	Horizontal prd. and inj. to avoid B.T. from injector or OWC	Overall improvement of 30% in production rate and maintained water cut rate compared to non-horizontal wells.
Ekofisk	Lower Ekofisk	SW injection for pressure support, oil displacement and decrease reservoir compaction	A great recovery success, however, subsidence continued due to water weakening effect on chalk	Remove sulfate from SW to reduce subsidence, oil recovery reduced	SW acting as smart water will continue as EOR option.
Cottonwood Creek	Dolomite class II	Single-well surfactant soaking initiated (1 week), but not encouraging results obtained	Acid pretreatment (HCL 15%) was eliminated and surfactant concentration increased to 1500 ppm	Wettability alteration to less oil-wet rock resulted in oil recovery increase	Surfactant soaking were made at 23 wells, with general trend of oil recovery, however, not significant.
Beaver Creek	Madison	WF started after pressure drop due to natural depletion	After 40 years of WF, oil rate declined and water cut increased	Miscible CO_2 inj. in centre of reservoir and water injection down dip to maintain pressure above MMP	No experience of serious gas B.T., conformance issue in several inj. wells,
Brazeau River Nisku	Pool D	Gas injection to increase the reservoir pressure	Early production of gas after 6 months of injection	Miscible HC inj. due to early gas B.T.	Miscible method increased RF by up to 15%

From the geological screening study in US oil fields, based on the crude oil prices in the last decade, EOR methods by gas injection processes have been the most used recovery methods for light and medium crude oil reservoirs, especially in carbonate reservoirs with low permeability/injectivity. Chemical flooding has been shown to be sensitive to oil prices, highly influenced by chemical additive costs, in comparison with CO_2 floods. EOR chemical methods in U.S. carbonate reservoirs have made relatively small contribution in terms of total oil recovered. Chemical floods are not expected to grow significantly in the near future, especially in U.S. carbonate reservoirs. However, the evaluation surfactant injection for wettability alteration and reduction of IFT will be critical to recover by-passed and residual oil in carbonate mature waterflooded reservoirs. Current efforts on the evaluation surfactant injection for wettability alteration and reduction of IFT surfactant stimulation projects and Alkali-Surfactant injection to improve well injectivity in carbonate reservoirs in the U.S. and abroad will certainly provide new insights useful for future chemical floods in these type of reservoirs [20].

3. Gas-based EOR Mechanisms in Carbonates

Over 48% of total production from EOR projects in the US carbonate fields are coming from gas injection, mainly CO_2 EOR. Gas injection and in particular CO_2, is by far the preferred EOR method in shallow-shelf carbonate light oil reservoirs compared with thermal and chemical methods [20]. The migration towards CO_2 floods is consistent with the rise of energy cost and natural gas prices, as well as the benefits of carbon capture and storage context. High CO_2 microscopic sweep efficiency, oil swelling and viscosity reduction in tight carbonates with light crude oil are the main beneficial mechanisms in CO_2-EOR. The crucial benefit of CO_2 flooding come from the interactions between CO_2 and oil and its all-proportion solubility with light oil and partial solubility with heavy oils in a wide range of pressure and temperature [21]. The solubility of CO_2 with oil can however be detrimental to the recovery process if asphaltenes are formed. During miscible hydrocarbon or CO_2 flooding, the contact between the solvent and oil may cause changes to the oil equilibrium conditions which may trigger the precipitation of asphaltenes [22]. In carbonate reservoirs with asphaltene prone crude oil, asphaltene can be precipitated due to the changes in pressure, temperature and oil composition. The decline in pressure due to depletion and the incompatibility of commingle production layers with different PVT behavior or acid-oil during acid stimulation, gas lift or gas injection are the main sources of asphaltene precipitation. Asphaltene precipitation and consequently deposition can be detrimental to both surface and subsurface facilities due to pipeline or wellbore plugging [23]. If precipitated in reservoir during CO_2 injection, it may deposit to the surface of pores or plug the pore throat causing permeability reduction and wettability alteration and formation damage [22]. There are empirical correlation-based methods to estimate deposition of asphaltene, which are more concentrated on the relationship between pseudo components (Resins, Aromatic, asphaltene, saturate) as well as reservoir pressure [22]. However, the risk of asphaltene instability and deposition due to interaction of injected gas and reservoir fluid at different pressures can be studied by using visual cell in asphaltene onset pressure tests (AOP).

