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Philosophy of EOR

Tayfun Babadagli, University of Alberta

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Abstract

This paper seeks answers, through a 'philosophical' approach, to the questions of whether enhanced oil recovery projects are purely driven by economic restrictions (i.e. oil prices) or if there are still technical issues to be considered, making companies refrain from enhanced oil recovery (EOR) applications. Another way of approaching these questions is to ask why some EOR projects are successful and long-lasting regardless of substantial fluctuations in oil prices. To find solid answers to these two, by 'philosophical' reasoning, further questions were raised including: (1) has sufficient attention been given to the 'cheapest' EOR methods such as air and microbial injection, (2) why are we afraid of the most expensive miscible processes that yield high recoveries in the long run, or (3) why is the incubation period (research to field) of EOR projects so lengthy? After a detailed analysis using sustainable EOR example cases and identifying the myths and facts about EOR, both answers to these questions and supportive data were sought.

Premises were listed as outcomes to be considered in the decision making and development of EOR projects. Examples of said considerations include: (1) Every EOR process is case-specific and analogies are difficult to make, hence we still need serious efforts for project design and research for specific processes and technologies, (2) discontinuity in fundamental and case-specific research has been one of the essential reasons preventing the continuity of the projects rather than drops in oil prices, and (3) any EOR project can be made economical, if technical success is proven, through proper optimization methods and continuous project monitoring whilst considering the minimal profit that the company can tolerate.

Finally, through the 'philosophical' reasoning approach and using worldwide successful EOR cases, the following three parameters were found to be the most important factors in running successful EOR applications, regardless of oil prices and risky investment costs, to extend the life span of the reservoir and warrant both short and long-term profit: (1) Proper technical design and implementation of the selected EOR method through continuous monitoring and re-engineering the project (how to apply more than what to apply), (2) good reservoir characterization and geological descriptions and their effect on the mechanics of the EOR process, and (3) paying attention to experience and expertise (human factor).

It is believed that the systematic analysis and philosophical approach followed in this paper and the outcome will provide proper guidance to EOR projects for upcoming decades.

Introduction

There is no doubt that EOR is one of the most investigated reservoir engineering areas in the last few decades. Based on the research done and the outcome of field applications, several papers were published on the descriptions (Surguchev et al. 2005; Thomas 2007; Manrique et al. 2010; Armacanqui et al. 2017) and classification of the EOR methods (Taber et al. 1997a-b; Stosur 2003a), applicability conditions of them (Kuuskraa et al. 1983; Bondor 1993; Pautz et al. 1994; Hite and Bondor 2004; Hite et al. 2012; Rotondi et al. 2015) and their screening criteria starting with Taber et al. (1997a-b) producing two pioneering papers followed up by more recent studies (Moreno et al. 2014; Hartono et al. 2017).

Despite the tremendous investment devoted to research into pilot-scale investigations, the ultimate gain from EOR applications has hovered below expectations since the 80s (<10% of total production). Although this can be attributed to the strong dependency of EOR projects on the erratic nature of oil prices, one should also note that the conventional technologies and traditional approaches used for the technical (and eventually economic) appraisal of EOR projects may not be suitable for many cases (complex reservoirs, unconventionals). Beyond that, EOR concepts, modeling ambiguities, lab-to-field-scale upscaling, and even economic models are not well-defined and no consensus has been reached in the technical and economic appraisal of these EOR projects. All these novice concepts encourage revisiting the knowledge gathered and dogmatic assumptions made over the five decades of EOR history, then evaluating the concepts philosophically for the future of EOR projects. All while we are in the transition to completion of the conventional phase of EOR (tertiary recovery after primary and secondary waterflooding phases) and towards the unconventional phase of EOR (tight reservoirs, heavy-oil, heterogeneous carbonates, shale oil, and even enhanced gas recovery for coal bed methane and hydrates).

Looking at the problem from a new perspective, this paper provides a different 'philosophical' approach to scrutinize and analyze the issues raised above. Like many other disciplines, science, technology, and engineering (Bulleit et al. 2014) have philosophical aspects or, at least, a clear connection with philosophical problems (Gonzales 2005). EOR, as a subject part of a petroleum reservoir engineering discipline, has long been researched and applied, yet any comprehensive evaluation of the status using a philosophical approach has not been done. This is particularly needed considering the importance of the subject to improve the energy supply efficiently. It is notable to mention that the research effort devoted to the EOR is tremendous yet the field-scale applications are comparatively limited. These observations all signal that it is the right time to document a comprehensive analysis of EOR methods and applications using philosophical approach (and logical reasoning) to shed light on future endeavors. This paper begins with questioning and re-visiting many unanswered questions about EOR considering both the technical and economic aspects of the current methods and field trials. The main question serves to determine whether it is technical problems, limitations, or the economics of the projects that make companies refrain from EOR applications. Did we solve all technical issues or do we have sufficient knowledge and experience to implement any EOR method in any type of fields? Or, is it purely economics of the method rather than technical constraints? To answer these types of questions, not only was logical reasoning used, but also many EOR cases at field-scale were evaluated.

Description of EOR and updated list of EOR methods

Despite all these efforts, many concepts in EOR processes are not described well and no consensus has been reached. As of yet, even a common description of EOR has not been consistently agreed upon (Stosur et al. 2003b); hence, it is better to start with a definition. Traditionally, EOR refers to tertiary recovery, the injection of any material that does not naturally exist in the reservoir to displace the remaining oil after waterflooding. This, however, may not be the case in some applications including steam injection (usually implemented after primary recovery (Fuaadi et al. 1991; Gael et al. 1994; Hanzlik and Mims 2003; Nath et al. 2007) or even from the beginning of production (Fair et al. 2008; Al-Bahlani and Babadagli 2009).

For the sake of consistency, we provide a specific definition of EOR and describe it as "injecting a fluid, with or without additives, to the reservoir to displace oil while changing the oil and/or interfacial properties and providing extra pressure at the secondary, tertiary, or even primary stage". The main condition is to "inject a fluid" and having, at least, "a pair of injector and producer". With some exceptions of single well applications such as cyclical injections (cyclic steam injection or CSS, cyclic solvent injection or CSI, or pressure pulsing), all methods presented in Fig. 1 cover the cases with a minimum of one injector and one producer.

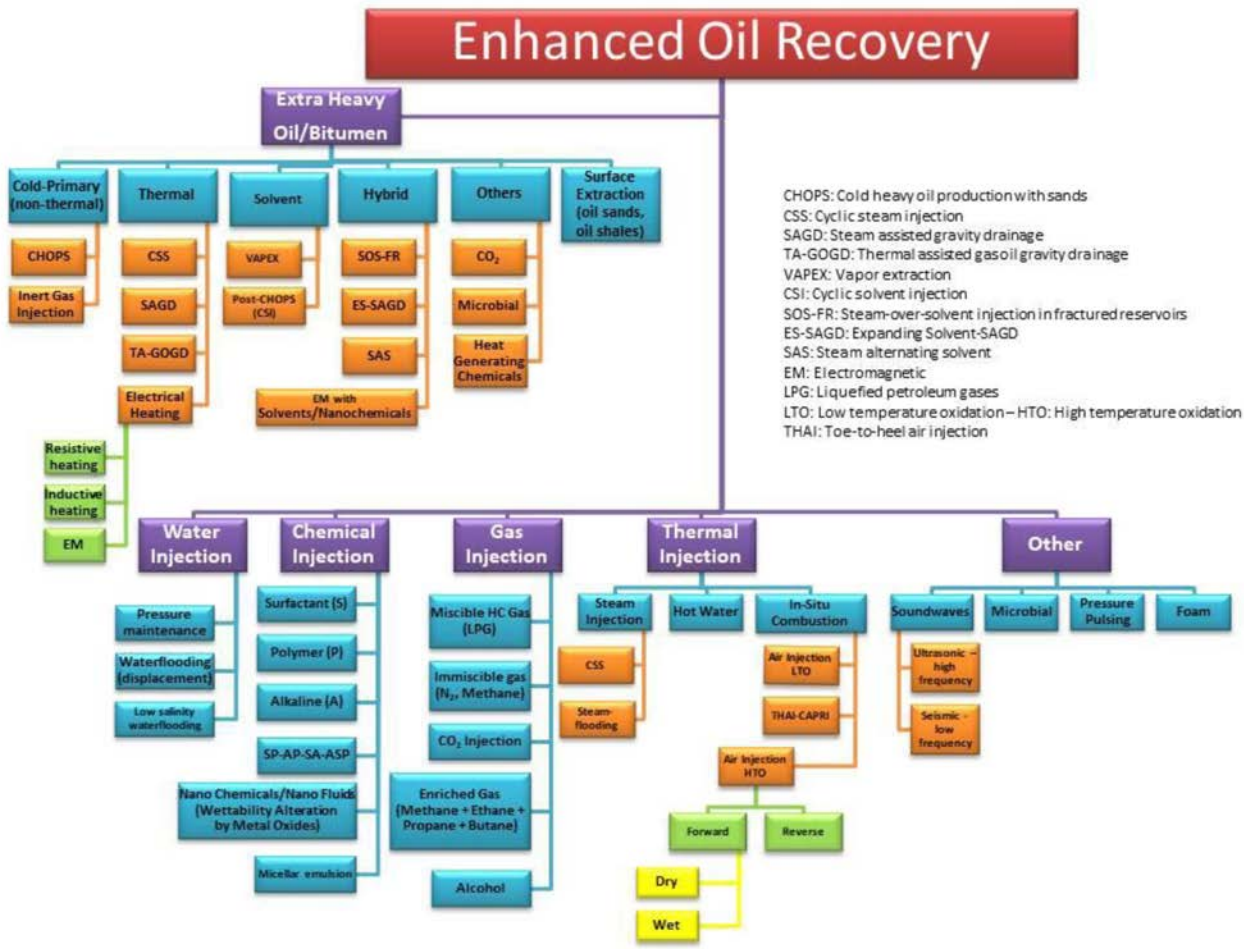

Figure 1—Extended classification of EOR methods.

Note that the classical definition of 'viscous' displacement may not be applicable in all cases included in Fig. 1. Some cases are gravity (steam-assisted gravity drainage, SAGD) or diffusion/convection (CSS, CSI) controlled displacement, or reservoir heating and gravity segregation (thermally assisted gas-oil gravity drainage TA-GOGD).

Traditionally, the term EOR has been used alternatively with tertiary recovery as listed by Taber et al. (1997a-b). Hence, these methods—like most cases included in Fig. 1— are applied in the late stages, usually after waterflooding (Babadagli 2007). This, however, could not be the case in many thermal practices, of which are applied at the secondary (before waterflooding) stage (Fuaadi et al. 1991) or even as a primary method like SAGD (Al-Bahlani and Babadagli 2009). Regardless of the application stage, all heavy-extra heavy-oil recovery methods are included as EOR techniques in the schematic in Fig. 1.

Waterflooding in the same schematic was also considered an EOR method as injection wells are used to displace oil. Overall, the order of the applied EOR method was not considered to be critical and any

method intended to change fluid (oil or water) or rock properties (surface characteristics, wettability) and to displace oil by viscous or gravity forces are included in Fig. 1 as an EOR method. In another definition, any techniques applied to increase the Capillary Number ($N_{ca} = \frac{v\mu_w}{\gamma_{ow}\cos(\theta)} = \frac{viscous}{capillary}$) is called an EOR method and included in the schematic in Fig. 1.

Similar to the extra heavy-oil cases, EOR techniques in unconventionals (tight sand, shales, etc.) might also be applied at the primary stage as the primary recovery is uneconomically slow. Typically, the methods are associated with severe hydraulic fracturing. Also, EOR methods are highly limited, especially for shales. To date, CO_2 injection (Joshi 2014; Alfarge et al. 2017a-b-c-d; Jin et al. 2017, Jia et al. 2019) has been suggested as a primary method and studies are limited to lab-scale analyses and numerical modeling (Yu et al. 2015) with a few pilot trial exceptions (Alfarge et al. 2017a). Alharthy et al. (2015) also tested the injection of CO_2 and other gases (hydrocarbon and nitrogen) as EOR methods experimentally and numerically for the Bakken unit. The use of chemicals for unconventionals are highly limited and rarely considered as EOR methods due to incompatibility of water and chemicals with shales, but could potentially be applied in tight sands (Delamaide et al. 2014; Huang et al. 2019).

As seen in the above summary, EOR methods for unconventionals are at the stage of laboratory research (Gamadi et al. 2013; Sheng 2015; Sharma and Sheng 2017; Yu and Sheng 2017; Yu et al. 2017) with limited field applications (Sheng 2017) and no commercially successful field-scale projects have been reported yet. Therefore, these techniques, i.e. gas or chemical injection associated with hydraulic fracturing, were not included in Fig. 1 and will not be included in the analyses done in this paper.

Potential of EOR: When is the right time to apply it to improve the potential?

The next question asks what the potential of EOR is and if it could be increased by proper strategy and design. As mentioned above, the stage where EOR is applied (in the order of primary, secondary, and tertiary EOR methods) is a critical issue and might affect the potential of EOR and ultimate gain from a reservoir. In most cases, EOR is applied after severe waterflooding or a long period of primary (and secondary) recovery. Traditionally, this is what is described as EOR and the potential is huge as can be inferred from Fig. 2, which shows the discoveries of giant fields over the last century, all at the mature stage, and good potentials for EOR. The statistics given in this figure also reveal that the remaining conventional oil should be the focus rather than expecting new giant discoveries to sustain production.

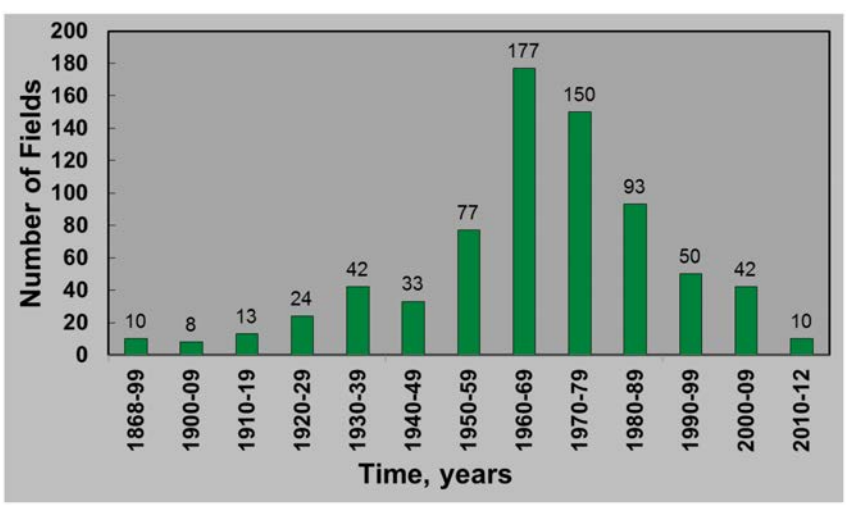

Figure 2—Distribution of the giant field discoveries (Bai and Xu 2014).

