Opportunities and Challenges of Polymer Flooding Under Adverse Mobility and Harsh Conditions to Unlock the Potential of Heavy Oil Reservoir in North Kuwait

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Extended abstract

Generally, thermal recovery methods are used to develop shallow, heavy oil reservoirs. However, these methods have technological, economic, and environmental constraints. As per recent developments, synthetic polymers promise more efficient economic oil recovery by improving sweep efficiency and reducing viscous fingering from heavy oil reservoirs under harsh conditions. The South Ratqa Lower Fars (SRQLF) heavy oil (50–2500 cP) reservoir in north Kuwait consists of high permeable (2–10 Darcy) unconsolidated sandstones deposited under fluvial, deltaic, and shallow marine conditions. The reservoir has harsh conditions with 10,000–70,000 ppm salinity, hardness 45,000 ppm, and a strong bottom aquifer. Polymer flooding in this reservoir under harsh conditions is challenging and has the opportunity to unlock its potential. This study discusses the challenges of polymer selection in the laboratory and workflow to assess potential and field implementation by polymer flooding in heavy oil under harsh conditions. This paper also addresses methodology for production strategy by polymer flooding using numerical simulation and economic analysis.

The high reservoir permeability enables stretching the viscosity limit of a selected synthetic polymer using produced water in the laboratory. The selected high molecular weight polymers exhibited a good filterability ratio (≈ 1), good thermal stability (90 days at 70°C), and desired viscosifying power with less adsorption (103–130 g/g rock). For the simulation study, the reservoir was divided into six geologically similar areas based on reservoir characteristics and oil viscosity. Then a high-resolution geological model is constructed of a high-potential area to assess polymer-flooding performance over water flooding and primary production. The simulation study was carried out to select the best injection pattern type, well completion strategy, injection and production rate, in- situ mobility ratio, polymer slug size requirement, incremental oil recovery, and economics for polymer flooding.

The results of the study show implementing polymer flooding in the early stages of field development gives better economic benefits. An inverted 7-spot injection pattern with 80-meter well spacing provides better results in terms of techno-economic oil recovery in polymer flooding. The selected polymer with a viscosity of 56 cp in the in-situ condition achieved a mobility ratio in the range of 1.2-2.7. The selected optimum well spacing shows poor primary recovery (5% OOIP) and 20% additional oil recovery with water flooding due to fingering. The polymer flooding using produced water can give an additional 12–15% OOIP oil recovery over a water flood. The workflow adopted in this paper can allow mature fields to economically produce more oil and provide guidance to engineers screening heavy oil reservoirs for potential application of polymer flood.

Keywords: Polymer Flooding, Harsh environment, Heavy Oil Reservoir, adverse mobility ratio

1. Introduction

Thermal recovery techniques are primarily employed to enhance the extraction of shallow, heavy oil reservoirs. The Large-Scale Steam Flood Pilot project in the South Ratqa Field, located in North Kuwait, represents a pioneering initiative for the Kuwait Oil Company (KOC) and marks a significant advancement in the North Kuwait Heavy Oil Development program. This pilot initiative is essential for the development strategies of North Kuwait Heavy Oil, as it facilitates a detailed assessment of the Lower Fars Heavy Oil reservoir through closely spaced evaluations. Additionally, it will analyze the effects of the chosen recovery method on the operations and economic viability of the South Ratqa field. The production and operations data management system oversees the phases of steam injection, soaking, and production by means of data collection, quality control validation, and production back allocation, along with shortfall analysis for both planned and unplanned downtimes. Production and reservoir engineers often utilize allocated volumes to estimate current production levels from wells, relying on frequent well testing data or theoretical calculations based on well and reservoir characteristics. Nonetheless, these approaches face technological, economic, and environmental limitations. Furthermore, the steam flooding is currently confined to a limited area, despite the vast potential of the reservoir. Consequently, various technologies have been investigated to explore the potential of North Kuwait heavy oil fields (AlAbbasi et al., 2019). An Enhanced Oil Recovery (EOR) screening was conducted for the heavy oil reservoir in North Kuwait (Al- Mayan et al., 2016). The initial screening indicated that polymer flooding could be a viable option for this heavy oil reservoir utilizing produced water. Additionally, several chemical EOR methods were designed and tested in the heavy oil reservoirs of North Kuwait (Al-Murayri et al., 2018; Al-Murayri et al., 2016; Zhu et al., 2021). However, selecting a heavy molecular weight polymer suitable for the reservoir's harsh conditions and achieving the necessary viscosity under in-situ conditions remains a significant challenge. Recent advancements indicate that synthetic polymers offer the potential for more effective economic oil recovery by enhancing sweep efficiency and minimizing viscous fingering in heavy oil reservoirs subjected to severe conditions. Consequently, while polymer flooding in such reservoirs presents significant challenges, it also holds the promise of realizing their full potential. This article examines the difficulties associated with polymer flooding in heavy oil under extreme conditions, focusing on the following objectives:

- Conducted an analysis of the rock and fluid characteristics of the South Ratqa (SRQ) Heavy Oil Reservoir.
- Addressed the difficulties in choosing appropriate polymers to achieve the desired viscosity within an in- situ reservoir, utilizing produced water as the injection medium.
- Explored both the opportunities and challenges associated with enhancing the potential of heavy oil reservoirs through polymer flooding.
- Developed a tailored sector simulation model for specific purposes.
- Determined the optimal injection pattern and well spacing.
- Forecasted oil recovery outcomes under scenarios of no field activity, water flooding, and polymer flooding.
- Evaluated the scenarios of no field activity, water flooding, and polymer flooding.
- Conducted a comparative analysis of the mobility ratios between polymer floods and water floods.
- Performed a high-level economic assessment of polymer flooding.

2. South Ratqa Lower Fars (SRQLF) Heavy Oil Reservoir

The SRQLF reservoir is a North Kuwait heavy oil reservoir of Lower Fars formation (Middle Miocene age) with Monocline / Small Anticlines structure along plunging from North-East to North-West as shown in Figure 1. The Lower Fars Formation is part of a wedge comprising fluvial, lacustrine, and paralic deposits that formed following the emergence of the Arabian Peninsula during the middle Eocene epoch, alongside the tectonic uplift and tilting resulting from the initial collision between the Arabian and Eurasian plates in the Oligocene epoch. In the context of Kuwait, the Lower Fars Formation lies conformably above the lower Miocene Ghar Formation and transitions into the upper Miocene to Pleistocene Dibdiba Formation. Consequently, this formation consists of a mixture of unconsolidated sandstones and shales that were deposited in fluvial, deltaic, shallow marine and terrestrial environments. Despite a consistent regional stratigraphic framework, the intervals within the Lower Fars Formation exhibit considerable lateral heterogeneity in petro-physical properties, attributed to variations in sand texture, localized pore-filling cement precipitation, and differences in the thickness and occurrence of discontinuous interbedded shales. Within this formation, post-depositional calcite and dolomite cementation along baffling layers significantly influence flow zones. The oil trapping mechanism of this reservoir is characterized as a combination of stratigraphic and structural elements. The reservoir is sealed by Cap Shale and Mid Shale. It is characterized as a very shallow, low-temperature reservoir with high permeability and heavy oil exhibiting significant viscosity. The petro-physical properties of the reservoir are detailed in Table 1 (Alali et al., 2023). The reservoir is categorized into zones F0, F1A, F1B, F2A, and F2B based on petro-physical characteristics and geological descriptions, as depicted in the typical well log shown in Figure 2.