CO_2-EOR macroscopic efficiency is also limited by CO_2 lower viscosity than oil that causes near well-bore conformance problem and mobility contrast issues, which is accentuated by reservoir heterogeneity [24]. Alternating slugs of water and CO_2 (WAG) was applied to improve front stability and displacement efficiency through formation of three-phase flow. However, CO_2-WAG is negatively influenced by viscous/gravity ratio and formation heterogeneity that can cause reduced three-phase region, and water segregation. The excessive amount of water injection in WAG results in corrosion and injectivity issues [25]. Chemically enhanced gas process also known

as low tension gas (LTG) such as foam assisted WAG (FAWAG) is applied as improved gas injection process to result in further sweep improvement, reduction of gravity segregation and smoothing heterogeneities [26], [27]. The required tests for miscible or immiscible CO_2 flooding in carbonate fields with the complexities such as asphaltene deposition anticipation and oil/gas contact tests are described in Table 3.

Table 3. Parameter design tests for CO_2-EOR application.

Miscibility Evaluation	Asphaltene Instability	Coreflood
- MMP correlations - Slim-tube test - Vanishing interfacial tension test (VIT)	- De-Boer Diagram - Cleveland Instability Index - Stankiewicz method - Asphaltene stability index - IP-143 test - Asphaltene onset pressure - Static and dynamic asphaltene inhibitor test	- Oil swelling - Microscopic sweep - Formation damage - Wellbore plugging

4. Water-based EOR Mechanisms in Carbonates

Water-based EOR methods includes sea water injection, low salinity water injection, smart water injection or chemical flooding such as micellar polymer, polymer or ASP flooding. Chemical flooding however, has shown to be sensitive to oil prices and highly influenced by chemical additive costs in comparison with CO_2 flood. Of the 320 pilot projects or field wide chemical floods, 57 projects have been conducted in carbonate reservoirs, most of them polymer floods. In US carbonate fields, the majority of polymer floods were developed in early stage of waterflooding as conformance control method. However, total oil recovered contributed to polymer in carbonate fields is reported small due to the early loss of polymer injectivity. Although SP and ASP flooding has shown better oil recoveries than polymer and alkaline-polymer in laboratory scale due to alteration of wettability to more water-wet condition, there is a limited pilot or field wide experience of these types of chemical flood in carbonate reservoirs. Surfactant injection has been the method of choice in US carbonates in recent years, considered mostly as a stimulation strategy. The main objectives of surfactant flooding in fractured carbonates are wettability alteration and reduction of IFT promoting the imbibition process**.** The evaluation surfactant injection for wettability alteration and reduction of IFT will be critical to recover by-passed and residual oil in carbonate mature waterflooded reservoirs. The chemistry of injection water and the injection brine concentration has great impact on the mechanisms of oil recovery in carbonate and calcite formation. The recovery mechanisms involved in water-based injection in carbonates are discussed in the following sections.

4.1 Wettability alteration as a result of clay migration and double-layer expansion

Carbonate rock is neutral to preferentially oil-wet, due to adsorbing the carboxylic material in crude oil onto the carbonate surface. Sulfate ion can act as a wettability modifier alone without any other additives, such as surfactants, since sulfate is a very strong potential determining ion towards calcium carbonates. Sulfate is causing bacteria activity and scale precipitation such as calcium sulfate. Concentration of potential determining ions (calcium and sulfate) as well as temperature is crucial in wettability modifications. Salinity and pH of brine can strongly affect the surface charges on the rock surface and fluid interfaces, which in turn can affect the wettability [28]. Adsorption of sulfate to carbonate increased as the concentration of calcium in seawater increased due to co-adsorption of calcium on the carbonate surface. The imbibition rate and oil recovery increases as the temperature increases due to stronger adsorption of sulfate and calcium

onto the rock surface (chalk). Magnesium ions adsorbs less strongly than calcium onto the chalk surface at low temperature. At high temperature, magnesium substitutes calcium [29]. The experimental results on the effect of low salinity water (LS) injection into asphaltenic carbonate oil reservoir showed the surface rock wettability alteration mechanism is stronger than IFT reduction in the presence of LS brine [30].