There are more than 30,000 fields in the world and only 0.1% of these fields contain more than 50% of the remaining oil (>150 MMM cu.m.), of which is estimated to be in the range of 50-70% of the reserves. This amount is huge and a great potential for EOR, but the optimal time to initiate EOR application is a critical issue when maximizing the potential or ultimate gain. It was argued earlier that elongated periods of waterflooding may result in inefficient application of tertiary miscible floods (Srivastava et al. 1995; Hamedi-Shokrlu and Babadagli 2015; Batruny and Babadagli 2015; Babadagli and Cao 2018a-b). It was suggested that to improve the potential of EOR, one should initiate the application right after the primary recovery (or shortly after secondary recovery, waterflooding) depending on the wettability of the rock (Hamedi-Shokrlu and Babadagli 2015; Babadagli and Cao 2018a).

As opposed to conventional reservoirs that are convenient for the classical tertiary or secondary recovery, in certain circumstances, application of an EOR method in the early stages is a necessity. Although successful applications after primary recovery exist like the Duri field steamflooding case (Fuaadi et al. 1991; Gael et al. 1994; Nath et al. 2007) or historical steam injection applications in California (Hanzlik and Mims 2003), most of the steam injection projects have been applied at the primary stage, especially for extra heavy-oil or bitumen cases (Edmunds et al. 1989; Mukherjee et al. 1994; Yee and Stroich 2004; Fair et al. 2008; Al-Bahlani and Babadagli 2009; Stark 2011). Steam injection in these types of reservoirs may yield extraordinarily high recovery factors indicating huge recovery potential. These projects turned out to be economically viable and continued during the periods of slumped oil prices ultimately yielding high recoveries and profits. Examples include SAGD with an average recovery around 50% OOIP (Jimenez 2008) or CSS processes with a 25% (or more) average recovery (Fair et al. 2008; Stark 2011).

Fig. 3 and Figs. 4a-d show the amount of oil recovered by EOR at different time spans; Fig. 5 illustrates the variation of the number of projects for the same time period and EOR methods as in Fig. 3. In the USA, if not worldwide, while thermal methods were dominating the total EOR recovery by far in the 80s and 90s (Fig. 3), gas injection (especially CO_2) picked up over the last two decades and became the main EOR method (Figs. 4a-b). This increase can be attributed to several reasons, notably the storage opportunity of CO_2 in underground reservoirs while simultaneously using it to improve oil recovery. In fact, most of the CO_2 injected in the field applications was obtained from anthropogenic sources by first capturing then transferring it through a network of pipelines to the desired oil fields (Kuuskraa and Wallace, Page 66, OGC April 2014).

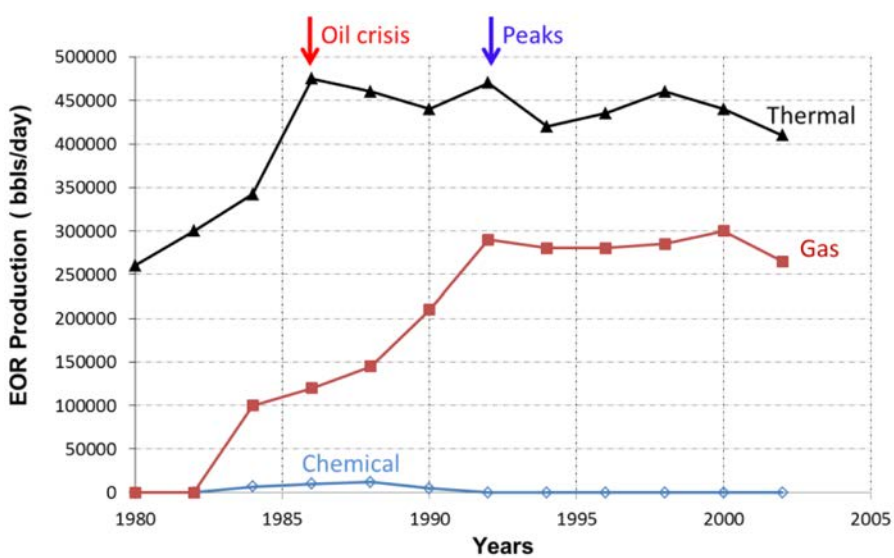

Figure 3—EOR production by thermal, gas, and chemical methods between 1980 and 2002 (regenerated after Stosur 2003).

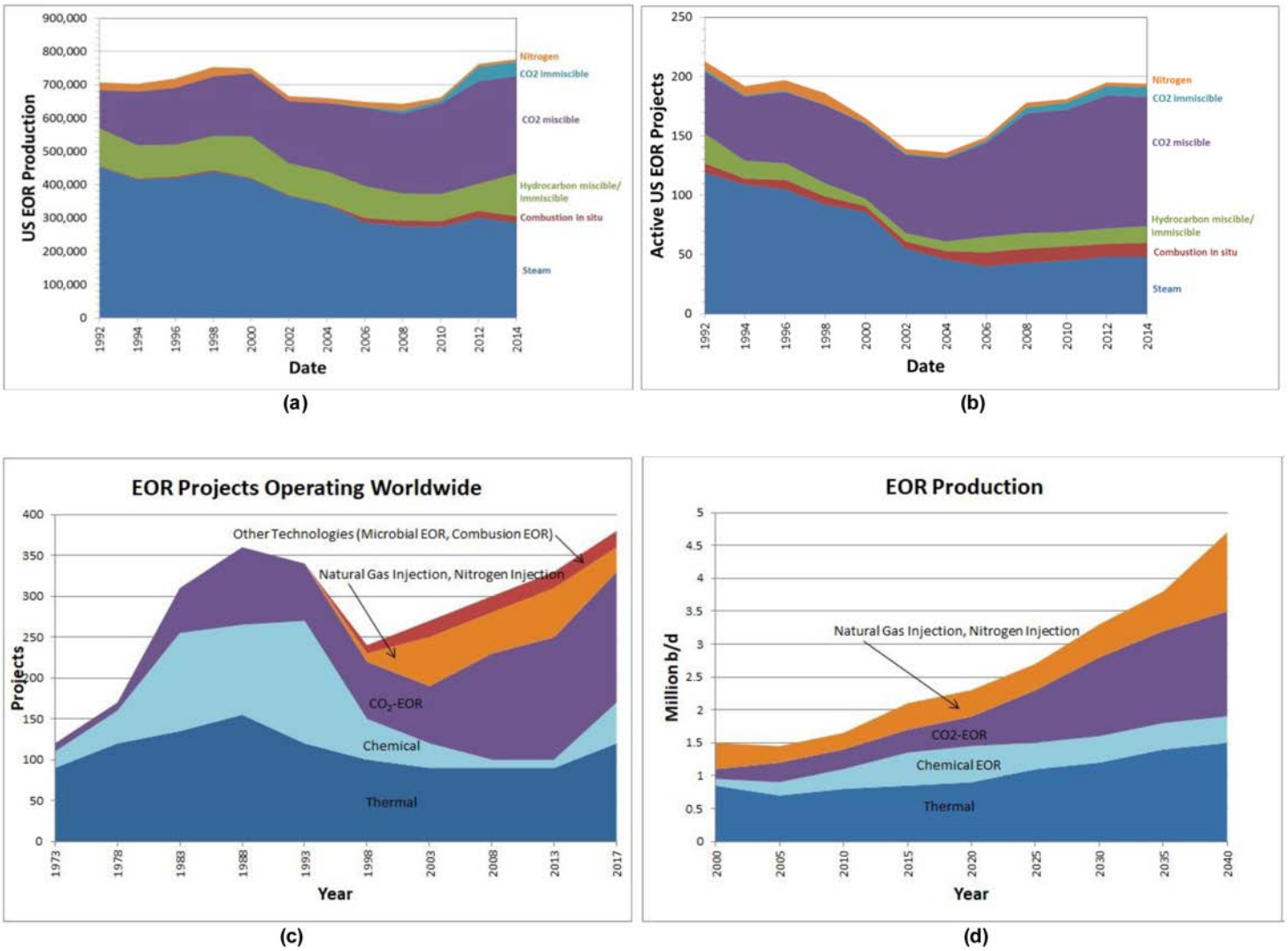

Figure 4—(a) EOR production, (b) active EOR projects in the USA between 1992 and 2014 (graph generated from the data provided by Koottungal (2014) in Oil and Gas Journal, pp 79), (c) the number of current EOR operations worldwide (data obtained from McGlade et al. 2018), and (d) total EOR production worldwide and future prospect (data obtained from McGlade et al. 2018).

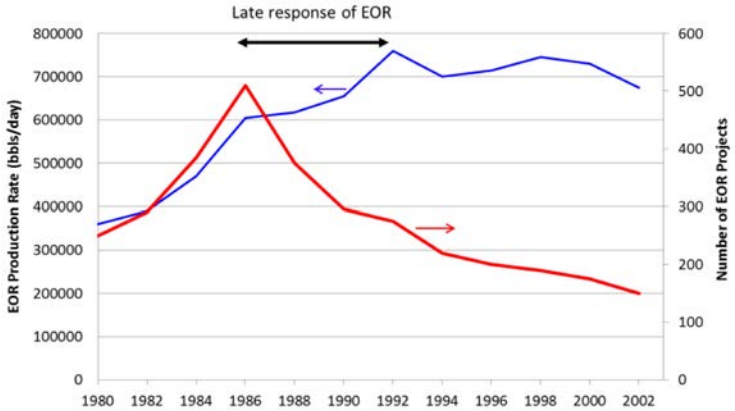

Figure 5—Cross-comparison of active EOR projects and total EOR production in the USA between 1980 and 2002 (graph re-generated after Stasur 2003).

The most recently updated worldwide EOR production was reported by the International Energy Agency (IEA) (McGlade et al. 2018). The number of projects and total EOR production (also including the

production forecast until 2040) numbers are given in Figs. 4c and d, respectively. As of today, the total number of EOR projects worldwide is 375 and the total production is around 2 million bbl/d. The forecasted amount in 2040 is nearly 4.5 million bbl/day. According to the same IEA, the current share of North American EOR is 40%, decreasing from 75% in 2013.

Note that most of the gas injection applications are CO_2 injection and have been applied at the tertiary recovery stage, i.e. after waterflooding (Babadagli 2007; Manrique et al. 2007); hydrocarbon gas injection projects are also applied at that stage (Fig. 4). Hamedi-Shokrlu and Babadagli (2015) reported that hydrocarbon injection may not be effective when applied after severe waterflooding in water-wet (mainly sandstones) systems. The opposite is true for the more oil-wet systems like carbonates. For water-wet systems, hydrocarbon gas injection may not be suitable after severe waterflooding as shown by Hamedi-Shokrlu and Babadagli (2015). Fig. 6 presents ultimate recoveries from the selected successful gas injection applications (Babadagli 2009). This might be the reason for low tertiary recovery potential (it averaged around 10%) by gas injection (Fig. 6). In fact, most of the successful gas (mainly CO_2) applications have been performed in carbonates (Babadagli 2007; Manrique et al. 2007). Furthermore, Christensen et al. (2001) reported that WAG technique yielded the highest improved recovery in carbonate reservoirs compared to sandstone reservoirs. Hamedi-Shokrlu and Babadagli (2015) attributed this to the more oil-wet (or less water-wet) nature of carbonates and concluded that a water-wet or oil-wet nature and non-intergranular pore structure may allow miscible gas (or solvent) to meet with residual oil remaining after waterflooding, compared to water-wet sandstones.

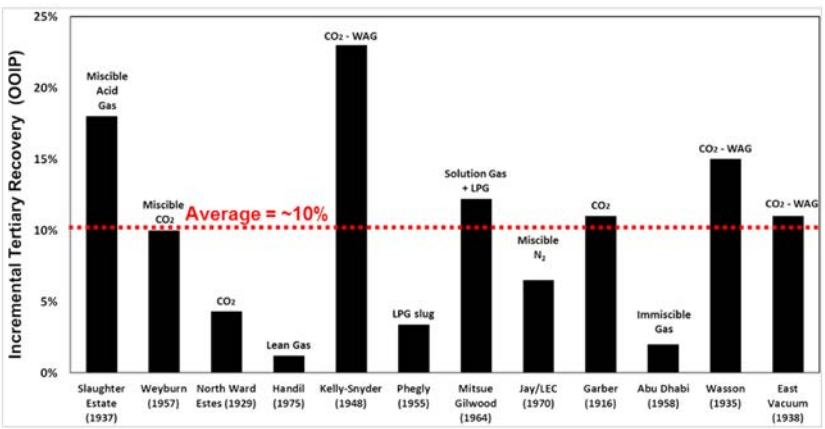

Figure 6—Incremental tertiary recoveries by gas injection in selected successful projects (generated using data from Babadagli 2009).

Based on the above-summarized observations, one may suggest gas injection as a secondary method in water-wet systems rather than tertiary to improve the EOR potential. This is true especially for hydrocarbon injection as the injected gas is not soluble in water; CO_2 injection might be more applicable in reservoirs with different waterflooding history as CO_2 is soluble both in oil and water, yielding a better recovery performance regardless of the reservoir type and wettability. Both Batruny and Babadagli (2015) and Babadagli and Cao (2018a-b) proposed a proper injection scheme (mainly the injection orders) and WAG design to make miscible gas injection in a different reservoir type improve the EOR potential. Another interesting observation is that, despite downturns due to bottomed oil prices, EOR by CO_2 injection escalated while chemical flood significantly declined (compare EOR recovery reported in Figs. 3 and 4).

Note, on the other hand, that chemical flooding might be suitable if applied in water-wet sandstones as is the traditional procedure. Fig. 7 shows the tertiary recovery potential of selected chemical applications around the world. The average recovery is more than 20% (Fig. 7). The sensitivity of chemical injection to oil prices (see the decline of the number of projects after 1986 crisis in Fig. 3) compared to gas injection

should be questioned. In fact, this will be one of the main discussion points in the remaining parts of this paper.