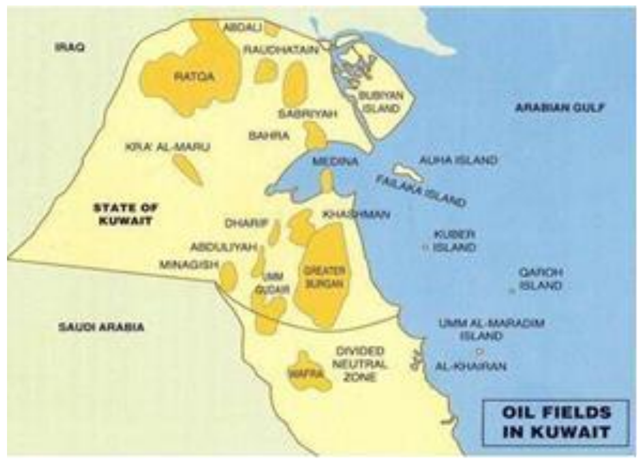

Figure 1: RATQA heavy oil field location

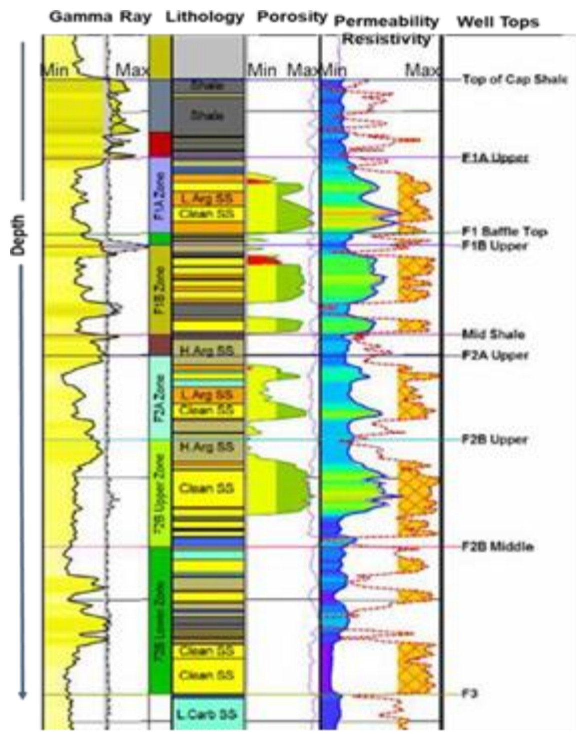

Figure 2: Typical log showing petro-physical properties variation and zone classification

Table 1: Average rock and fluid properties of SRQLF reservoir

Parameters	Value/ Description
Lithology	Unconsolidated sandstone
Wettability	Intermediate-wet
Depth (ft)	350 to 1,200
Net thickness (ft)	10 to 55
Temperature (°F)	~90
Permeability (D)	2 to 10
Oil composition	High C5-C12
Oil density (°API)	10 to 18
Oil viscosity (cp)	50 to 2,500
Formation water hardness (ppm)	~45000
Formation water salinity (ppm)	~10,000 to 70,000

3. Methodology

The initial step involves a comprehensive review of existing literature concerning polymer flooding in heavy oil reservoirs. Following this, the challenges associated with the selection of appropriate polymer types are identified, leading to a laboratory study aimed at determining suitable polymers. Then, we discussed the challenge of applying polymer flooding in the harsh conditions of the subject heavy oil reservoir. The fit-for-purpose reservoir simulation model was extracted from a full-field history-matched model. The reservoir simulation was carried out to select optimum well spacing and injection pattern. Additionally, simulations were performed for scenarios involving no field activity (NFA), water flooding, and polymer flooding. The incremental oil recovery and performance of polymer flooding in the F1A and F1B zones were subsequently assessed. A comparison of injectivity and mobility ratios between polymer flooding and water flooding was also conducted. Finally, an analysis of the results pertaining to the performance of polymer flooding was executed. The typical methodology is illustrated in the accompanying block diagram (Figure 3).

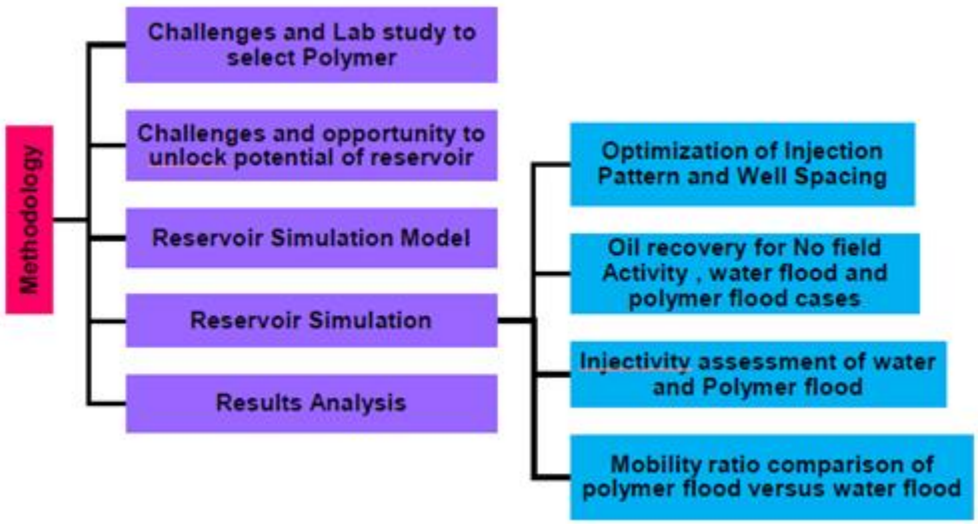

Figure 3: Methodology Polymer Flooding under Adverse Mobility and Harsh Conditions to Unlock the Potential of Heavy Oil Reservoir

4. Laboratory Study and Challenges to Select Suitable Polymer

The reservoir high oil viscosity ranging from 100 to 2500 centipoise, with harsh environment of formation water characterized by salinity levels between 10,000 and 70,000 parts per million and hardness of 45,000 parts per million, as detailed in Table 1. The source of injected water is identified as harsh produced water, containing 4,500 parts per million total dissolved solids, which may be heated to temperatures reaching 70 °C, as illustrated in Table 2. Consequently, identifying appropriate polymers capable of withstanding these severe conditions presents a significant challenge.