Lashkarbolooki et al. (2016) investigated the effects of anionic and cationic chemical surfactants (SDBS and C12TAB) on wettability alteration of carbonate rock [31]. The results of their work showed that the bacterial solution, cationic surfactant (i.e., C12TAB) and their combination are more effective in changing the wettability of carbonate rocks from strongly oil-wet state to strongly water-wet condition compared to the anionic surfactant (i.e., SDBS). According to the proposed mechanism [29], surfactant irreversibly desorbs stearic acid from the dolomite surface via ionic interaction, so the wettability of the surface becomes more water-wet and the Sodium Dodecyl Sulfate (SDS) anionic surfactant was adsorbed on the dolomite surface via hydrophobic interaction between the tail of surfactant and the adsorbed acid; therefore, the wettability of the surface was changed to a neutral-wet condition. The cationic surfactant was more effective than amphoteric and anionic surfactants in changing the wettability to water-wet. Hosseini et al (2019) investigate the effect of asphaltene deposition on rock wettability alteration and oil relative permeability and recovery in WAG process. The results show that asphaltene deposition decreased oil relative permeability and altered rock wettability to oil-wet. By employing nonionic surfactant rock wettability rebounded to water-wet, but it does not reach its original point [32].

3.2 Multi component ion exchange (MIE) between clay mineral surfaces and the injected brine

According to Lager (2006), oil polar components are bonded to negatively charged clay surface either through multivalent cations in case of carboxylate functions (cation or ligand bridging) or directly adsorbed onto the mineral surface in case of basic functions (cation exchange); when low salinity water injected; organo-metalic complex directly adsorbed polar components are replaced by cations present in dilute brine; system is evolving towards a more water wet state. In this theory, multivalent cations in injection brine are thought to be more efficient to adsorb oil [33]. Low salinity water might not work in carbonate reservoirs due to a lack of expandable electronic double layer that can enable multi component ion exchange (MIE) mechanism. It needs more investigation that MIE to happen in carbonate needs low salinity water. Multi-component ion exchange plays an important role in increasing oil recovery during waterflooding in carbonate and calcite reservoirs. MIE describes the competition of ions of pore water (injection or formation) for the mineral exchange sites. Testing of effluent for low salinity water inj. Showed a sharp decrease in Mg^{2+} and Ca^{2+} concentrations, lower than that of invading zones. The analysis indicated that those cations were strongly adsorbed on the rock. Low salinity water has an advantage of lower concentration of divalent ions that precipitate the surfactant and prevent them from increasing the oil recovery. Therefore, in low salinity water, the in-situ generated surfactant will be effective in reducing the interfacial tension between reservoir oil and water [34].

3.3 The pH Change Effect

Low salinity water acting like an alkaline solution results in the rise of pH induced by calcite dissolution and cation exchange when dilute brine is injected. It generates in situ surfactants from crude oil, lowering IFT and then improving oil recovery. McGuire et al. (2005) suggest that the dominant low-salinity mechanism, rather than a shift in wettability, was an increase in pH leading to in situ formation of surfactants through reactions with oil acid components, and that the key effect, therefore, was a lowering of oil/water IFT as seen in alkaline flooding [35]. They did an

LSW experiment using core from a North Slope Alaskan field. From initial salinity of 15,000 ppm, the pH increased from 8 to 10 when low-salinity brine with a salinity of 150 ppm was injected and oil recovery increased from 56% to 73%. It was proposed that as LSW is injected into the core, hydroxyl ions are generated through reactions with the clay minerals present in the reservoir.

3.4 Fine migration during low salinity injection or permeability reduction mechanism

The phenomenon of fines migration during LSW injection is explained by DLVO (Deryaguin-Llangau-Verwey-Overbeek) theory of colloids [36]. It is also associated with a permeability reduction resulting from pore throats and pore constrictions plugging by fine mobilization with flowing fluid. Contradictory results with additional oil recovery without permeability reduction and no fine production can also be listed [37]. A coreflood study of injection of diluted sea water into a low permeability (0.5 mD) carbonate core sample from an Iraqi reservoir saturated with sea water showed increased concentration of Ca^{2+} in effluent samples and images of fines migration and blockage inside the rock. However, no major permeability reduction was observed which was attributed to the compensation effect of dissolution-induced pore enlargement [38].