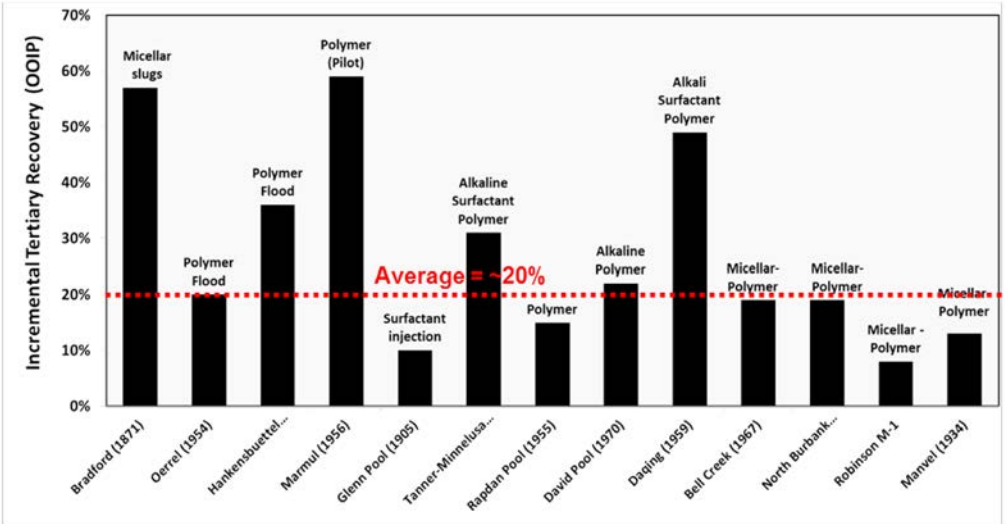

Figure 7—Incremental tertiary recoveries by chemical injection in selected successful projects (generated using data from Babadagli 2009).

A final comment can be made as to the potential of EOR methods based on the incubation period of the applications. EOR is a risky and long-term investment and the expected outcome with meaningful recovery may take a while and long breakeven times can be faced (Cao and Babadagli 2017, 2018). Fig. 5 explains this observation implicitly. Although many projects had been stopped after the drastic decline in oil prices in 1986, EOR methods continued to rise and then stabilized for a period of 10 years. This implies a beneficial outcome seen in the number of years after commencing an EOR project. According to a recent report (Shell 2016), full commercialization of an EOR project may take 3 to 10 years after completing the lab-scale experiments, simulations, single and multiple well pilots, and demonstrations phases, of which is expected to be between 3.5 and 6.5 years (Fig. 8).

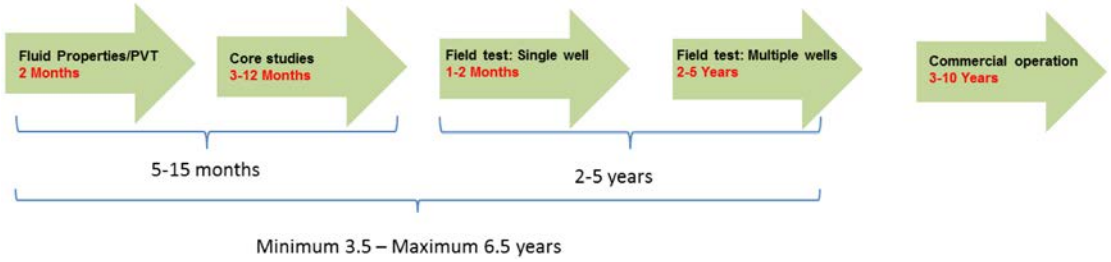

Figure 8—Incubation period of a chemical injection project (re-generated from the figure on page 8 of Shell 2016).

Myths and facts about EOR

Through efforts to standardize the EOR process, certain clichés have been developed in the industry. As these "beliefs" are becoming well-accepted and not questioned, they may be called "myths" and these myths turn into a "belief" restricting the EOR attempts over time. It is, however, a fact that these beliefs should be questioned to open new viewpoints and perceptions. The most common myths selected through observations and discussion with practitioner and perceptions on EOR are listed below. The counter-arguments, described as "facts" are also given:

- MYTH: Technological developments achieved over more than half a century are sufficient to initiate and perform any EOR applications as long as oil prices are high. This means that the economy drives EOR applications rather than technology.

  FACT: Each field is a unique case, and therefore, each EOR application requires different technology, i.e. the way the technique is applied differs field by field. Although the revenue is controlled by oil prices, cost reduction or recovery increase is possible to maximize the profit and make the project economically viable, which is a matter of technology. In other words, perceived loss from the investment in EOR applications can be compensated by optimal production and design strategies as well as improved technologies.
- MYTH: Conventional ("book definition") EOR models and "rules" apply to all cases.

  FACT: Each EOR case is unique (reservoir dependent). A proper and clever/creative design made initially, continuous monitoring, and re-engineering of the process is essential for the success of EOR rather than following standard rules. Experience and expertise play a critical role in this application (human factor).
- MYTH: Pilot tests are needed to assess the performance of EOR methods and economic viability.

  FACT: Pilots are highly time-consuming practices and one has to be careful when applying them to minimize the incubation period of EOR processes, as discussed in the previous section.

  The main purpose of a pilot test was—traditionally—to provide data to assess the technical and economic success (or viability) of an EOR method. Today, simulators are capable of doing this for the "homogeneous" systems as the main mechanisms involved in the EOR process can be captured easily for these types of geologies. For the heterogeneous systems, however, the main mechanisms cannot be captured (object-based models) (Bolshow et al. 2008; Stalgorova and Babadagli 2012, 2014, 2015) and the heterogeneity cannot be easily defined (grid-based models) in the heterogeneous systems (Al-Shizawi et al. 1997; Shahin et al. 2006; Penney et al. 2007; Bogatkov and Babadagli 2009a-b, 2010). Therefore, pilots are inevitable when assessing the EOR potential and potential operational problems, as well as working to fine-tune the models by history matching to the pilot data to simulate the process. These types of pilot studies, however, are highly limited in obtaining an economic assessment as they cannot really be up-scaled to field conditions due to uncertainties associated with geological complexities also affecting the physics of the processes.
- MYTH: EOR is a displacement process (Buckley and Leverett 1942).

  FACT: Simulators used to assess the EOR performances before investment decisions are made are based on continuum models, which is derived from the mass balance (Buckley and Leverett 1942). This could be the fact if the system is convenient for viscous displacement, which is applicable to homogeneous media but may not be suitable for complex systems. The dilemma is that the reservoir complexity cannot be easily described in the grid-based models whereas other alternative models (random walk, particle tracking) are unable to model the real physics of mechanisms despite being more successful in representing realistic conditions of geological heterogeneity (Bolshow et al. 2008; Stalgorova and Babadagli 2012, 2014, 2015).

  Complex EOR applications in complex geologies are highly difficult to model numerically and analytically. Difficulties arise with capturing the real (and multiple mechanisms involved) physics of the process for the former and introducing the heterogeneity for the latter; a good example of modeling TA-GOGD process in the Qarn Alam field representing significant heterogeneities (Macaulay et al. 1995; Al-Shizawi et al. 1997; Shahin et al. 2006; Babadagli and Al-Bemani 2007; Penney et al. 2007). Many simplifications were needed in the geological model and when defining the physics of the process (Shahin et al. 2006; Penney et al. 2007) to simulate the matrix-fracture interaction under thermal conditions; yet, a realistic representation of a fracture network was not properly introduced into the model (Al-Shizawi et al. 1997; Shahin et al. 2006; Penney et al. 2007).

Other good examples for these types of complex fields and processes (steam injection in fractured reservoirs) are the Yates and Bati Raman fields. Pilot applications (smart pilots) were to capture the physics of the process and match the "simplified" models to the field data (Snell and Close 1999; Shahin et al. 2006; Penney et al. 2007; Babadagli et al. 2008; Sahin et al. 2014).

- MYTH: The field development plan with EOR should go in the order of primary, secondary, and tertiary (applied after severe waterflooding as an EOR method).

  FACT: To improve the potential of the field and extend the production life economically, one may start the EOR application at the early stages (Hamedi-Shokrlu and Babadagli 2015; Cao and Babadagli 2017, 2018) skipping (or minimizing) the secondary (waterflooding) stage such as the Weyburn CO_2 (Beliveau 1987; Beliveau et al. 1993) and North Sea/Prudhoe Bay miscible injection projects (Zheng et al. 2013). The correct time to start a project is highly critical especially in miscible displacement processes as mentioned earlier. The same is applied for chemical (starting with low IFT before or after waterflooding) injection, determined by the geology (and heterogeneity) of the reservoir (Babadagli et al. 2005). Furthermore, the water-to-oil ratio available in the reservoirs after waterflooding may have a significant impact on the type of emulsions formed with oil-in-water type of emulsions leading to favorable displacement results (Lee and Babadagli 2017, 2018a-b). Hence, a critical time to start chemical injection in light or heavy-oil reservoirs optimizing the recovery through emulsification exists (Lee and Babadagli 2019).
- MYTH: EOR is purely controlled by oil prices.

  FACT: If this is true, how come many EOR applications continued successfully regardless of the oil prices (see the successful and sustainable EOR projects (over decades sometimes) in Table 1 in Appendix 1)? The main discussion point in the upcoming sections serves to answer the question: what other technical factors (other than oil prices) dominate the decision to initiate and complete EOR operations successfully?

Why are we afraid of EOR?

Given the fact that new discoveries of big-giant fields has slowed (Fig. 2) and the remaining oil after primary and secondary recovery methods is significant in the existing and exploited fields, one may easily claim that EOR deserves more attention as a method to extend the life of the reservoir, as well as increasing the recovery/profit in both the short and long run. Also considering the fact that the contribution of EOR to total oil recovery in the world is less than 10%, one may raise the following question: Why are we afraid of EOR? Possible reasons can be listed as follows:

Limitations in modeling the physics of the process- Lab- (core) to field- (numerical grid) scale for technical and economical assessment:

Traditionally, EOR modeling starts with experimental modeling at lab- (macro/core) scale then is up-scaled to reservoir grid-sized- (mega/giga) scale using numerical simulators. In many cases, lab models (core flooding) are not sufficient to capture the "real" physics and make an initial assessment of the methodology even if the reservoir is very homogeneous and the tests were run at reservoir conditions (SCAL). Multiple mechanisms may play a role in an EOR process and this may not be captured accurately in linear coreflooding experiments and numerical models using relative permeabilities generated from the lab data.

Capturing the physics from core-scale experiments and transferring them to field-scale numerical simulators is still a dilemma. Numerical simulators are based on continuum models, which derive from the "displacement" theory (Buckley and Leverett 1942), and complex mechanisms may not be captured directly through these models. In addition to these simulators, grid-based modeling systems do not allow

an exact description of complex geologies. The description needed can be explained using the images and experimental data given in Fig. 9, also showing an "ideal" displacement process. The viscosity ratio of oil and water is nearly one to one, as the rock is fairly homogenous (Berea sandstone) and water-wet. It yields a "piston-like" displacement with a "perfect" front as can be inferred not only from the image but also through the saturation profile corresponding to this case obtained from the X-ray CT scan images. This is, in a sense, proof of the Buckley-Leverett (B-L) theory and Welge's approach through physical and visual experimentation. The continuum models of which the solution is used in the numerical simulators are based on the same principle (mass balance) as the B-L equation. That means the case seen in Fig. 9 can be perfectly modeled using the numerical simulators as they were designed to model such a displacement process in such a homogenous medium with ideal conditions, meaning that the viscosity ratio is near unity, making the B-L theory applicable, the system is water-wet, and there is no heterogeneity in the system. Such a system can be described and the physics of the process can be captured through relative permeability curves obtained from experiments. With this "accurate" data the performance of waterflooding can be described precisely.

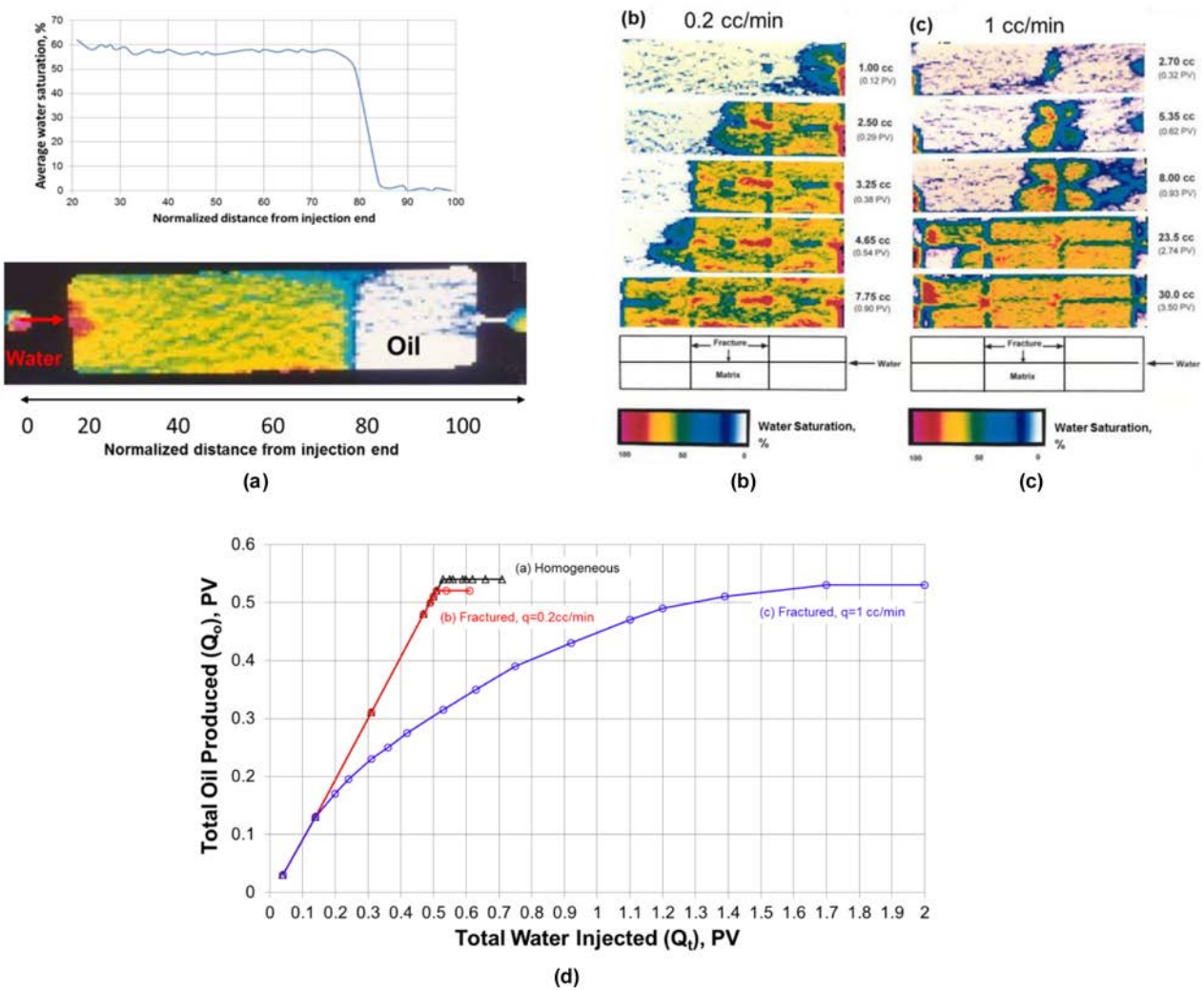

Figure 9—X-ray CT scan image of water injection into oil (kerosene) saturated Berea sandstone (core length is 7.5 cm and diameter is 2.5 cm) for the (a) homogeneous case with corresponding saturation profile (at 0.4 PV injection) (Babadagli 1992; 2011), (b) fractured model with low injection rate (0.2 cc/min), (c) high injection rate (1 cc/min) (Babadagli 1992; 2000; 2011), and (d) corresponding recovery curves for these three cases. Red: 100% water, White: 100% oil. kf : fracture permeability.