Table 2: Produced water composition as injected source

Ion	ppm
Ca++	2670
Mg++	1240
Ba++	1.2
Sr++	64
Fe++	0
K+	1400
Na+	11600
HCO3-	80
Cl-	26766.89
SO4=	1000
TDS	44822.09

Therefore, three polymers of high molecular weight (>15 MDa) were explored in the laboratory using simulated produced water as specified below:

- SNF Polymer: Polymer 1
- SNF Polymer: Polymer 2
- ZL Polymer: Polymer 3
- SNF Polymer: Polymer 4

The three high-molecular-weight polymers present in produced water (with a total dissolved solids hardness of 45,000 ppm) demonstrated excellent filterability, achieving a filtration ratio of 1, and exhibited substantial thermal stability, maintaining 80% or higher after 90 days at an elevated temperature of 70 °C. Notably, SNF polymer 1 displayed superior thermal stability compared to polymer 2, as illustrated in Figure 4. The desired viscosity for the injected polymer solution was targeted within the range of 30-40 cp, based on the injectivity assumptions for the SRQLF reservoir. These polymers possess the requisite viscosifying capability, allowing for significant viscosity levels with minimal dosage to achieve target viscosities of 24 cp at 2200 ppm, 56 cp at 3200 ppm, and 33 cp at 3300 ppm at a shear rate of 10 sec-1 at 32 °C for polymers 1, 2, and 3, respectively (refer to Figures 5 and 6). All three polymers demonstrated effective transport in core fluid, showing no signs of plugging, permeability reduction, or significant retardation when interacting with produced water containing 45,000 ppm TDS hardness (see Figure 7), with an acceptable lower adoption range of 103-130 g/g rock. Several core floods were conducted to analyze the desaturation effects of the polymer flood and the reduction of the mobility ratio under reservoir conditions. The core flood results clearly indicated a decrease in the mobility ratio and a reduction in initial oil saturation from 90% to 42%. The final initial oil and residual water saturations were recorded at 90% and 10%, respectively. The resistance factor remained within 20% of the viscosity ratio between the polymer and water (notably, the pressure drops measured during the "Brine flood" in Section 3 for Polymer 3 were abnormally low, leading to uncertain results). The inaccessible pore volume was measured at 0.08 (8%) in the laboratory and subsequently incorporated into the simulator.

Core flood using SNF polymer 1: The pressure drop for polymer flood 1 is shown in plot 1 of Figure 7. Pressure drop for polymer flood 1 reached steady state after ~ 3.4 pore volumes (fairly stable after this point, e.g. ≤5% change in pressure over one pore volume). Pressure drop showed no evidence of face plugging or filtering out for the polymer flood. This measurement has some degree of uncertainty due to at least a couple significant reasons. 1) The flood is not viscously stable, and polymer is fingering through the core likely not contacting the entire reservoir core and lowering the apparent sweep. 2) The second polymer flood appeared to have a different, higher adsorption clouding any IPV associated with the polymer. If this is true with a high IPV, the value for retention could be significantly higher.

Core flood using SNF polymer 2: Pressure drop for the second polymer flood is shown in plot 2 of Figure 7. Pressure drop for the polymer flood reached steady state before one pore volume and was fairly stable after this point, e.g.
≤5% change in pressure over one pore volume. Pressure drop showed no evidence of face plugging or filtering out for the polymer flood. The produced effluent viscosities were decreased to about 5% of their injected value. This minor change in viscosity is likely due to change in water composition from mineral dissolution or cation exchange or both. This has been observed in previous corefloods with this core material.

Core flood using ZL polymer 3: Pressure drop for the this polymer flood is shown in plot 3 of Figure 7. The resistance factor was within 20% of the viscosity ratio of polymer to water, except for section 3 that is about 47% (“Brine flood’’, measured pressure drops from section 3 are abnormally low and results are uncertain). This polymer shows good transport in coreflood. Its viscosity is robust, as was expected given its monomer composition. Its high molecular weight should cause no well damage when injected into the loosely consolidated sand.