It can be concluded that mechanisms such as rock surface wettability alteration, sand dissolution due to the reduction of calcium ion concentration in the injected water and the reduction of the interfacial tension are the major mechanisms behind this method that leads to increasing the production of oil reservoirs.Table 4 demonstrates the required tests to design a water-based EOR application in carbonate reservoirs. One of the effective parameters is the temperature of the reservoir. The results of the previous research show that, at 248 °F, the effect of sulfate ion, as well as total salinity of injected water, is of great importance. Similar to low salinity water injection, one of the criteria for the success of the method of smart water injection is the presence of polar molecules in the reservoir oil. On the other hand, there is no specific limit on reservoir temperature and reservoir depth, which is significant given the limitations of other water-based methods such as polymer injection and surfactant injection. Of course, as previous studies are clearly shown, the reactions between rock and fluids in low salinity water injection process is more in high temperature conditions.

Table 4. Parameter design tests for water-based EOR application.

Brine/Oil Interaction	Fluid/Rock Compatibility	Coreflood
- Miscroemulsion test - Osmosis test - asphaltene deposition - asphaltene inhibition - IFT test - Souring (SRB count) - Oil swelling	- XRD to identify clay content - clay swelling effect - reservoir plugging (fine movement) - contact angle test - self-scale tendency for $CaCO_3$ -scale precipitation ($SrSO_4$, $BaSO_4$) - static adsorption test - capillary pressure centrifuge test - Rock dissolution geomechanics test	- Residual saturation - Relative permeability changes in different ions - Formation failure pressure - Formation damage - Microscopic sweep test

4. Interrelation effect of compaction and wettability alteration mechanisms on oil recovery

During the production of oil from reservoirs, the pore fluid pressure is reduced leading to an increase in the effective stresses, which in turn drives compaction contributing to an enhanced oil recovery. Compaction can, however, also cause well failure in the overburden and within the reservoir, and the subsequent subsidence poses a threat to the reservoir-well integrity. Some well-known cases include the Willmington field in California and the Ekofisk field in the North Sea.

The extensive depletion of the Willmington field caused a subsidence bowl reaching a maximum depth of 9 m [39]. The sea floor under the Ekofisk platform sank by 1984 in excess of 3.5 m, and the platform had to be extended (jacked up) at a cost of US $1 billion [40]. Sea water (SW) is injected in reservoir to re-pressurize the reservoir and reduce compaction. However, it has been observed that seawater injection drastically reduces the mechanical integrity of reservoir due to weakening of the rock. Specific ions in seawater have also shown to alter the wettability state of the rock and affect both mechanical strength and fluid flow [41]. The casual relation between wettability and mechanical strength of carbonate rocks, influenced by the potential determining ions, reservoir temperature and initial wettability of rocks have been tested in few experimental studies and coupled geomechanics-fluid flow models [42] and highlighted the importance of these parameters on improved oil recovery.

The workflow for coupled fluid-flow, weakening effect and geomechanical analyses and the governing equations involved in sea water injection is briefly described in Fig. 8. As can be seen in Fig. 8, while sea water is able to alleviate compaction and result in improved oil recovery due to oil-brine and brine-rock interactions, it can itself cause subsidence due to salinity weakening effect on reservoir rock due to the presence of some specific ions. Therefore, simulated sea water or smart water, which is composed of low salinity water with original sulfate ion is suggested to take advantage of reduced capillary force induced mechanisms while reservoir-well integrity is not disturbed due to weakening effect (as described in Fig. 8). The governing equations described in workflow are as follows:

$$\text{Eq. 1} \qquad \sigma = k\varepsilon - bp \; ; \varphi = b\varepsilon + \frac{p}{N}$$

where σ is stress, k is bulk modulus, ε is volumetric strain, p is pore pressure. b is Biot coefficient, φ is porosity and N is Biot modulus [43].

$$\text{Eq. 2} \qquad N_{C_{ow}} = \frac{v\,\mu_w}{\sigma_{ow}\cos\theta}$$

Where $N_{C_{ow}}$ is capillary number between displacing (water) and displaced (oil) fluids, v is fluid velocity, μ_w is viscosity of displacing water, σ_{ow} is interfacial tension between water and oil and $\cos\theta$ is representative of wetting state of rock [27].

$$\text{Eq. 3} \qquad \Delta p_{cc} = \frac{p_{cc}(S_w).(i-k)\frac{\partial x}{\partial S_w}}{x+(1-x).k}$$