In reality, on the other hand, small changes in the system will result in significant changes in the physics of the process. As seen in Figs. 9b-c, one horizontal and two vertical fractures were added to the system

while keeping all the other characteristics the same. When a low rate is applied (Fig. 9b), the displacement, of which is no longer a viscous displacement (except flow in fractures) but purely dominated by capillary imbibition between matrix and fracture, is similar to the homogeneous case following a frontal displacement as seen in the recovery curve given in Fig. 9d.

When the rate is increased fivefold (Fig. 9c), viscous displacement in the fracture plays a more significant role (causing early breakthrough) but imbibition still controls the process. But, the displacement patterns and saturation distributions are totally different and controlled by fracture characteristics such as density, orientation, and geometry, all of which cannot be captured by simulators based on continuum models. In fact, the numerical matched to the experimental data (using the dual porosity option of black oil simulators) was achieved using "pseudo capillary pressure" data obtained by history matching to experimental data allowing matches only for the recovery curves, but not saturation profiles and distributions (Babadagli 1992, 1994). Upscaling these curves to reservoir conditions is still questionable despite the practical options that use dimensionless numbers to describe such a complex process in complex geological media that have been tested in literature (Babadagli 2002).

Even this simple demonstration indicates the limitations in modeling the real physics in the reservoir using continuum models, and any replacement to this type of modeling is yet to be found. The main issue is incorporating the physics and complex geology (fracture network) in the simulators (Bogatkov and Babadagli 2009, 2010). Often times, once the physics are captured (like the continuum models), accurate representation of heterogeneity (like complex structure of fracture networks) is missed as indicated by Stalgorova and Babadagli (2012, 2014, 2015). This leads to using more simplified models like the lump sum models by Farouq Ali (2013) or indirect modeling such as upscaling lab experiments approaches to assess the performance of EOR processes. Another alternative is field pilots, or wider demonstration tests, which are costlier and more time consuming.

Risks involved in field pilots:

Because of the same reason explained above, correct modeling of the complex EOR processes may be difficult to use in decision making. Traditionally, pilots have been run to "model" or down-scale the field-wide application of an EOR method to eventually assess the technical and economic viability of the project. Unless the reservoir involves significant ambiguities in geology and complex physics (e.g. occurrence of multiple mechanisms such as gravity, convection, capillary imbibition, viscous displacement, etc.), numerical simulators in today's technology would be sufficient for technical and economic assessment to a great extent. In complex cases, however, a pilot is needed as numerical simulations fail or can be too risky to assess the EOR performance due to the reasons explained above. These factors, however, may not be sufficient to convince management as these pilots serve to understand the mechanisms rather than down-scale the whole process and directly obtain an economical assessment.

Pilots, however, are difficult to design when complexities, as described above, are involved (Adibhatla and Wattenberger 2009). The main questions to be raised are where to apply the pilot, how long it should be run, how to design it, and what data should be collected. Several good examples can be given for proper pilot design for this, i.e. understanding the physics through a field-scale "experiment". Note that these "experiments" were run by either IOCs or NOCs who can afford such pilots.

The Weyburn and Midale CO_2 injection pilot is a good example of a complex process in complex reservoirs (highly fractured and heterogeneous carbonate). The main idea is to observe the CO_2 transport and distribution in the existence of a fracture network, the pilot involved in tracer, CO_2 injection/production through four injectors and three producers, as well as two observation wells (Beliveau 1987). In this particular case, proper pilot design really helped to implement CO_2 injection (mainly locating injectors and producers) as the field was heterogeneous. In other words, the pilot was not run for economic assessment but instead used to observe the flow pattern of the injected fluids and the effects of fracture alignments on said flow pattern. The pilot was successful in capturing the behavior of CO_2 (and waterflooding prior to it as

reported by Beliveau et al. 1993), eventually leading to one of the biggest and most complex CO_2 injection applications in the world (Barnhart and Coulthard 2000).

Another complex pilot case that helped make a decision on field-wide application is solvent aided steam injection in the form of SAGD (Dittaro et al. 2013) and CSS (Fair et al. 2008; Stark 2011). The later process was tested on two identical pads each consisting of more than 20 wells with (only CSS) and without (LASER), then extended to field-scale commercial application (Stark 2013). The key point in running the pilot was to test the lab-scale experiments and the numerical model study rather than downscaling the process for economic analysis. They observed more recovery of oil and retrieval of solvent than numerical estimation, thus encouraging the extension of the project to field-scale.

A more complex case was reported using steam pilots in fracture carbonates to test the viability of reservoir heating by TA-GOGD on recovery. All attempts done in this regard were to monitor the reservoir performance and analyze the process (Al-Shizawi et al. 1997) and reservoir characteristics (Macaulay et al. 1995). The process was initially challenging due to complexity in reservoir characteristics (fracture density, matrix size, fracture orientations, etc.) and limitations in the simulators to capture the complex physics of the TA-GOGD process. Eventually, the pilot results were meant to match the simulator for technical assessment (Shahin et al. 2006; Penney et al. 2007), but despite all these efforts, the pilot provided only technical data rather than economic as in the previous pilots done for the same purpose in the Yates (Snell and Close 1999; Snell et al. 2000) and Lacq Superior fields (Sahuquet and Ferrier 1982).

In a more recent attempt, a steam injection pilot was run in a fractured carbonate reservoir with marginally deep characteristics effective for steam injection (Sahin et al. 2014); simulation of the heating process followed by TA-GOGD in such a medium was extremely challenging due to the complexity of the reservoir (Babadagli et al. 2009). Although a simple economic assessment was reported based on the energy balance (injected energy and produced energy) from two injectors and several producers, this may not but sufficient for “go” or “no go” type decision making. On the contrary, the data collected was useful not only for the experience gained on well operations, being the first time applying steam injection, but also for collecting data through production and monitoring of wells to analyze this unconventional steam injection application based on reservoir heating and draining oil rather than pattern type injection.

As seen in all these selected cases, pilots for EOR in complex and unconventional reservoirs are yet to provide direct data as to the performance when up-scaled to a whole reservoir, but they can be used primarily to understand the physics of the process to further modify the reservoir models. This is an exhaustive and expensive process that pushes companies towards avoidance of EOR pilots in the decision-making process.

Securing the supply of the materials injected:

Sustainability of the injectant is a critical issue in any EOR project, not only from an economical perspective but also the continuation from a project point of view. Injectants supplied through natural sources are not “limitless” and difficult to predict over a lasting period. According to a recent survey, natural CO_2 sources in the USA are in a decline period (Koottungal 2014). Sahin et al. (2008) reported that, after 25 years of continued supply, the natural CO_2 obtained from a nearby field is alarmingly low with reduced pressure affecting the sufficient supply of gas to the Bati Raman field. Switching from one method to another or using an alternative injectant is not a simple practice and therefore, one risky part of EOR projects is securing a sufficient amount of injectant (water, CO_2, immiscible or miscible gases, etc.), unless it is abundant like air or commercially accessible materials (chemicals). Note, however, that air and chemical injection cover a very limited portion of the EOR practices of today and injectant sustainability remains a critical issue.

Designing proper EOR:

Making a robust decision for any EOR process using simulation studies and pilots is difficult, especially if the reservoir geology is highly complex, or the physics of the EOR process is complicated—in regards to

geological complexity or type of application. In most cases, however, at least the initial design parameters are obtained from simulation studies and small-scale pilots.

Based on initial assessment studies, the project can be started as an extended pilot or demonstration stage to gain as much information as possible to propose an optimal design, skipping (or minimizing) lab-scale experiments and numerical model studies. In such complex cases, the project will be operated by changing parameters based on continuous monitoring of the process; optimal conditions will be determined based on this data. There are two reported CO_2 applications that are good examples of this kind of application: the (1) Bati Raman (Sahin et al. 2008) and (2) Wasson Denver (Bullock et al. 1990; Tanner et al. 1992; Hsu et al. 1997) projects. Although simulation (sector modeling) and laboratory experiments were used for initial assessments, the project development was based on the field data gathered and re-engineering attempts. Hence, "dynamic" design with continuous surveillance is essential in many EOR processes and this fact should be considered in the initial design phase. The infrastructures and other investments should be made taking into account possible alterations in the process to be addressed in the future.

For example, the Bati Raman CO_2 project started as a huff and puff based on initial experimental and computational studies. In a short period of time, having a breakthrough of CO_2 from neighboring wells during the soaking/pressurizing period due to extreme heterogeneity, the project was converted to continuous injection with a "random" pattern. Although this decision was difficult to make as the process was not run in an optimized way, it turned out to be a profitable application in a short period of time (Sahin et al. 2008).

Another good example of dynamic design is the Wasson Denver Unit CO_2 flood, the largest CO_2 injection project in the world in 1983 (Bullock et al. 1990). It started as continuous, evolved to a WAG type injection (Tanner et al. 1992), started expanding in 1989 and 1990, then began to decline after ten years in 1994. The performance was different in different areas of the heterogeneous carbonate reservoir. Re-designing concepts and other development options were evaluated using sector simulation attempts based on initial observations, performance analyses, and continuous monitoring of the well performance (Hsu et al. 1997). Shortly after the inception of the project, previously closed water injectors were converted into producers and flood patterns were regularized with infills, which became an inverted 9-spot injection pattern (Fox et al. 1994). Initially, water was produced with little oil due to the conversion of water wells into injectors, but as the CO_2 injection progressed a growing oil bank was pushed to the converted wells resulting in an increased oil cut.

The critical part in these redesigning practices was waiting patiently until the oil production started. As the flood matured, 9-spot was observed to be underperforming, especially in the eastern part of the field. Additionally, well problems such as plugging and freezing at the surface were faced (Thai et al. 2000). In 1995, a re-alignment was implemented with four infills drilled, and then six producers were converted to injectors resulting in two line drives and three semi line drives. Incremental production reached 6,600 bbls/d and total production turned out to be 25% more than the forecasted value. As reported through sequential publications, periodic analyses and continuous monitoring were essential in determining the best injection strategy based on field demonstration; this method might be more useful than 'initial' simulation studies or small-scale pilots in decision making. The Wasson CO_2 project example clearly indicates the importance of being flexible and ready for any changes during the course of a project.

As seen, continuous monitoring and surveillance is essential in dynamic design. This involves planning what to do and how to do based on observations (see Fig. 10 for the step-by-step development stages), and more importantly when to take action. This need for monitoring has to do with the human factor; therefore, experience plays a critical role in this as discussed in the next section.

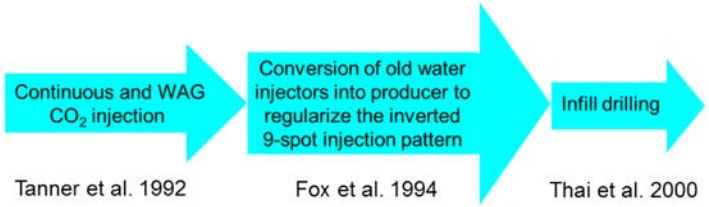

Figure 10—Periodic evaluation of the Wasson Denver CO2 injection project (largest in the world).

Risk-taking:

The risks involved in EOR projects are due to the technical factors/uncertainties listed above (and many more can be added) and equally important volatile oil prices. Depending on the company size, type, and location, political, legal, and operational issues, the risk might be magnified. Then, the human factor comes into play. Who would take such risks and for what reason? It would not be an overstatement to say that no individual would be willing to take responsibility in initiating, proposing, and decision making in a project, especially in small- or mid-sized companies. International (i.e. major) or national oil companies can distribute the risk within the company, as well as having less problems finding the best experts and experienced executors in specific EOR subjects, thus reducing the option of finding a "champion" to take over the great portion of the risk, initiate, and lead the project.

Based on the above analyses and listed parameters affecting the decision and implementation of EOR applications, one may raise more specific questions as to why EOR applications are not at the desired levels despite huge potential. After the questioning/answering in the next section, examples will be given in the following section as to what makes EOR applications a success.

Questions as to why EOR projects are not at the desired level

In this section, the points that have been raised and discussed so far are compiled and listed in a compact form covering all possible relevant aspects of the main theme: "Why are the EOR recoveries and a number of projects not at the desired level?" The points and arguments raised were delineated after posing said question, and each question brought up further complementary questions, some of which are answered in this section while others are left to the subsequent section in which field examples are used to provide clearer answers with real-life supportive data.

What drives EOR applications, technology or economics? Is it all about economics? How about technical deficiencies?

Each EOR project is unique. Technical success of one method in one field may not be the same as another field, even if the fields are geologically identical. Thus, they require different technical assessment for the same EOR application. Once the technical viability is proven, the next question comes: Is it economic?

The main criterion in EOR projects is the economics of the project—much like any other type of engineering application. In the beginning, any project is "uneconomic" in "almost all circumstances", but an engineer's job is to make it economic, or at least to determine under what conditions it becomes an economic project; as well, the engineer must optimize the process under the given conditions (e.g. limited supply of EOR agents, minimum cost the company can tolerate, etc.).

The definition of "economic" is a vague issue (or term) in EOR investments. This definition may change based on the size and type of company. The common term is "profit" in any type of EOR (or engineering) application, but the amount of profit and breakeven times as a measure of economics of the project is variable. Big-sized companies may not assume the project to be economical enough to go for an EOR application as they are interested in high-profit, short-term projects. Alternatively, the project may not be assumed economical for small companies if the profit is long-term (even if the profit is high).

Hence, what is the main criterion in setting the objective function? Is it only the NPV? Or, is time a critical factor (i.e. time to reach the breakeven point or continuity of profitable region) to be considered? Some projects could be time sensitive (small- or mid-sized independents) and may not be called "economic" if no profit is made as soon as the injection is started, while others may afford delayed (or long-term) profit (NOCs or IOCs). Therefore, using the "economics" of a project as the main criterion in the beginning may result in an underdetermined assessment of the project thus causing rejection of the method. The feasibility of a project is a broader concept obviously containing not only the basic principles of economic analysis by determination of NPV, but also other analyses such as short-term and long-term benefits/profits, variability in breakeven time, coping with variable oil prices, and other negative factors during the course of the project.

Has sufficient attention been given to the "cheapest" EOR methods (air injection or microbial)?