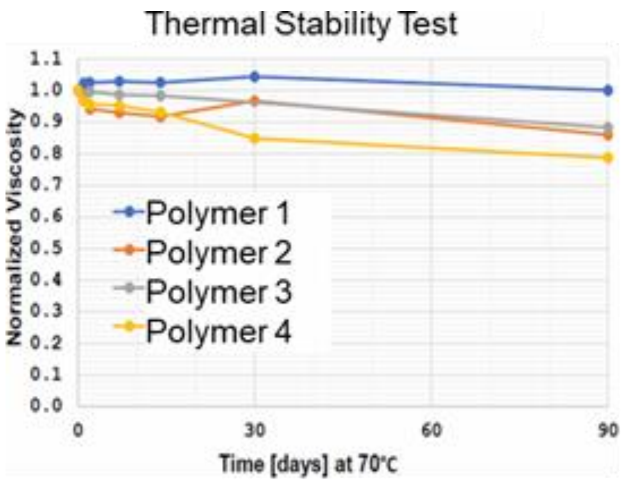

Figure 4: Thermal stability results at shear rate of 7.3 1/s

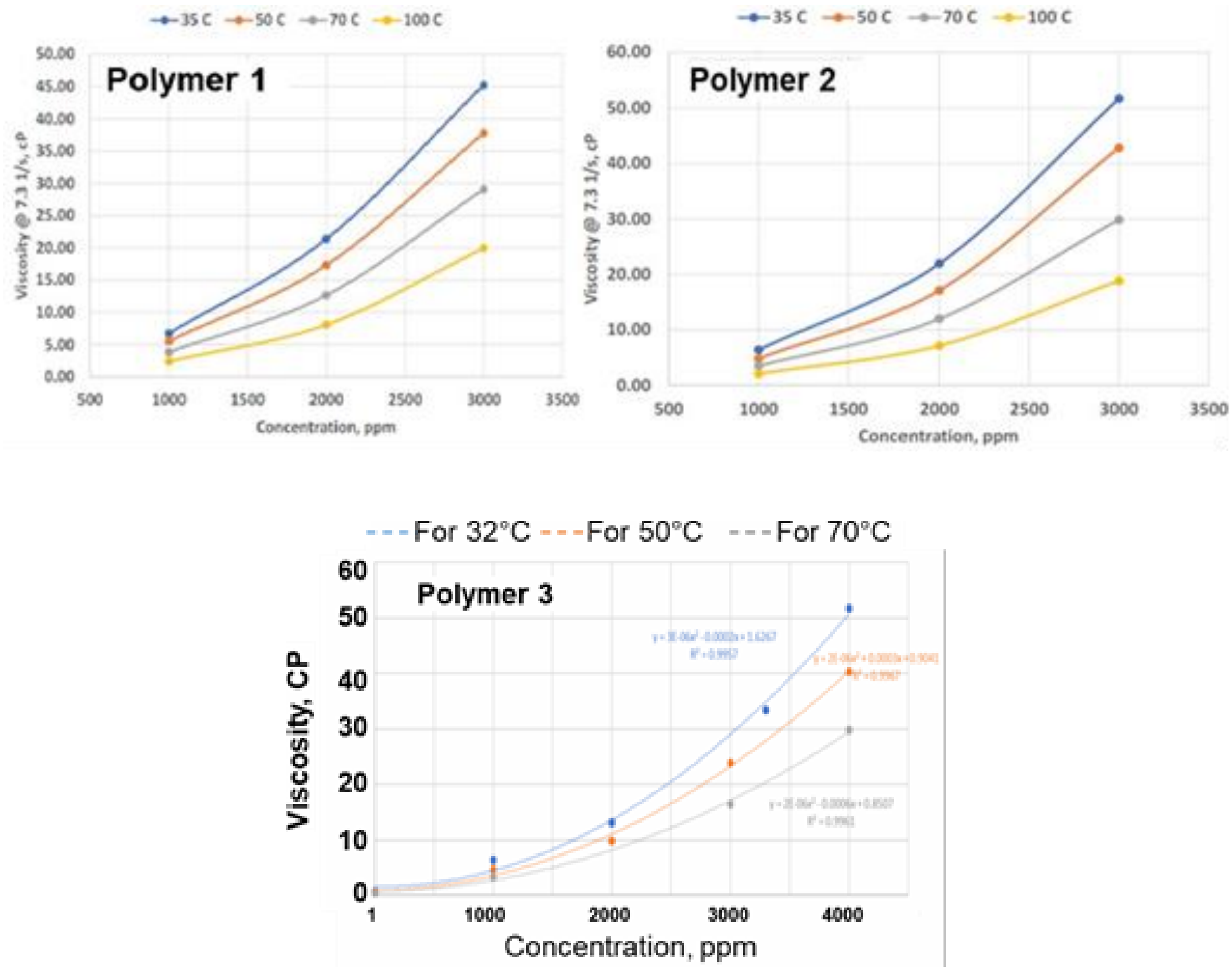

Figure 5: Viscosifying power of polymers at shear rate of 7.3 1/s and temperatures of 35, 50, 75 & 100°C.

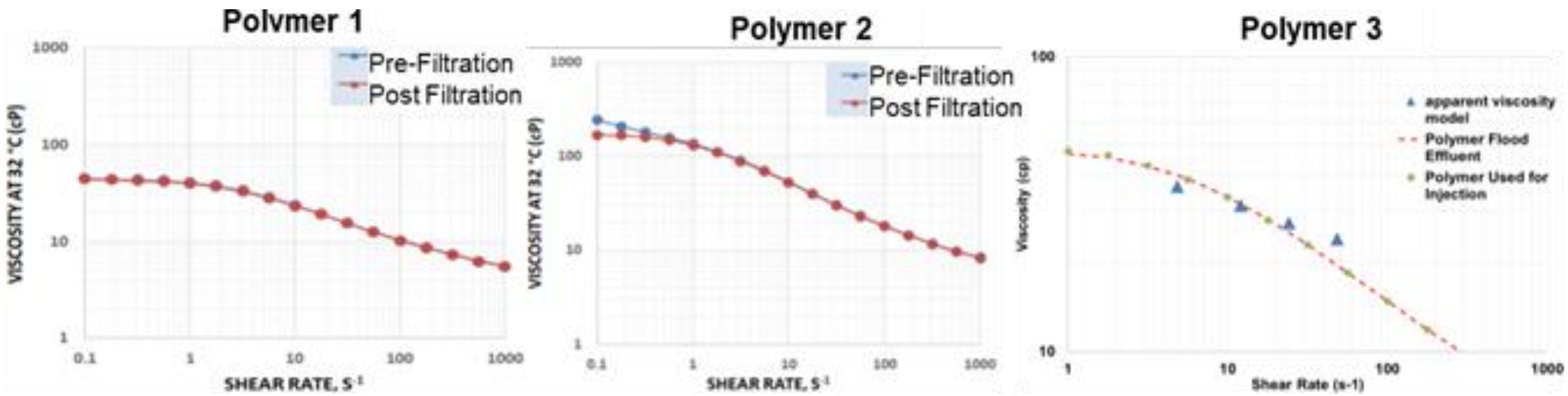

Figure 6: The viscosity relationship with shear rate of the selected polymers

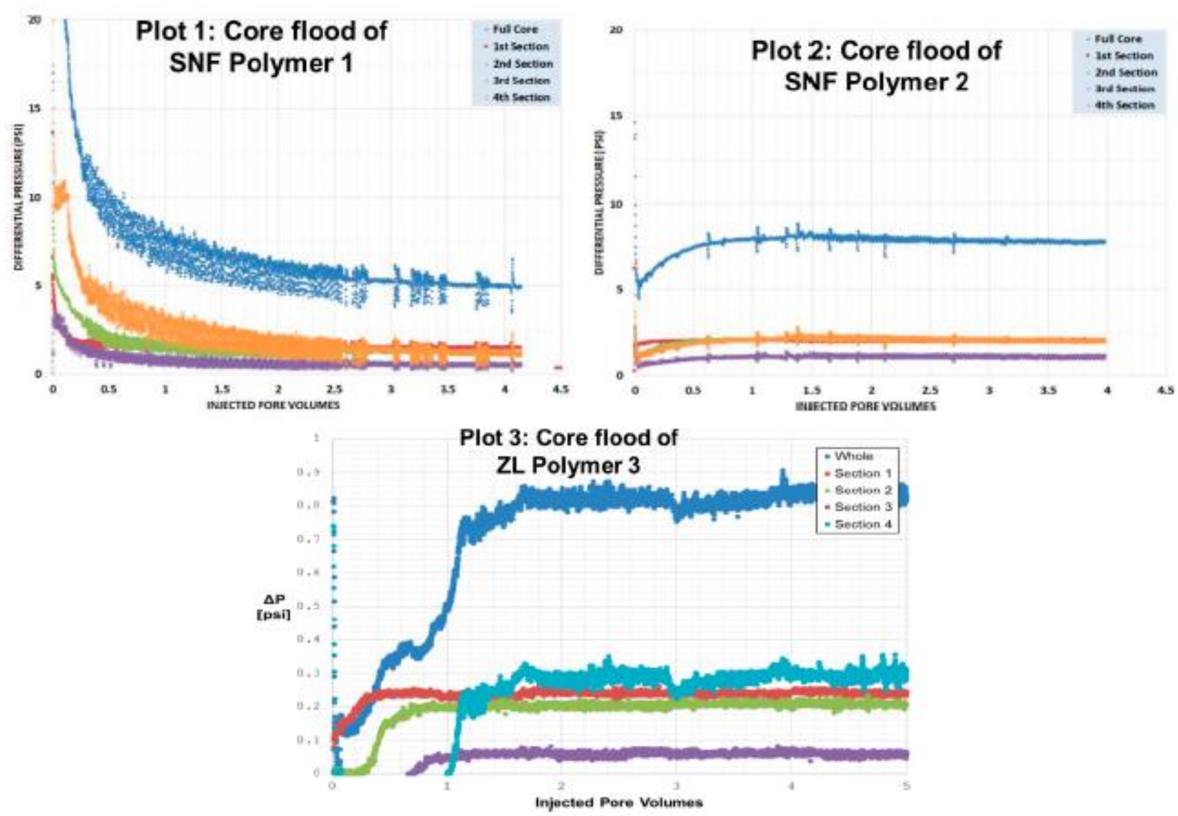

Figure 7: Polymers transportation in the core flooding using cores of the subject reservoirs