Where p_{cc} is hydrostatic pore collapse strength, k is the ratio of pore collapse at water saturations 0 and 1 and x denotes how the strength varies for water saturations between 0 and 1 [42].
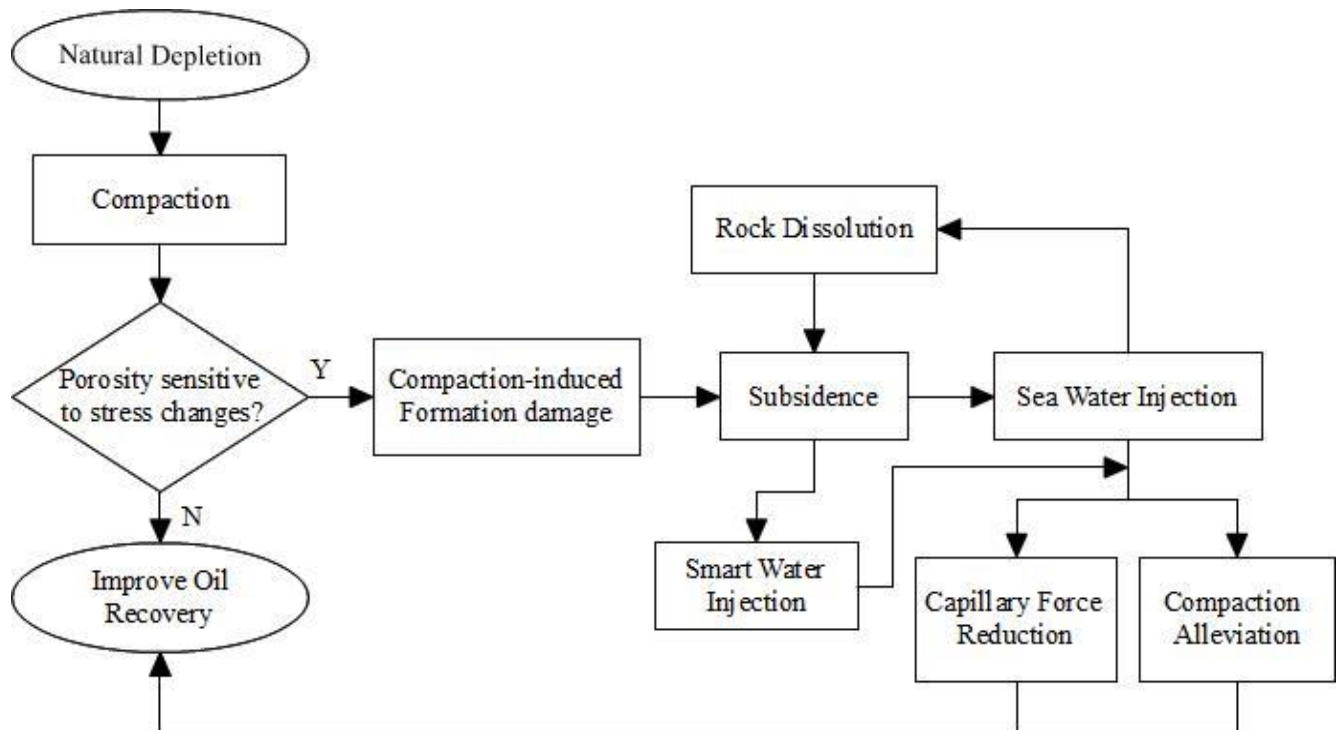
Figure 9. Interrelation workflow for compaction, oil recovery mechanisms and weakening effect during sea water injection and smart water injection.

5. Conclusions

A modified screening criterion for newly developed tight carbonates with rock and fluid complexities such as micro fracture network, tight formation and asphaltenic oil is presented in this study for EOR potentials decision making. The mechanisms involved in the promising gas-based and water-based EOR techniques were discussed based on field or pilot application experiences in analogous carbonate fields. It was concluded that although for tight carbonate, miscible or immiscible CO_2 injection has been widely applied worldwide, the asphaltenic properties of oil limit the application of gas-based methods due to flow assurance issues. Sea water injection acting as smart water in high temperature carbonates of initially oil-wetting state is considered a successful approach taking advantage of both micro (capillary forces) and macro (re-pressurization) aspects of EOR injection. However, the salinity-induced subsidence due to geochemical ions-rock reactions triggers the importance of smart water injection or designed ion water injection in such reservoirs to maintain reservoir-well integrity.

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