Air is the cheapest EOR agent and a substantial 'research' effort has been made over a long period of time to carry it over to field-scale projects, but applications are limited. Manrique et al. (2010) reported that (Fig. 4 of their paper based on 2008 Oil and Gas Journal annual EOR survey) air injection projects are an increasing trend in the USA, but numbers still only hover around 20 projects. Heavy-oil and bitumen recovery by air injection relies on in-situ combustion (HTO) and it is a widely accepted fact that controlling this process (advance of the front) is a critical limiting factor.

More recently, several studies showed potential using options and suitable conditions for the safe application of air injection as an LTO application (Mayorquin and Babadagli 2015; Mayorquin et al. 2015; Mayorquin and Babadagli 2016a-b), even at pressure and temperature values close to atmospheric conditions, like those found in shallow reservoirs (Soh and Babadagli 2018; Soh et al. 2018).

The same can be said for microbial injection as a "cheap" method (one of the cheapest additives to water), a method of which has no application in the world, according to an Oil and Gas Journal survey done in 2014 (Kootungal 2014). Why did this method not show progress despite considerable research (Deng et al. 1999; Jackson et al. 2010) and some field applications (Sheehy 1990; Deng et al. 1999)? It is not the economics, but the technology development, as it requires unique research for any type of oil or field because compatibility of the injected materials with the reservoir oil is a case-specific issue.

Why are we afraid of miscible processes that yield high recoveries in the long run?

Miscible gases or solvents are the most expensive EOR agents, but they expectedly (at least theoretically) yield the highest recovery among all other displacement methods if all the conditions are met (e.g. a good contact of solvent with oil, etc.). Depending on the reservoir type and processes involved, continuous or cyclic (huff and puff) injection, and design, they may be profitable in the long or short run (Cao and Babadagli 2018a-b). The correct time to start a project is highly critical in miscible displacement processes and to improve the potential of the field and extend the production life economically, one may start the EOR application in the early stages. Good examples of these kinds of applications are the Weyburn-Midale CO_2 injection (Beliveau 1987, 1993), the North Sea (Zhang et al. 2013) and Prudhoe Bay miscible injection (McGuire et al. 1999), and lastly the McGuire and Holt (2003) projects that started shortly after waterflooding. Hamedi-Shokrlu and Babadagli (2015) and Cao and Babadagli (2018a-b) attributed the success of these projects to avoiding any negative effects of high water content by minimizing the waterflooding duration before the inception of miscible flooding in these types of water-wet (sandstone) reservoirs.

Also note that miscible injection (or any other gas injection process) is the only method in which we can recycle the injected material (except water injection, which often requires a substantial cleaning process). The opportunity to recycle might be another reason for many successful gas (miscible or immiscible) injection applications thus motivating companies to consider this method as an EOR process (Blanton et al. 1970; Meltzer 1974; Hansen 1977; Christian et al. 1981; Griffith and Cyca 1981; Rowe et al. 1982; Langston and Shirer 1983; Kumar and Eibeck 1984; Derochie 1987; Frimodig et al. 1988; Chou et al. 1992;

Ring and Fox et al. 1994; Smith 1995; Harpole and Hallenbeck 1996; Gunawan and Cale 1999; Kane 1999; Edwards et al. 2002; Lawrence et al. 2002; Sahin et al. 2008; Al-Bahlani and Babadagli 2011, 2012; Al-Gosayir et al. 2013, 2015; Mohammed and Babadagli 2015; Rangriz-Shokri and Babadagli 2016; Moreno and Babadagli 2017; Cui and Babadagli 2017).

Regardless of all these points, gas injection (primarily miscible CO_2) is still the most common EOR technique (Fig. 4a) overtaking steam injection in the last decade (Figs. 3 and 4a). As well, the share of more expensive hydrocarbon gas injection in this method could be considerably higher.

Why have field-scale chemical injection applications been meager compared to the remarkable efforts put in research? Is it simply because of the cost of injectants?

Although some field-scale applications were reported in the 80s (Fig. 3), the applications of chemical injection methods were almost nil around the 90s (Fig. 4). Although this can be attributed to the bottomed oil prices in the mid-80s (and the late 90s) and the excess cost of injectants with high consumption in the reservoir, would it be possible to consider that there are other technical reasons behind this, thus causing recoveries lower than expected from the applications in the 70s and early 80s? In chemical injection, laboratory results are typically very promising with good recovery data (Maerker and Gale 1992) but in the field-scale experimentations, pilots are not at the expected level (Bragg et al. 1982, 1983) due to possible reasons of chemical loss due to chemical degradation, adsorption despite local incremental recoveries being high. Also, core-scale experimentation cannot be useful in assessing the degradation and adsorption of chemicals on 2-10 inch core samples. The fate of chemicals is more complex in harsh reservoir conditions (high temperature, high brine salinity and hardness, poor reservoir permeability, complex heterogeneity, and duration of exposure of chemicals to this environment). These are experimentally difficult to analyze, thus limiting numerical verifications.

On the other hand, successful applications of chemicals as tertiary recovery (Fig. 7) as well as heavy-oil recovery (Delamaide et al. 2014) were reported in different time periods including a few sudden drops in oil prices. Tertiary recovery applications reported in Fig. 7 are either at the pilot stage (Koning et al. 1988) or performed in the 70s or 80s as small projects (Danielson et al. 1976; Maitin and Volz 1981; Saad et al. 1989; Bae 1995).

It is debatable what makes these projects successful and thereby continuous. Is it the economics due to high oil prices in early 80s or technical success by the efforts put in supporting research and/or proper design? Further questions are to be asked as to the reasons behind the successful application of chemicals in heavy-oil. Currently, Daqing oil field in China is the only large-scale chemical injection that is ongoing and independent of changing in oil prices, and has been since 1994. Another example of sustainable chemical flooding is the Pelican Lake ASP flood in Canada ongoing over the last decade. Note that these are operated by big companies that can afford long time investments and low profit margins. Especially, the latter project may not yield high recoveries that could be obtained from steam injection methods but it may be more efficient due to reduced cost of investment and operational risks involved. Hence, even if the profit is low and gaining is slow, it is less risky and safer operationally than steam flooding (also considering the other limitations of thermal methods such as effective use of heat energy and heat loss issues).

Can we accurately assess EOR performances for unconventionals using conventional continuum models, or should we consider EOR as a multidimensional process in complex geological media to be modeled by an "energy-in energy-out" (like steam injection cases) approach?

As discussed in the previous section, limitations of numerical simulators in modeling complex EOR processes could be a reason for delayed or unhealthy decision making. Hence, the question is whether or not we can accurately model and assess the EOR for unconventional or heterogeneous systems using conventional simulators based on classical theories (frontal displacement, continuum models) just by changing the reservoir properties. Is the alternative more simplistic approaches such as "energy-in energy-

out" (like the steam injection case) or the voidage ratio (Delgado et al. 2013; Vittoratos and Kovscek 2017) to model such a multidimensional process in complex geological structures?

Why is the incubation period (research to field) of EOR projects so lengthy?

It is a well-accepted fact that the incubation period (from research to field-scale development) of an EOR method is unnecessarily too long, typically varying between 3.5 to 6.5 years (Fig. 8). There could be many factors controlling this length such as the complexity of the method, the involvement of different phases (lab work, field work), and the infrastructure preparation. One more important factor at the late stage of initial development, however, is undeniable: receiving the EOR response in a field application may take too much time at the pilot, demonstration, or full field development stage. As can be inferred from Fig. 5, comparing the number of project (red) and total production rate (blue) lines, despite the steep decline after peaking number of projects (around 1986), shows the total production rate increasing and not showing a significant decline. The period between peaked number of projects (1986) and the time that stabilization for the total project rate is reached (1992) could be an indication of this "late response" (indicated by arrow) of the field to the EOR application from the beginning. These types of long-term investments are risky with much uncertainty mainly due to unpredictable oil recovery response in the short-term and other less common reasons such as political and economic instabilities.

Can this incubation period be shortened? The Mukhaizna field in Oman is a good example of this. A highly experienced company in steam injection through worldwide experience took the asset and started injecting steam in 2007, drilling a substantial amount of vertical injectors and horizontal producers (Malik et al. 2011), thus skipping or minimizing initial stages indicated in Fig. 8 (fluid and core tests, pilots, etc.). The field showed a response to the EOR method in a relatively short period of time. This is mainly due to proper initial design (selection and alignment of horizontal wells), good reservoir management, and experience gained by the operating company on steam injection over decades thus making risk-taking possible.

Has the industry been too fearful in implementing EOR projects due to the unforeseeable behavior of oil prices?

This question constitutes one of the main themes of this paper. Is it all about oil prices or are there other technical (or economic/political/humanitarian) issues involved? And, has the industry been too fearful in triggering EOR projects due to periodically occurring unexpected sudden drops in oil prices as experienced several times since 1980?

The other seven questions raised in this section are related to technical rather than economic issues. But, this factor may play a critical role in attempting any EOR development projects and it should be taken into account in our analyses.

Do we often need a champion (risk-taker) within companies to promote new ideas and the implementation of EOR projects?

In conjunction with the point raised in Question 7 above, one may further question whether such long-term and risky investments need properly organized teams or even a "champion" to lead the work. This "champion" could be the management, state, agencies, a unit in the company, or even a single person, depending on the size and type (IOC, NOC, independent) of said company. These "risk-takers" may lead the whole initiative but risk distribution could be a better and more encouraging option.

Efforts paid for the SAGD process in Canada is a good example of this. After being invented and patented in the 80s, and studied at a lab-scale (Butler 1994, 2004), the field-scale development and implementation of SAGD was made possible through the UTF (underground test facilities) project (Edmunds et al. 1989; Mukherjee et al. 1994). This field-scale experimentation project was triggered by a government agency, Alberta Oil Sands Technology and Research Authority (AOSTRA), and the risk and cost were shared by participating oil producing companies including the one that owns the patent. Today, SAGD comprises

almost half of Canadian heavy-oil bitumen oil production through more than 1500 well pairs (Farouq Ali 2013). A similar government led effort is the Department of Energy (DOE) support to universities and companies by the federal government of the USA in the 1980s to conduct research on EOR leading to field-scale application.

One may evaluate the risk distribution considering potential "bodies" involved in the EOR processes at different stages. Fig. 11 illustrates the involved bodies at different stages of EOR technology development. Typically these bodies are independent of each other and they need to be "cemented" through different organizations. This brings up the next question: "Who should take initiatives to shorten the journey from the idea, research, and profit stage; service companies, majors, nationals, universities, government agencies, or research centers?" The "idea" might come from all possible bodies, but research (especially fundamental) can be conducted or supported by only a few of them. New technologies can be developed in all of these bodies (usually it is not in the mandate of private companies), but private companies have the potential to commercialize them. As seen, even in the pre-implementation stages of EOR, many different bodies play a role, six of which are listed in Fig. 11. Co-ordination of these bodies to develop new ideas and technologies could be another dilemma and cause in the delay of field implementation (which is also exhaustive through capital investments and infrastructure). The cases of DOE and AOSTRA mentioned above are good examples of this co-ordination done by government agencies. An alternative way is to establish alliances like the Petroleum Technology Alliance Canada (PTAC) or Canada's Oil Sands Innovation Alliance (COSIA) in order to share the risk, facilitate the technology development, and carry the technology at the commercialization stage.

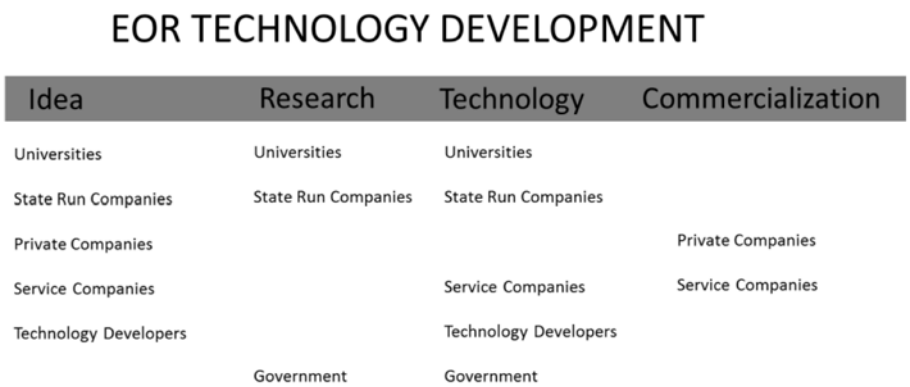

Figure 11—Bodies involved in EOR technology development and their roles at every step of the process.

Selected successful and sustainable EOR project examples

In this section, selected EOR projects that were run sustainably for a long period of time—regardless of the fluctuations in oil prices—were evaluated. Through these cases, the question that has been raised multiple times throughout this paper as to whether EOR projects are strongly dependent on oil prices will be answered.

Selected EOR applications of different methods are listed and summarized in Table 1. In this table, project durations were included to give an idea about the sustainability against changing oil prices. Also, included is the company type and size, which plays a critical role in EOR project implementation. End dates were given based on the reporting time (publication date) of EOR projects. If the exact end date is not known and the project is ongoing at the time of results were reported, an "at least" condition was put. The most recent information about the current status of these selected EOR projects is given by IEA (McGlade et al. 2018). The EOR projects reported as "ongoing" in this source are marked by "Y" in Table 1 (column "Current Status by IEA"). Those that are not included in this report are assumed to be terminated and marked by "N" in the same column.

Obviously, these projects were reported economic in all cases or assumed to be economic as they were continued over the low oil prices periods. If the exact termination time is given, it is usually not very clear as to why they were terminated, i.e. the technical (lowered recovery factors) or economic (slumping oil prices) reasons or due to management issues. If a project was continued despite significant drops in oil prices (e.g. 1986, 2008, 2014, etc.) as shown in Fig. 12 (circled periods), it is assumed to be technically and economically successful and included in Table 1 regardless of the reason for termination (if terminated). After evaluating the field cases given in Table 1, the answer to this question is sought: "Why are these EOR applications successful and sustainable regardless of the fluctuation in oil prices?" in the subsequent section.

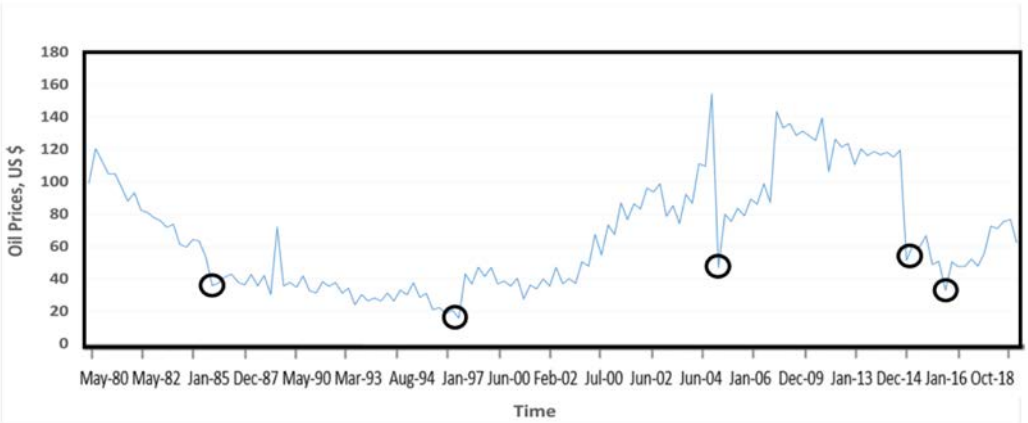

Figure 12—Oil prices (inflation adjusted) change in time and serious (circled time periods) drops causing potential delays in EOR projects.