5. Opportunity and Challenges to unlock the potential of heavy oil reservoir

The Lower Fars Formation of the subject reservoir displays a distinct and extensive internal stratigraphy. This stratigraphy indicates a history of widespread fluvial to nearshore sedimentation, interspersed with brief periods of shallow marine transgressions. The reservoir comprises F1 and F2 sands, which are predominantly friable to poorly consolidated, moderately to well-sorted, and medium- to coarse-grained, with occasional pebbly textures and rare fine grains, along with relatively common thin shale interlayers. The sands generally show varying degrees of cross-bedding. Locally, there is the presence of patchy carbonate and gypsum cement within the sands. Moving basin ward (to the north and northeast), the sand bodies transition into shale and siltstone, with sporadic thin beds of fossiliferous limestone (Alsharhan and Narin, 1997). Several parameters are critical for analyzing and understanding the challenges associated with heavy oil reservoirs during polymer flooding (Al-Marta, et al., 2017; Bassam, et al., 2019), which will be elaborated upon in the following discussion.

The oil is mainly contained in F1A and F1B zones, while very limited oil is present in the north and south- west areas in the F2A and F2B zones of the subject heavy oil reservoir, as illustrated in Figure 8. Understanding the viscosity of the oil is crucial for addressing the challenges related to the favorable mobility ratio or its reduction through polymer flooding. The viscosity of the oil in this reservoir ranges from lower values in the north to higher values in the south, with the oil in the F1A zone being less viscous than that in the F1B zone. Specifically, the oil viscosity in the F1A zone has a mean of 739 cp and a range of 50-2500 cp, while in the F1B zone, the mean is 1162 cp with a range of 50-2500 cp. In contrast, the sector 3 zone exhibits an oil viscosity range of 20-400 cp in the F1A zone and 900-1200 cp in the F1B zone, as depicted in Figures 9 and 10. Additionally, the salinity of the formation water in the reservoir varies from 10,000 to 70,000 ppm, extending from the north to the southwest, as shown in Figure 11. The formation water has a hardness of 45,000 ppm, a tilted oil-water contact, and a robust bottom aquifer. Notably, the F1A zone exhibits lower formation water salinity compared to the F1B zone. Seismic lines reveal faults and various mapable horizons within the reservoir. The reservoir demonstrates good porosity, ranging from 13% to 22%, and exhibits permeability values between 300 md and 500 md (with very clean sand having permeability measured in Darcy). The connate water saturation ranges from 0.06 to 0.15. Furthermore, laboratory studies indicate that the average residual oil saturation following a water flood, referred to as residual oil saturation (Sorw), falls between 0.25 and 0.35.

The reservoir is categorized into six distinct sector regions (SM1 to SM6) according to their petro-physical characteristics. The volume of oil in place has been observed to decrease in the following order: SM1, SM3, SM2, SM6, SM5, and SM4. Primary production has encountered significant challenges due to limitations in pressure. In the South Ratqa Field, several pilot wells were drilled to conduct thermal production testing. Currently, the South Ratqa Thermal steam flood process, specifically cyclic steam stimulation (CSS), has been established in the North Phase 1 Area of the SM1 sector, which is characterized by the highest quality sand and the greatest original oil in place (OOIP). The existing thermal production techniques are designed to address an oil viscosity range of 100 to 2500 cp. Consequently, there are numerous challenges associated with polymer flooding, including high oil viscosity and its fluctuations. The sector with the next best quality and higher OOIP has been selected for the implementation of polymer flooding.

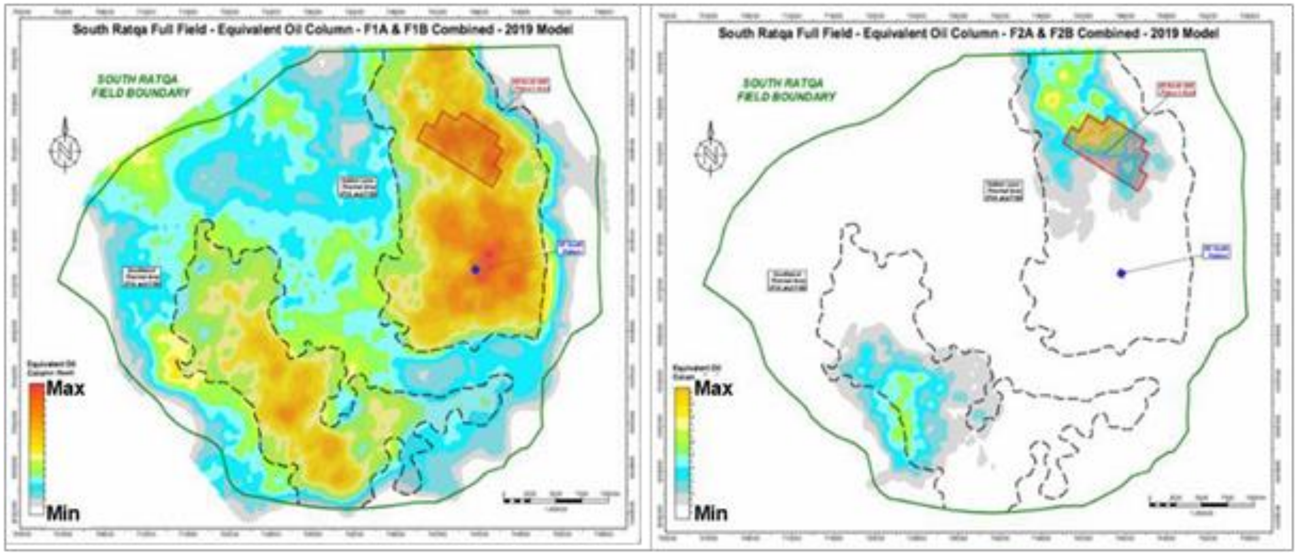

Figure 8: Maps representing areal oil variation (a) Combined oil column thickness of F1A and F1B (b) Combined oil column thickness of F2A and F2B zones