Gas injection applications

The highlighted projects (G1 through G7) are continuing as per the recent reports and to our knowledge. No documentation was available for the current status of the remaining projects (G8 through G19). According to Koottungal's (2014) EOR survey, some of the projects are still ongoing based on the start date reported; Sacroc (G15), Slaughter (G12), and Wasson Denver (G9) start dates were reported as 1972, 1984, and 1985, respectively. In the same survey, gas injection projects reported with a start year dating back to the 1980s and 1990s are still ongoing. Manrique et al. (2007) reported around 60 CO_2 floods in the USA all in carbonates, mostly in Texas. Most of them are well-known projects as also listed in Kootungal (2014) and fall into the downturn periods indicated by circles in Fig. 8.

Steam injection applications

Many well-known steam projects in California with start dates varying between 1965-1995, mainly Midway-Sunset field and Kern River (S6) in Table 1, and recently started projects (between 2002 and 2011) are still continuing. Chu (1985) also listed steam injection projects worldwide, with start dates varying between 1956 and 1977 (all in the USA, except for a few in Venezuela, one in Germany, and one in the Netherlands). There is an obvious break in the late 90s and early 2000s likely due to the downturn in oil industry or recession period in the general economy, country, or worldwide.

The biggest steamflooding and CSS projects listed in Table 1 (S1, S2 and S3) are included in the analysis as long-term ongoing projects (over decades) regardless of the fluctuations in oil prices.

Air injection applications

Chu (1983) provided air injection projects—not all of them as successful—starting dates varying between 1956 and 1977 (all in the USA, except a few in Venezuela and Romania, and one in the Netherlands) of which several cases are included in Table 1 (A3 through A7). A significantly small number of projects (a total of 12) currently running have been reported by Koottungal (2014) for this cheapest injectant (Figs.

3–4). The long duration ones are A1 and A2 projects in Table 1, which are still ongoing and will be included in further analysis of why they were sustainably continued later (A1 was started as a big company and taken over by a mid-sized one, while A2 was operated by a NOC taken over by a mid-sized company later on).

Chemical injection applications

The "popularity" of chemical injection processes date back to the 60s and 70s (Fig. 3), followed by a stagnant period (between 1990 and 2000). Although not as popular as in the 1980s, chemicals gained a degree of attention after the 2000s. The most sustainable six projects are highlighted in Table 1. Interestingly, they belong in the heavy-oil category (chemical floodings in Canada, Delamaide et al. 2014, listed as C1 through C5) with one exception (Daqing field listed as C6).

As seen through cases C1-C21 most of the projects were started and completed within the period of 1970-1990, said projects owned by big companies (C7-C12 and C19-C21) with one exception (C11). Newer projects (C13-C17) were also long lasting but were generally run by mid-sized companies (C13, C14, C16, C17) and an NOC (C15). Within the period of the 60s through the 80s, IOCs (companies like Marathon, Texaco, Exxon, and Shell) developed a number of micellar/polymer projects, and no chemical projects conducted by IOCs (or even smaller companies) are reported in the USA (Koottungal 2014).

Polymer is applied more than any other chemicals as of today (C1-C6 in Table 1). Seright (2016) documented recent polymer applications and they all come out of the USA. Applications in China include the most popular one recently—Daqing (C6 in Table 1) (Wang et al. 1995, 2008; Dong et al. 2008), as well as others with a starting date of 1993. Other projects in China (Kang et al. 2011), Argentina (Buciak 2015), Suriname (Manichand et al. 2013), Angola (Morel et al. 2012), Brazil (de Melo 2005), and Oman (Thakuria et al. 2013) started between 2001 and 2008 (Sheng et al. 2015) and run at least three to seven years field-wide. Considering the duration period of these projects, they can be assumed to be technically and economically successful and they were "alive" during the erratic oil prices periods (between 2000 and 2010).

Others methods (microbial, electrical/EM heating, sonic, nano-particles) and EOR in unconventionals

No large-scale field applications have been reported for other EOR methods historically. Despite being under consideration over decades with substantial lab trials (Jackson et al. 2010) and the relatively inexpensive technique, microbial injection has been limited to small- (pilot) scale applications (Sheehy 1990; Deng et al. 1999; Jinfeng et al. 2005, Havemann et al. 2015). The same can be said for electrical heating (Bera and Babadagli 2015) and sonic methods (Hamida and Babadagli 2008; Naderi and Babadagli 2011a-b). Nanomaterials are yet to be considered for large-scale field applications (Fletcher and Davis 2010; Skauge et al. 2010; Khavkin 2014).

Also, it is difficult to include the "philosophy" of unconventional EOR in this paper as no field trials have been reported yet. The economics could still be an issue in these types of applications as almost all EOR processes in unconventionals are associated with hydraulic fracturing, of which adds to the total cost. Beyond this, applicability of other techniques—except gas injection—is technically limited. Hence, the most expensive techniques, solvent injection (Alharthy et al. 2015) or chemical additives (Delamaide et al. 2014), are thought to be the only choices. To date, the most commonly suggested method is CO_2 injection (Joshi 2014; Alfarge et al. 2017a-b-c-d; Jin et al. 2017), a primary method unlike EOR, for conventionals with a few pilot trial exceptions (Alfarge et al. 2017a). Unlike EOR applications in conventional (mature) fields, of which are potential to proven technologies, unconventional (tight sand, shales) require additional IOR-EOR efforts from the beginning. Yet, suitable technology modifications and performance estimation models are yet to be developed and fracking is a must in these applications (Joshi 2014; Jacobs 2015).

Furthermore, Manrique et al. (2007) reported around 55 chemical floods in the USA all occurring in carbonates, which is also uncommon when considering unconventional EOR practices. They were run

between 1980 and 1990 and terminated after 1990, likely due to the bottomed oil prices and incompatibility (technical issues) of the methods in carbonates. As of today, no chemical injection in the USA was reported except in three very minor projects (Kootungal 2014).

Now, it is time to repeat the same question in light of the above summarized information and analysis: "Why are some EOR applications successful and sustainable regardless the fluctuation in oil prices?" Are these fields simply just suitable to the selected method (as described by Taber et al. 1997a-b)? Were they started at the right time after primary or secondary recoveries (Weyburn CO2, Case G1 in Table 1) or North Sea and Prudhoe Bay miscible floods (Cases G4, G5, G6 in Table 1)? How about waterflooding histories in these fields, was it converted from waterflooding to EOR at the right time (Duri field steamflooding, Case S1 in Table 1)? Are they secondary, tertiary, or even primary (like the Cold Lake steam injection (Case S2 in Table 1), or is it only the economy driving any EOR process resulting in the success and continuation of these projects only in the high oil prices periods? If so, how come all the projects evaluated above became sustainable and continued during the downturn periods (see circled periods in Fig. 12)? Or, is the reason for sustainability or success of these EOR projects because they are owned and run by IOCs and big-sized or major companies? Or is the success behind due to the good initial design and continuous monitoring to re-engineer the project periodically changing injection/production strategies (Wasson Denver Unit CO2, Case G10 in Table 1)?

Just note that there are cases of EOR where it is applied as primary as there is no choice to produce oil (primary or secondary, i.e. waterflooding conditions). Both Canadian and some of the Californian extra heavy-oil cases are some examples of this category. Hence, they are also included in this analysis as "EOR" as they are investment and operation intensive projects.

Possible reasons that make these EOR projects a success despite fluctuating oil prices

Based on the above listed questions and reasoning, the factors affecting the success are listed here and tabulated in Table 2 in Appendix 2. Example field cases given above and in Table 1 (highlighted) were used to analyze each of these success criteria.

Field (asset) size

If the asset (field size) is big, then in the long run it makes profit even if the CAPEX is high. Canadian oil sands are a good example of this (even the surface mining and extraction units). SAGD is an expensive technique due to both high CAPEX and OPEX, but it comprises a great portion of in-situ heavy-oil production in Canada (Farouq Ali 2013) despite recent downturns in oil prices. Although the profit margins are small at the current oil prices (US $50/bbl in 2019), the projects have continued in the downturn times. They were affordable as the operators are large-sized companies that can tolerate a marginal profit for a period of time as long as the asset size is big, yielding a high amount of recoveries. In support of this argument, smaller sized projects of in-situ (and even oil sands extraction) were sold to other big-sized companies during the downturn time, even if the withdrawing companies were big-sized and IOCs.

Hence, field (asset size) is critical and these big projects requiring high initial investments with some risks in such giant units can be owned by IOC, major (big-sized) companies. A controversial argument can be also made. With the same logic, i.e. if the asset size (and thereby company size) is big, projects can be managed through the downturn time, one may question why the "carbonate version" of the Canadian bitumen (the Grosmont unit) has not been successful even if the reserves are huge (Edmunds et al. 2009; Naderi et al. 2013; Mohammed and Babadagli 2016) and the owners are majors (the same ones having assets on the oilsands part) companies. The reason behind this is the limitation of suitable technologies (Jiang et al. 2010a-b; Naderi et al. 2013; Hosseininejad Mohebati et al. 2014) applicable in this very complex geology. This requires serious efforts in designing a project and continuous monitoring/re-engineering (Naderi et al.

2013; Pathak et al. 2013). In a nutshell, EOR still needs technology development for special cases (bitumen in heterogeneous carbonates or other unconventionals). Note that the success of SAGD during negative economic conditions is not only due to asset or company size but remarkable efforts put on technology development in the 1990s supported by provincial government (AOSTRA).

Company size and type (nationals, majors, independents)

As indicated above, big-sized companies (IOCs and NOCs) can afford long-term projects and investments (big CAPEX or OPEX) so that they can run EOR applications in large assets. Does that mean that EOR practices can be only big company business? The selected (or reported) long lasting and successful EOR projects in Table 2 are run by IOCs, big-sized companies, and rarely NOCs. That is true in a sense that small-sized companies may avoid long-term investments due to uncertainty and the volatile nature of the oil industry. There are, however, small-sized companies with successful operations (C2 through C5 cases in Table 2). Certain methods requiring substantial CAPEX such as steam injection (also requires high OPEX) or CO_2 injection (if the secured source is not available) may not be suitable at first sight for small companies. But, certain cases (G13, G21, A4, A6, S5, C13, C14, C16, C17) in Table 1 can be given as examples of successful EOR applications. Although some of them date back to 1960s and 1970s, which may not be comparable to last four decades of oil prices situation starting 1980 crisis (like G13 and S5 cases), others were operated even through the bottomed oil prices periods.

There are other documented success cases of EOR in literature that are not included in Table 1. For example, Blanton et al. (1970) reported a propane slug injection case with economic success for a small-sized company. Boukadi et al. (2005) and Babadagli et al. (2007) showed that nitrogen injection could be viable for a small field owned by a small company with very limited investment even though the OPEX (N_2 cost) could be relatively high. Once again, the main problem with small-sized operating companies is the uncertainty in the continuity of business in oil industry in general and the risks involved due to this fact that makes difficult to find risk-takers (champions).

Availability of 'cheap' EOR agent

Even if many of the applicability criteria are met in order to have a successful application, the availability of the agent could be a serious restriction. The sustainable supply of CO_2 and industrial gases (LPG, N_2, or naturally obtainable gases like methane), and even water (not available everywhere) could be a concern affecting the decision of any EOR method. Excluding air, yet a "free" substance, all the injectants could be problematic in terms of secured availability. The success, to a great extent, of most applications listed in Table 2 is due to a sustainable source of injectant. Especially the CO_2 cases that were chosen in this table, based mainly on the secured availability of the source (G1-G3, G6). Acid gas was produced in a neighboring gas field with methane and to dump it, an EOR application in the Zama field was developed (G2) (though this method was technically suitable for the field yielding miscible flooding by help of high H_2S content of the acid gas). The Bati Raman case (G3) represents an opposite example due to technical suitability (incompatibility of injected gas with the oil resulting non-miscible displacement). A natural source of CO_2, which is only 80 km away from the field, has supplied CO_2 for more than 30 years and even though technical suitability was questionable (heavy-oil which is not miscible with CO_2 and extremely heterogeneous reservoir), the project has been run due to continuous supply of CO_2 at low cost. In case of Ula miscible gas injection project (G6), it was reported that the gas to be injected was secured before embarking upon the project.

Many of the CO_2 cases in the USA (typically in west Texas) were operated due to naturally or industrially available CO_2 (Kuuskraa and Wallace 2014). Availability of the CO_2 source is more critical than technical, suitably unlike many other methods such as steam or air injection as CO_2 is one of the rare injection materials that is compatible with many different reservoir and oil types. To show how CO_2 injection could

be independent of the fluctuations in oil prices, Manrique et al. (2007) plotted the number of CO_2 and chemical projects and oil prices versus time. Fig. 13 shows their comparison stressing the independency of CO_2 projects on oil prices unlike chemical flooding. Despite two significant drops in oil prices (1986 and 1998), CO_2 projects in the USA increased. To a great extent, this could be attributed to a sustainable (and possibly cheap) supply of injectant (Kuuskraa and Wallace 2014).

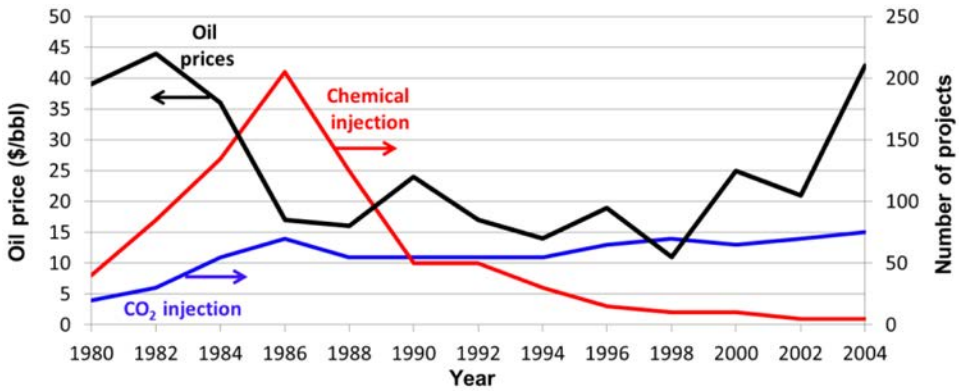

Figure 13—Number of chemical and CO2 injection projects between 1980 and 2004, and corresponding oil prices (regenerated using the data in Fig. 3 of Manrique et al. 2007).

High oil prices during the course of an EOR project

Exact costs and profits of EOR projects are hard to obtain due mainly to confidentiality. In many cases, the cost/profit is implicitly disclosed using different indicators such as steam-oil ratio or unit technical cost. Therefore, it is difficult to make assessments purely based on the economics of the projects. However, we can assume that continuation of the project in the long run (especially covering the decline period in oil prices as marked in Fig. 12) is an indication of economic success of the project as explained above.

Also, profit margins change company by company; for example, IOCs can handle big investments (CAPEX), but expect bigger gains in the long run, while independents target short-term revenues. In the case of SAGD operations in the Athabasca region, profit margins might be extremely low in downturn periods (like the situation occurring in the Canadian industry after the 2014 crisis). NOCs are more tolerant to delayed breakeven points as long as the investment brings big revenue in the long run.

The 'decision matrix' given in Fig. 14 considers four possible scenarios of cost-profit from existing (unchangeable) conditions such as company size and controllable parameters like the degree of risk-taking for an EOR project. One of the scenarios in this 'decision matrix' given in Fig. 14 might fit into projects even though the cost is not a constant parameter and may vary over the course of the project. The ideal situation is Scenario 4, made possible for the long run in big fields of which can be operated by IOCs or big companies (Cold Lake case, S2). It may not be "fast" recovery and "quick" profit but the total profit in the long run can make the process viable. The same can be said for Scenario 3, in which the high cost can be tolerated by only big-sized companies. This is all determined by the existing oil prices, which are volatile and reaching minima every ~10 years periodically (Fig. 12). The Handil field (G8 in Table 1) gas injection was a three-year project but was declared to be economic with exact cost and profit values; the report included data until 1998, corresponding to the lowest oil prices term since the 80s, but it is not clear whether the project was continued. Otherwise, it remained economic even in the relatively low oil prices term between 1995 and 1998.

What you can do / Company size restrictions	High risk	Low risk
Small Companies	Scenario 1 Low cost – low recovery	Scenario 2 Low cost – high recovery
Big Companies	Scenario 3 High cost – low recovery	Scenario 4 High cost – high recovery

Ultimate goals:
How fast can I make profit?
How can I maximize my total profit over time?

Figure 14—"Decision matrix" composed of four possible scenarios of EOR projects.

Scenarios 1 and 2 are more applicable to small- or mid-size fields, with short- or mid-term investments. This determination is based on company type, as it is the company's decision to fix the minimum profit to make an early breakeven rather than maximizing the total profit in the long run. Chemical processes given as cases C1 through C5 are good examples of low cost high recovery (chemical additives are costly and recoveries are low due to an unfavorable mobility ratio in these heavy-oil fields). A low cost, low recovery example is outlined in A1 (big company), A4, and A6 (small companies).

Seright (2016) and Sieberer et al. (2016) discussed the economics of polymer flooding. Based on either the economics or oil prices, polymer slugs could be shortened (continuous monitoring and re-engineering), adjusted to the optimal well distances (initial design), and injectivity monitoring (optimal polymer viscosity/concentration, which is variable throughout the project (continuous monitoring and re-engineering) could take place. The success (continuity over the low oil prices periods) in these heavy- oil fields and sustainable giant field cases such as the Daqing chemical injection, could be attributed to this optimal and "dynamic" design.

Low CAPEX / low OPEX

In conjunction with the above analysis, initial and continuing costs (CAPEX and OPEX, respectively) have to do with company size. The cost is not a constant parameter and may vary over the course of the project and profit might come in later due to delayed breakeven times. Typically, initial costs (CAPEX) are fixed (e.g. infrastructures, surface/injection facilities, pipelines, boilers, pumps, etc.), but they cover a relatively smaller portion (30-50%) compared to OPEX (50-70%). To offset the high cost, recovery should be high (Scenario 4 in Fig. 14) if the CAPEX could not be minimized.

CO_2 is a CAPEX intensive application due to pipeline distribution systems and special well completions for injectors, assuming that the supply of CO_2 from natural or industrial sources are cheap; chemical injection is an OPEX intensive process (usually waterflooding facilities exist). Hence, in the case of CO_2, once the infrastructure has been established, sustainability is easier even if the oil process drops (Fig. 13). This corresponds to Scenario 2 (Fig. 14) in the long run. One exceptional case is G3 (Bati Raman CO_2 injection) in which a substantial amount of injectors were needed to minimize the well distances field-wide, as immiscible CO_2 injection in a heavy-oil field would not promise high recovery factors (over the 30 year period recovery factor purely due to CO_2 role on the maintenance of reservoir pressure and swelling effect was around 4-5% OOIP). However, the cost of—naturally obtained—CO_2 was low with the exception of the initial investment (80 km pipeline, several CO_2 producing wells, and distribution facilities in the field). OPEX (continuous monitoring and re-engineering) reduction is possible through the optimization of artificial lift, CO_2 delivery

systems (or steam or other gases), and tackling production related problems (e.g. emulsification, asphaltene precipitation, etc.) (Babadagli 2019).

Technical suitability of technology

Certain EOR methods, given in Fig. 1, could be a perfect fit for the reservoir by the 'book definition,' meaning they are meeting many criteria applicable in this field (Taber at al. 1997a-b). In this case, technical success is warranted, making it easier to achieve economic success. Prudhoe Bay miscible flooding (G4), Duri field steam flooding (S1), Kern River steam injection (S4), or Suplacu de Barcau air injection projects (A2) are good examples of said successful cases (Table 2). Their continuity over decades is also a good indication of the technical suitability resulting in either a short- or long-term run as well as economic success.

Certain reservoirs may not be suitable for any EOR method by the 'book definition,' even in waterflooding (fractured carbonates or heavy-oil cases given in C1-C5 in Table 1); the best option is chosen based on the existing conditions, despite the method effectiveness not being very high. As mentioned earlier, often times, more than perfect suitability (G4-G6) and availability of the injectant is considered in the decision making process (G1-G3), having no other option (S1, G8, G10). For example, CO_2 injection in fractured carbonates (Weyburn/Midale and Bati Raman cases) may be the best option compared to others, even if it is not a perfect fit.

Good understanding of reservoir geology and complexity

There is no question that a clear description of reservoir geology is key in designing and operating in the field. The cases of steam, chemical, and air injection given in Table 2 were conducted in relatively homogeneous reservoirs; hence, a detailed geological description may not be a critical issue. This, however, may not be quite possible in many cases if the field is complicated—like carbonates (note that most of the US CO_2 floods are in carbonates, Manrique et al. 2007). The Cantarell (G10) field is a good example of this, as this giant offshore field, severely fractured with an average thickness of 1,200km, is difficult to characterize. This fracture may play a critical role in designing N2 flood, of which requires average matrix size, fracture orientation, and density data. The Weyburn (G1 in Tables 1 and 2) case, however, represents a good quality of reservoir characterization efforts using the history of the field data and through the acquired data from extensive pilot tests (fracture orientation and density data) (Beliveau 1987; Beliveau et al. 1993; Bogatkov and Babadagli 2009a-b). This particular EOR project case stresses that reservoir characterization is critically important in operating the process rather than understanding the real physics through modeling studies, which is quite difficult to describe through classical modeling techniques (Bogatkov and Babadagli 2010; Stalgorova and Babadagli 2012). Thus, one may conclude that a good reservoir characterization study could be sufficient to make an EOR project successful, even if there is no numerical model study properly describing the physics of the process and matched pilot data.

Proper 'technical' design and implementation (continuous monitoring, assessment, and re-engineering the processes)

In most EOR cases, the importance lies with how to do rather than what to do. Often, there may not be many options due to either reservoir compatibility or availability of the injectant (the Weyburn/Midale or Wasson Denver Unit, or Bati Raman CO_2 cases); but, with an initial proper design and re-engineered implementation, together with continuous monitoring and re-evaluation, projects might be successful even if the method may not be suitable theoretically. Cases G1, G2, G4-G9, and S1-C6 in Table 2 fall in that category. More specific examples include the Weyburn (G1 locating injection and production wells properly), Bati Raman (G3, switching from cyclical to continuous injection, starting recycling CO_2 timely), Wasson Denver (G9, changing injection/production patterns, and converting producers to injector continuously), Suplacu de Barcau (A2, changing injection patterns continuously for a better sweep) projects, as well as chemical

projects given in the cases of C1-C5. In summary, if properly designed and managed, EOR can be made economic.

Successful pilot

The role of pilots in the success of EOR applications is highly debatable, as discussed earlier. Considering the time spent and cost involved, the pilots may not be desired as a step in the decision-making process (Hite and Bondor 2004); in fact, simulators do a good job if the physics (mechanics) of the EOR process can be described and reservoir heterogeneity is not a critical issue. Then, the pilot period could be removed or shortened to reduce the incubation period for EOR, as it may take up to several years as indicated in Fig. 8. In special cases, however, pilots can capture certain operational and technical characteristics (or problems) of the process that simulators cannot. In these cases, pilots also collect valuable data as to both the physics and the effect of reservoir geology on said process (e.g. fracture density, orientation, reservoir connectivity, etc.). The Bati Raman (Sahin et al. 2014) and Qarn Alam steam pilots (Macaulay et al. 1995; Al-Shizawi et al. 1997; Shahin et al. 2006; Penney et al. 2007) are good examples for these types of situations; in the former, the pilots of cyclic injection failed due to heterogeneity and continuous injection, without any pilot studying 'random' distribution of the producer and injectors. Through a good engineering design and continuous monitoring, a CO_2 injection project was implemented successfully and economically for more than 30 years. Similarly, the field-scale development plan for the Weyburn/Midale CO_2 injection case relied on 'well-designed' pilot observations and interpretation of the data gained, rather than numerical models of this complicated process in a complicated fractured reservoir (Beliveau 1987). Of which was done without paying attention to economic indicators of the pilot performance.

Pilots might be useful, not for future performance forecasting, but to understand the physics and operational conditions (well design) and injection strategy (well alignments and injection patterns) even if the reservoir heterogeneity is not a critical issue (the physics of the process is uncommon and complicated). The improvement of CSS in the Cold Lake field (Stark 2013) through solvent addition is a typical example for this case.

A similar case is the UTF pilots, which revealed valuable information and insight into the newly proposed SAGD method not possible through numerical, lab-scale experimental, and other computational model studies. Although certain data was gathered for steam/oil ratio type evaluations, the main purpose of the UTF pilot projects was not to evaluate the economic viability of this marginally expensive process. Instead, the ultimate goal was to collect data as to the applicability of SAGD in these types of reservoirs and determine the optimal operational conditions related to injection and well characteristics (Edmunds et al. 1989; Mukherjee et al. 1994; Yee and Stroich 2004).

Expertise (human factor)

Although creativity is an important factor in the design (especially the initial one with limited information about target reservoir), EOR management is a matter of experience and accumulation of knowledge; hence, it relies on the human factor to a great extent. In mid- and small-sized companies (and even NOCs), this could even be more critical as it may need a "champion" to recommend the method and lead the project work, thus driving other people. The success of all steam cases in Table 1 (S1 through S6) as well as the CO_2 (G21) and miscible floods (G4, G5, G6) cases listed in Table 1 can be attributed to the company (or human) "expertise" gained over decades through different projects of the same EOR method.

All (or some) of the above

If lucky enough, one may have many (if not all) of the criteria listed above as positive in Table 1 and go for the EOR method desired. G1, G4, S1, and S4 are examples of this kind (at least 7-8 out of 10 criteria are met) as seen in Table 2; however, this ideal situation may not be possible, practically, all times meaning that one must then evaluate the positive factors to make a decision for an EOR process. What if there is a natural

source of CO_2 or plenty of a "clean" water supply ready for boiling in steam generators, with available and cheap energy sources for boilers, even if many other technical (reservoir suitability or so) conditions are not met, as listed in Table 2? Then, one has to be unbiased and instead of opting for non-EOR development plan, go with an optimistic approach to implement an EOR to extend the lifespan of the field, targeting mid- to long-term total profit even if it may not be a quick gain in the short run. Often, this has been the case as explained above. Through an optimal design and smart engineering exercises, EOR methods could be adapted to the field. In fact, not many options except EOR may exist in many giant to small-sized complex fields (heavy-oil, offshore, unconventionals, etc.) for further development.

Discussion, remarks, and conclusions

After 30 years of efforts in fundamental and applied research in the area of EOR and heavy-oil, I realized that I accumulated more questions than answers. These questions are raised and evaluated in the paper, considering the fact that right questions are needed to reach right answers and propose suitable solutions. Obviously, in such a "philosophical" paper, more questions are asked rather than answers provided. I counted the number of questions raised in this paper and discovered 47. Through these—considerable number of—questions, a philosophical and systematic evaluation was performed by both reasoning and using real field examples as supportive data to the hypotheses put forward. It is believed that this approach will provide new insights into the concept of EOR and implementation of the projects for the next decades.

The main question asked in this paper is something developed after extensive discussions with industry over a handful of decades as to why recovery by EOR processes is lower than expected despite the tremendous research effort devoted. This brought up the following question: Is it only economic restrictions of the projects (simply the oil prices) that make companies refrain from enhanced oil recovery (EOR) applications or are there some technical issues involved in this? If it is the oil prices as a dominating factor, then why have so many EOR applications been successful and sustainable over times with bottomed oil prices?

The supporting data shows that not only economics affect EOR if other conditions are satisfied, as listed in the previous chapter and Table 2. If satisfactory amounts of these conditions are met, EOR projects could be made viable economically. In other words, we can choose EOR as a solution to extend the life of the field. Additionally, apply the methods anytime in a reservoir to improve the short- or long-term gaining.

What should be considered first when starting an EOR project; a technical or economic assessment? It is obvious that the ultimate goal is an economic success (profit), but in regards to EOR, one has to be confident with the technical viability (or success) first (Bondor 1993). If one starts the project development with the search for an economic method and goes back to prove that it works, it might be a risky approach. Initially, almost all cases would present restrictions in terms of the economics of the project—unless there is access to a low-cost injectant (natural CO_2 source around or air injection). Alternatives can be researched if technical success is warranted, but economic constraints exist meaning equal research is required when considering replacing CO_2 with other gas options if CO_2 is scarce. This option may require substantial effort for technical suitability and adapting the alternative injectant to reservoir conditions (even fundamental research specific to field's conditions, i.e. characterization of heterogeneity and its effect on the dynamics of the process) (McGuire et al. 2016).

Based on the criteria listed in Table 2, through the 'philosophical' reasoning approach, and using successful EOR cases worldwide, the following three parameters were found to be the most important factors in running successful EOR applications—regardless the oil prices and risky investment costs to extend the life span of a reservoir and warrant long time profit: (1) proper technical design and implementation of selected EOR method and continuous monitoring being flexible in re-engineering (how to do more than what to do), (2) good reservoir characterization and geological descriptions, and (3) expertise (human factor).