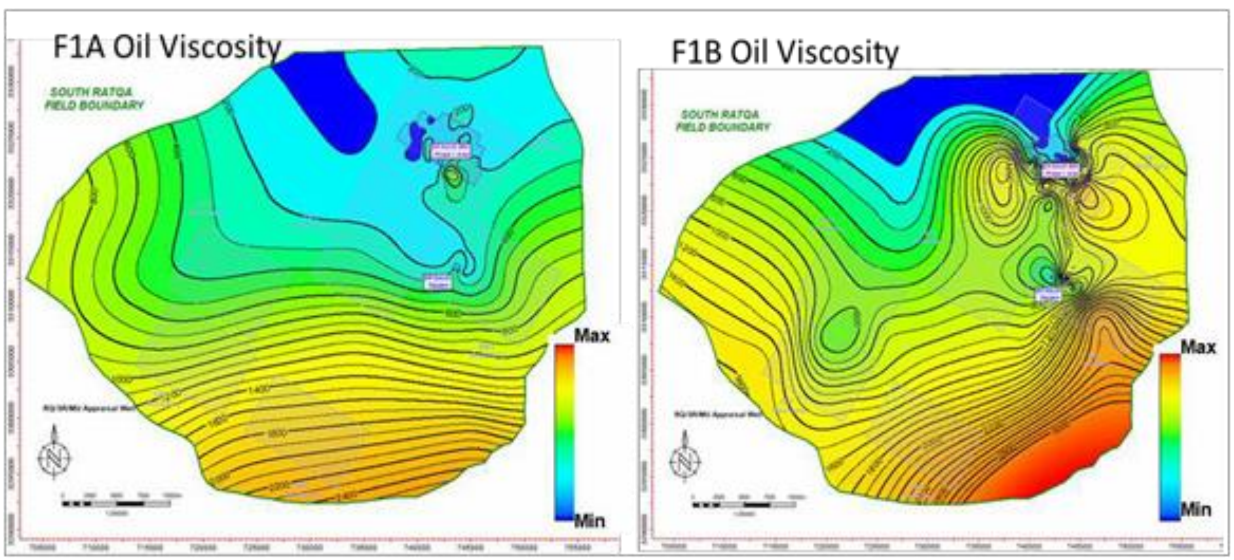

Figure 9: Maps representing areal oil variation (a) Combined oil column thickness of F1A and F1B (b) Combined oil column thickness of F2A and F2B zones