At first sight, reviewing Tables 1 and 2, one may conclude that EOR is an IOC's, NOC's, or big-sized company's responsibility rather than small- and mid-sized company's, a result from the high risk associated with uncertainties, volatile oil prices, knowledge accumulation, expertise needed, and high CAPEX (and even OPEX) investments. Considering the survival conditions in the oil industry one may realize that discontinuity in small-sized companies is a possibility in the long run. This need for survival prevents these types of companies from initiating long-term investments like EOR. Then, prolonged incubation periods (research to field) can be shortened by avoiding long-term pilot efforts or initial studies (lab to simulation), thus relying on well focused "research" studies specifically designed to accelerate decision making. A good design, continuous monitoring, and flexibility in re-engineering are key factors in reaching success for any size of company. All these facts may encourage smaller companies to explore EOR operations as an option to extend the life of the reservoir and make a profit in even short-term situations.

Finally, the following premises can be drawn from this study to be considered in decision making and implementation of EOR projects:

- Existing technologies may not be sufficient, as every EOR process is case-specific and it is difficult to make an analogy to another case. In other words, strongly controlled by reservoir heterogeneity/geology, each EOR project is unique, especially in the case of complex geologies, complicated processes, and unconventionals. More robust experimentation, simulation efforts, or pilot studies are yet to be considered for decision making based on the budget (company size) for such complex cases. Meaning that EOR practices are case dependent, requiring specific research, optimization, expertise, and even trial and error type field demonstrations. In a very recent survey, EOR was listed in ten top priority research and innovation needed areas, being fifth in the list (Alnuaim 2019), despite the tremendous amount of research work published over the last six decades.
- If technical success is proven, any EOR project can be made economical through proper optimization methods—considering the minimal profit that the company can tolerate.
- Discontinuity in research and projects, due to erratic oil prices, has been one of the essential failures preventing continuity of projects, rather than the single factor of sudden drops in oil prices. Research, especially academic, is an exhaustive effort and a very time sensitive part of EOR project development. To minimize its share in the incubation period or EOR applications, it should be well focused and case-specific with well-described targets of investigation and solution-oriented (like SAGD research in the 1990s with suitable involvement of government, companies, research centers, and academia).
- Creative and innovative ideas are critical in developing EOR projects; equally important is experience and expertise gained over time along with accumulated knowledge through similar projects in the past. Hence, the human side of EOR projects could be more important than traditionally thought and more crucial than routine and standard lab-scale and simulation efforts. Often times, "champions" (executers or managers/decision makers assigned to the project) defined as those taking the risk and driving the whole project with their experience, veering away from "book definitions" or "conventional simulation" studies, and continuously monitoring and re-engineering the process are needed. Also needed is patience at every stage of an EOR project as the desired outcome (or data needed) may take longer than expected in this type of "open ended" application (especially the pilot and demonstration stages).
- EOR is a matter of "how to do rather than what to do". EOR methods are well-known and well-defined but cannot be standardized; thus, any EOR method can be done in many different ways, determined by direct (i.e. geology) and indirect (i.e. limited amount of injectant or reservoir accessibility issues) factors. One should focus on "how to do", considering both the unique properties of the reservoir at stake and being creative in designing and implementing an EOR project, rather than limiting the decision and implementation by dogmatically following "book

definitions" which describe "what to do". This paper documented some good examples available in literature for these types of practices like the Bati Raman field (Sahin et al. 2008) and Wasson Denver Unite CO_2 (Bullock et al. 1990; Tanner et al. 1992; Hsu et al. 1997).

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Appendix 1:

Table 1—Selected field case EOR applications, company sizes (B: Big, M: Medium, S: Small sizes, IOC: International Oil Company, NOC: National Oil Company), project start-end dates.

Case #	Field Name (Country)	Company (Size)	Application	Start-End Date	Current Status by IEA*	Reference
			GAS INJECTION			
G1	Midale-Weyburn (Canada)	Cenovus/Apache (B)	CO2 miscible	2000-today	Y	Beliveau 1987; Beliveau et al. 1993; Barnhart and Couthard, 2000
G2	Zama (Canada)	Apache (B)	Acid gas - miscible	1998-2000, 2004-today	Y	Davison et al. 1999; Trivedi at al. 2007
G3	Bati Raman (Turkey) NOC	Turkish Petrolum (NOC)	CO2 immiscible	1986-today	Y	Sahin et al. 2008
G4	Prudhoe Bay (USA)	BP (IOC)	Enriched gas (65%) and CO2 (35%)	1997-1998, 1999-at least 2000	Y	McGuire and Holt 2003; Jhaveri et al. 2014
G5	Magnus (Norway)	BP (IOC)	Enriched gas	2003-at least 2013	N	Zhang et al. 2013; Jhaveri et al. 2014
G6	Ula (Norway)	BP (IOC)	Miscible gas	1997-at least 2013	Y	Zhang et al. 2013; Jhaveri et al. 2014
G7	Swan Hills (Canada)	Amoco Canada-later CNRL (B)	Enriched gas	1982-at least 2002	Y	Griffith and Cyca 1981; Derochie 1987; Edwards 2002
G8	Handil (Indonesia) IOC	Total (IOC)	Lean gas	1995-at least 1998	N	Gunawan and Cale 2001
G9	Wasson Denver Unit (USA)	Shell (IOC)	CO2 miscible	1983-at least 2000	Y	Tanner et al. 1992; Fox et al. 1994; Thai et al. 2000
G10	Cantarell (Mexico)	Pemex (NOC)	N2 injection	2000-today		Sanchez et al. 2005
G11	Mitsue Gilwood (Canada)	Chevron (IOC)	LPG	1985-1995	N	Frimodig et al. 1988
G12	Slaughter Estate Unit (USA)	Amaco (B)	Acid gas	1976-at least 1981	Y	Rowe et al. 1982
G13	Twofreds Unit (USA)	Murphy Oil (M)	CO2	1974-at least 1979	N	Schiltz et al. 1984; Kirkpatrick et al. 1985
G14	North Ward Estes (USA)	Chevron (IOC)	CO2	1989-at least 1995	Y	Ring and Smith 1995; Winzinger et al. 1991
G15	Sacroc Unit Kelly Snyder (USA) IOC	Chevron (IOC)	CO2	1972-at least 1977	Y	Kane 1999
G16	Phegly Unit (USA)	Mobil (IOC)	LPG (a slug) + Natural gas	1964-1966	N	Connally 1972
G17	Jay/LEC (USA)	Exxon (IOC)	Miscible nitrogen (CO2 was not available)	1981-at least 2000	N	Christian et al. 1981; Langston and Shirer 1983; Lawrence et al. 2002
G18	Offshore Abu Dhabi (UAE)	Total (IOC)	Immiscible Gas	1991-at least 2002	Y	Bonnin et al. 2002
G19	East Vacuum Grayburg San Andreas Unit (USA)	Phillips (IOC)	Miscible CO2	1985-at least 1995	Y	Harpole and Hallenbeck 1996
G20	Wizard Lake (Canada)	Texaco (IOC)	LPG	1969-at least 1980	N	Martin and Young 1982
G21	60 CO2 floods (USA)	(S-M-B-IOC)	CO2	1970s-80s-90s-today		Manrique et al. 2007
			STEAM INJECTION			
S1	Duri (Indonesia)	Chevron (IOC)	Steam	1985-today	Y	Fuaadi et al. 1991; Gael et al. 1994; Nath et al. 2007
S2	Cold Lake (Canada)	Imperial Oil (IOC)	Steam	1985-today	N	Stark 2013; Dittaro et al. 2013
S3	Kern River	Getty Oil (later Chevron) (S/IOC)	Steam	1964-at least 1970	Y	Schiltz et al. 1984; Bursell 1975; Greaser and Shore 1980
S3	50 fields (USA)	IOC/B/M/S	Steam	1965-today		Kootungal 2014
S5	Huntington Beach (USA)	Signal Oil (S)	Steam	1964-at least 1970	N	Schiltz et al. 1984
S6	80 fields (USA)	(S-B-M-IOC)	Steam	1965-2003		Hanzlik and Mims 2003
			AIR INJECTION			
A1	Medicine Pole Ills Unit (USA)	Amoco (B)	Air	1985-today	Y	Kumar et al. 1995
A2	Suplacu de Barcau Field (Romania)	OMV Petrom (NOC-M)	Air	1962-today	N	Panait-Patica et al. 2006
A3	South Belridge (USA)	Mobil (IOC)	Air	1964-at least 1986	N	Ramey et al. 1992
A4	West Newport (USA)	Kadane and Sons (S)	Air	1958-at least 1964	N	Schiltz et al. 1984; Koch 1965
A5	Buffalo Red River Units (USA)	Shell (IOC)	Air	1979-at least 1994	Y	Fassihi et al. 1994
A6	Horse Creek (USA)	Total Minatome Corp. (IOC)	Air	1996-at least 1994	N	Watts et al. 1998
A7	Midway Sunset (USA)	Mobil (IOC)	Air	1960-at least 1970	N	Gates and Sklar 1971; Curtis 1989
			CHEMICAL INJECTION			
C1	Pelican Lake (Canada)	CNRL and Cenovus (B)	Polymer	2005-at least 2014	Y	Delamaide et al. 2014
C2	Mooney (Canada)	Blackpearl (S)	ASP, Polymer	2008-at least 2014	Y	Delamaide et al. 2014
C3	Seal (Canada)	Murphy (M)	Polymer	2010-at least 2013	N	Delamaide et al. 2014
C4	Taber South (Canada)	Husky (B)	ASP	2006-at least 2013	Y	Delamaide et al. 2014
C5	Suffield Upper Mannville (Canada)	Cenovus (B)	ASP	2007-at least 2013	Y	Delamaide et al. 2014
C6	Daqing (China)	CNPC (NOC)	Alkali + Surfactant + Polymer	1994-today	Y	Wyatt et al. 2004
C7	Bradford (USA)	Pennzoil (M)	Micellar slug	1971-at least 1976	N	Schiltz et al. 1984; Danielson et al. 1976
C8	Oerrel (Germany)	Deutsche Texaco (M)	Polymer	1975-at least 1981	N	Schiltz et al. 1984; Maitin and Volz 1981
C9	Hankensbuettel (Germany)	Deutsche Texaco (M)	Polymer	1977-at least 1981	N	Schiltz et al. 1984; Maitin and Volz 1981
C10	Glenn Pool (USA)	Gulf later Chevron (IOC)	Surfactant	1982-at least 1992	N	Schiltz et al. 1984; Bae 1995
C11	Bell Creek (USA)	Gary Energy Corp. (S)	Micellar-Polymer	1979-1984	N	Schiltz et al. 1984; Goldburg and Stevens 1981
C12	Big Muddy (USA)	Conoco (IOC)	Surfactant-Polymer	1973-at least 1980	N	Schiltz et al. 1984; Saad et al. 1989
C13	Pownall Ranch (USA)	Hunt Petroleum (S)	Alkali-Surfactant	1996-at least 2002	N	Wyatt et al. 2002
C14	Tanner (USA)	Citation Oil and Gas (S)	Alkali + Surfactant + Polymer (2000–2002)	2000-at least 2006	N	Wyatt et al. 2002; Pitts et al. 2006
C15	Saertu Sand (China)	Daqing Oil Field (NOC)	Alkali + Surfactant + Polymer	1994-at least 1996	N	Wyatt et al. 2002; Shutang et al 1996
C16	Rapdan Pool (Canada)	Canadian Discovery (S)	Polymer	1985-at least 2001	N	Wyatt et al. 2004; Pitts et al.1995; Campbell and Bachman 1987
C17	David pool (Canada)	Dome Petroleum later Amoco (S-B)	Alkaline-Polymer	1987-at least 2001	N	Wyatt et al. 2004; Pitts et al. 2004
C18	North Burbank (USA)	Phillips (IOC)	Micellar-Polymer	1970-at least 1978	Y	Schiltz et al. 1984; Trantham and Moffitt 1982; Bradford et al. 1980
C19	Robinson M-1 (USA)	Marathon (B)	Micellar-Polymer	1977-at least 1979	N	Schiltz et al. 1984
C20	Manvel (USA)	Texaco (IOC)	Micellar-Polymer	1977-at least 1979	N	Schiltz et al. 1984; Hamaker and Frazier 1978; Widmyer and Pindell 1981
C21	Slaughter (USA)	Texaco (IOC)	Surfactant-Polymer	1981-at least 1983	N	Adams and Schievelbein 1987

*: The EOR projects reported as "ongoing" on the IEA website (McGlade et al. 2018) are marked by "Y" in column "Current Status by IEA".

Appendix 2:

Table 2—Reported long-lasting and successful EOR applications and projects.

Factors controlling the success	G1	G2	G3	G4	G5	G6	G7	G8	G9	G10	S1	S2	S3	A1	A2	C1	C2	C3	C4	C5	C6
Field (asset) size*	B	M	M	G	M	M	B	G	B	G	B	G	B	S	M	B	S	S	S	S	G
Company size **	B	B	NOC	IOC	IOC	IOC	B	IOC	IOC	NOC	IOC	IOC	S IOC	B	NOC M	B	S	M	B	B	NOC
Availability of -cheap- EOR agent	Y	Y	Y	N	N	Y	N	N	N	N	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Low oil prices	Y	Y	Y	Y	Y	Y	Y	?	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Low CAPEX/ low OPEX	N/N	N/ N	N/ N	N/N	N/N	N/N	N/N	N/ N	N/N	N/ N	N/N	N/N	N/ N	Y/ Y	Y/ Y	Y/ N	Y/ N	Y/ N	Y/ N	Y/ N	Y/ N
Technical suitability of technology***	+	+	-	+++	+	+	-	+	+	-	+++	++	+++	++	+++	-	-	-	-	-	++
Good understanding of reservoir geology/complexity***	+++	+++	+	+++	+++	+++	++	+++	+++	++	+++	+++	+++	+++	+++	+++	+++	+++	+++	+++	+++
Proper design and implementation***	+++	+++	++	+++	+++	+++	+++	+++	+++	+++	+++	+++	+++	+++	+++	++	++	++	++	++	++
Successful pilot	Y	Y	N	Y	Y	Y	Y	N	Y	N	Y	Y	Y	Y	Y	-	-	-	-	-	-
Expertise (human factor)	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

*: Abbreviations: G: Giant field, B: Big Field, M: Mid-size field, S: Small field

**: IOC: International Oil Companies, NOC: National Oil Company, B: Big (major) company, M: Medium size company, S: Small company (independent).

***: Technical suitability of technology: +: Lightly suitable, ++: Moderately suitable, +++: Strongly suitable, -: not suitable

****: Y: Yes, N: No