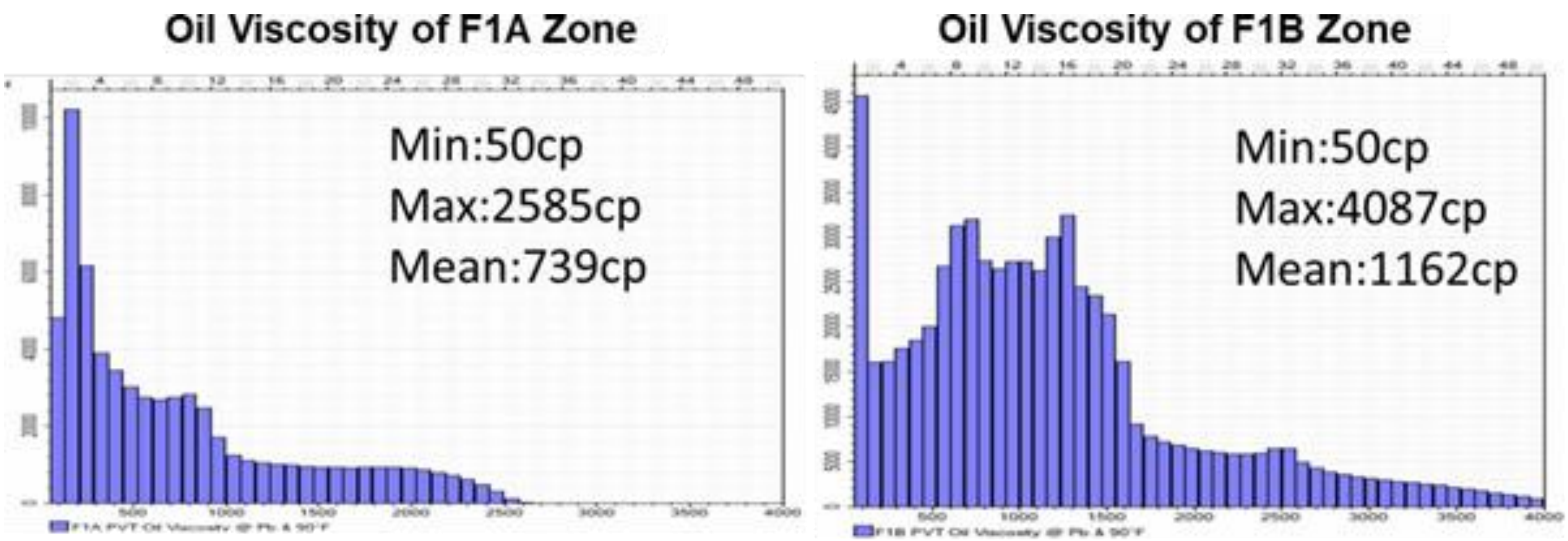

Figure 10: Histogram of oil viscosity in F1A and F1B zones

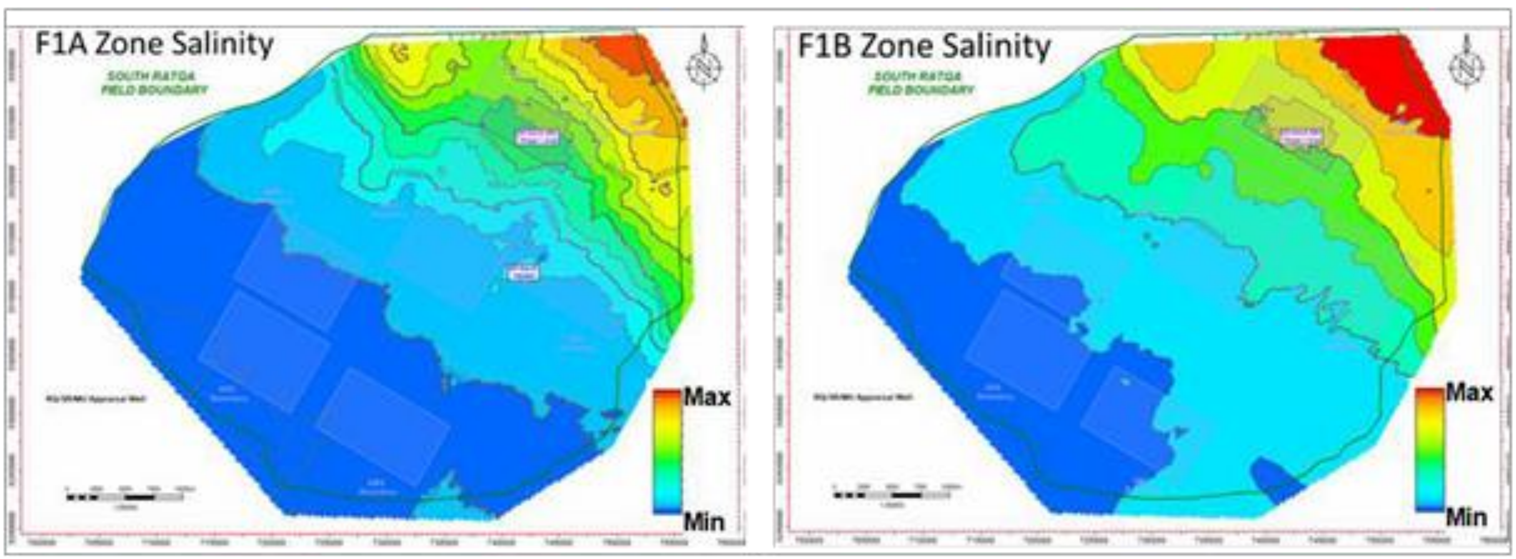

Figure 11: Typical log showing formation water salinity variation

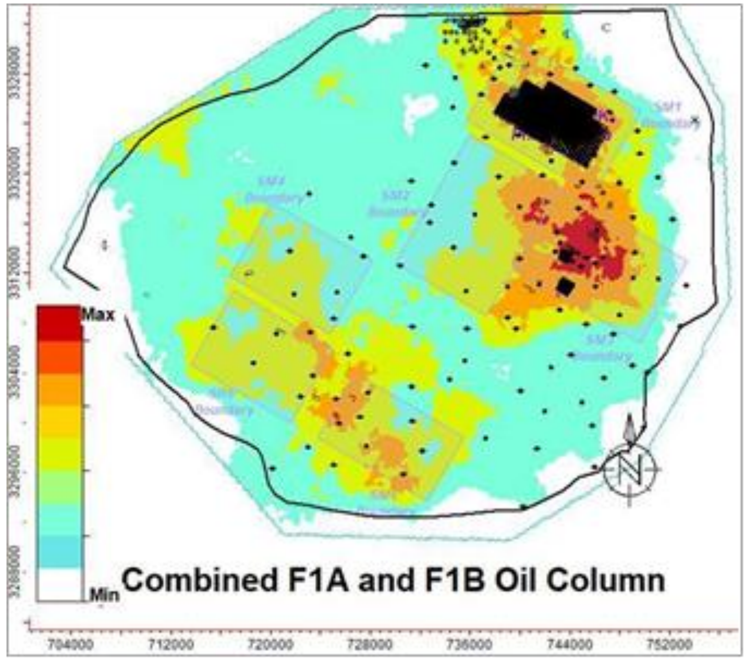

Figure 12: Six sector location in SRQLF reservoir

6. Reservoir Simulation Model

Sectors SM1 and SM3 exhibit the highest Original Oil In Place (OOIP) and remaining oil reserves within the reservoir. The SM1 sector, located on the northern side, has already been developed and is currently utilizing Thermal methods, including Cyclic Steam Stimulation (CSS) and steam flooding for production. Following this, Sector SM3 possesses the next highest OOIP and holds potential for future cold production. The sector model extracted from the history matched full filed model in the area of SM3 sector to assess the performance of polymer flooding, as illustrated in Figure 13. The vertical profiles of permeability and porosity for the sector model are depicted in Figure 14. The selected Sector Model represent good porosity (mean porosity: 28.6%) as well as multi-Darcy rock (mean permeability: ~7Dracy as represented by histogram in Figure 15. The vertical permeability profile reveals that certain layers within the F1A Zone exhibit elevated permeability levels, a trend that is also observed in the F1B Zone. Consequently, the injection profile is expected to be non-uniform due to variations in permeability. Additionally, the injectivity is influenced by the viscosity of the heavy oil present.

Subsequently, a local grid refinement was performed to optimize the polymer flooding process, as demonstrated in Figure 13.

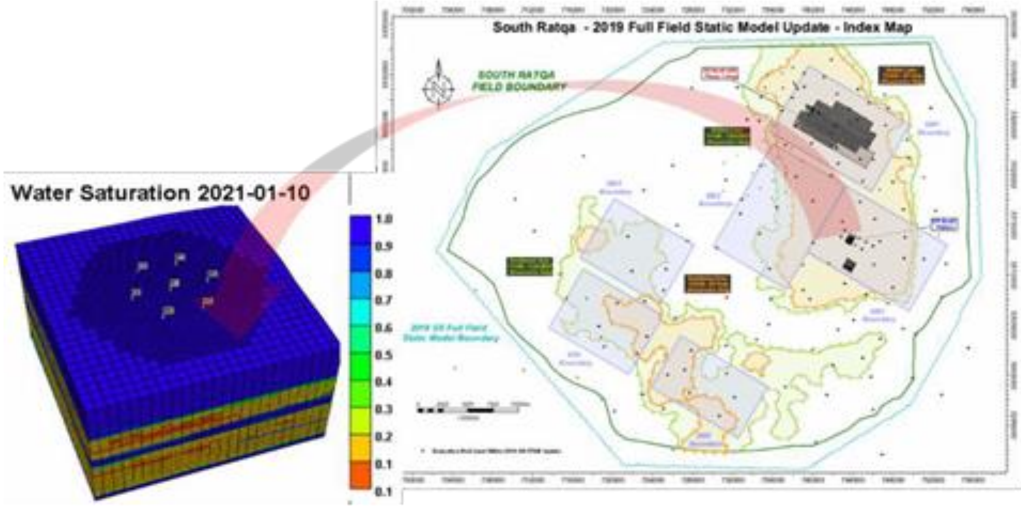

Figure 13: Sector Model

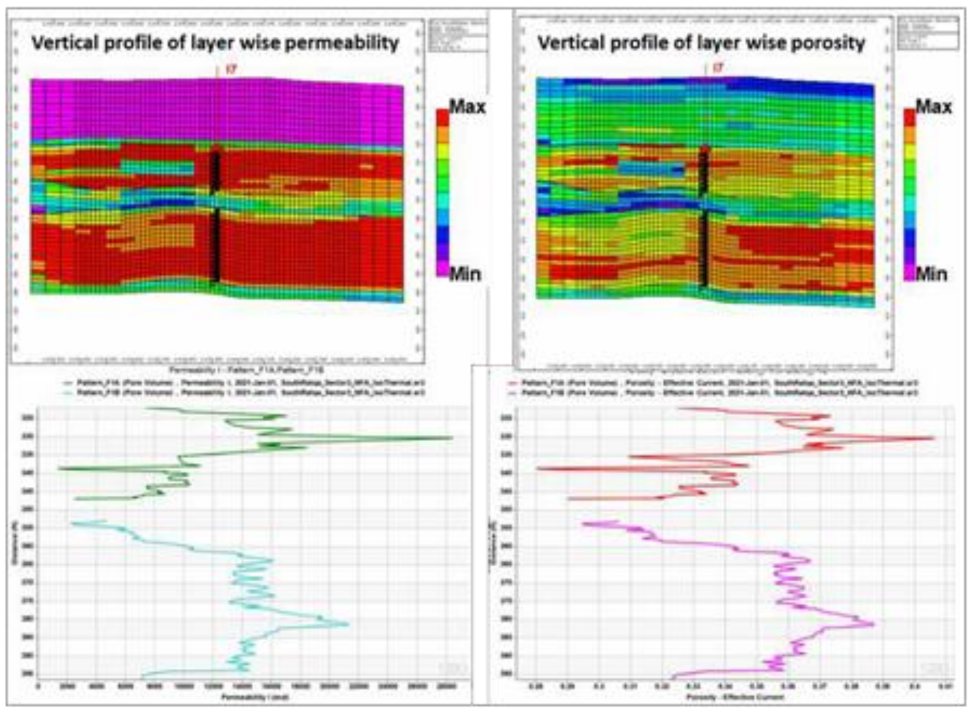

Figure 14: Vertical profile of permeability and porosity histogram of Sector Model

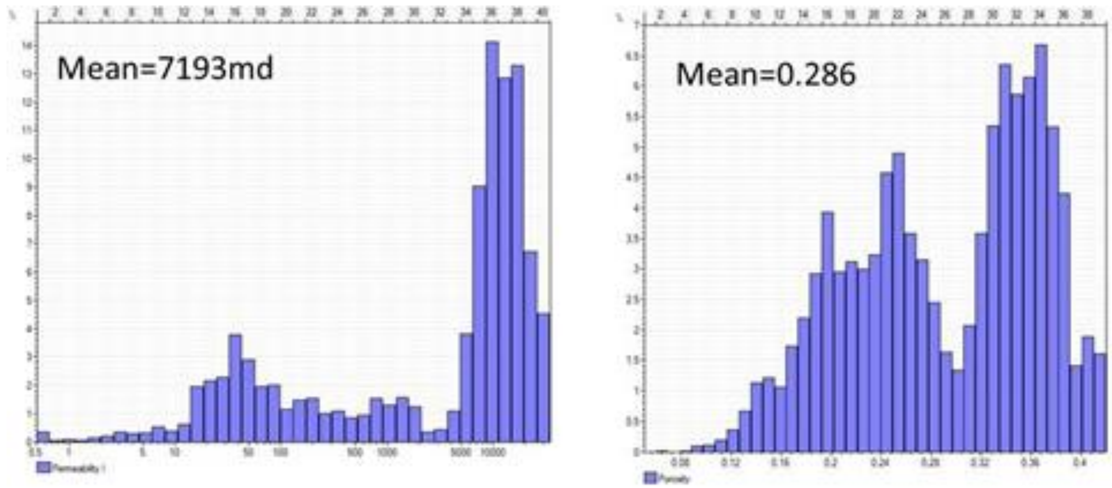

Figure 15: Permeability and porosity histogram of Sector Model

7. Result and Discussion

7.1 Injection Pattern and Well Spacing Optimization

Simulations were conducted employing various injection patterns and well spacing configurations, including inverted 5-spot, 7-spot, and 9-spot, as illustrated in Figure 16. The results indicate that the inverted 9-spot and inverted 7-spot patterns yield superior oil recovery during water flooding, as demonstrated in the oil recovery plot of the water flood process (Figure 17). The both inverted 7-spot and 9-spot injection pattern shows approximately similar oil recovery (Figure 17). Therefore, inverted 7-spot injection pattern was consider due to lower number of wells requirement and subsequently utilized to understand optimum well spacing in the polymer flooding process. The evaluation of polymer flooding involved well spacing ranging from 80m to 140m, utilizing the inverted 7-spot injection pattern. The findings reveal that the inverted 7-spot injection pattern with 80m well spacing achieved the most favorable outcomes in terms of oil recovery, as depicted in the oil recovery plot of polymer flood process (Figure 17). Thus, the inverted 7-spot injection pattern with 80m well spacing was identified as the optimal design for both water flooding and polymer flooding.

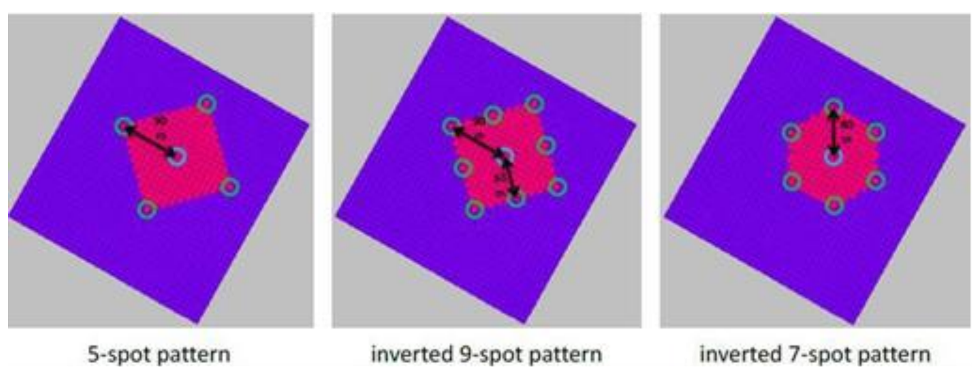

Figure 16: Injection pattern consider in optimization

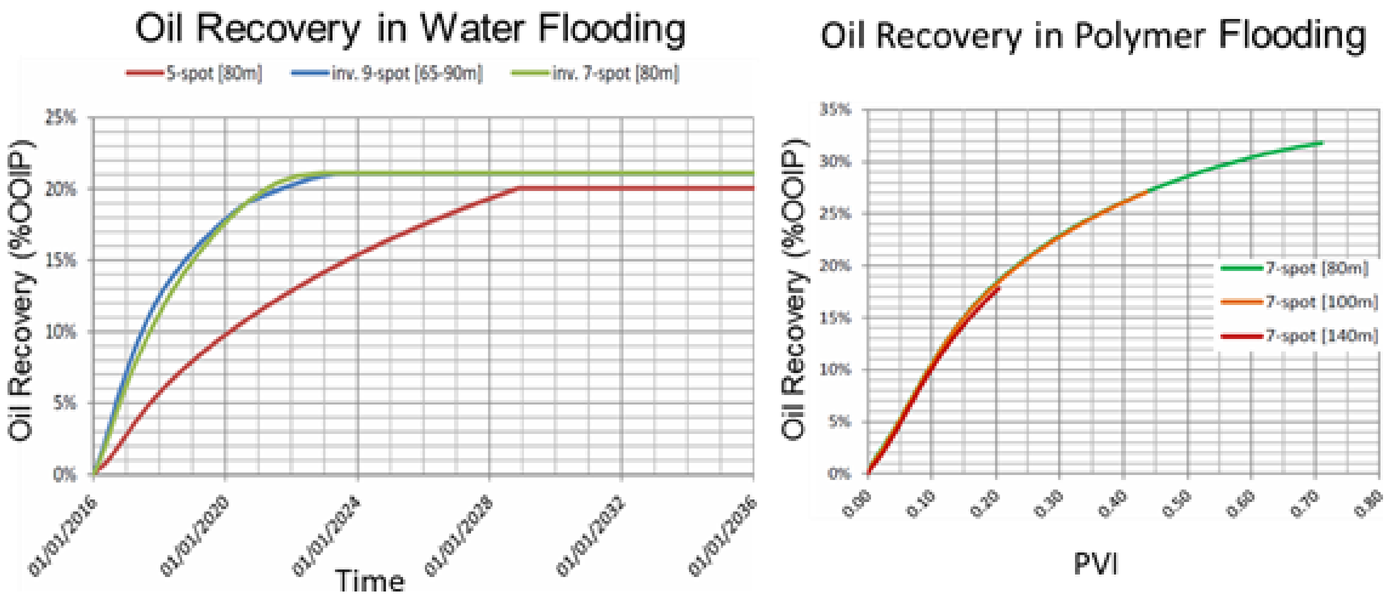

Figure 17: Water and polymer floods performance in different type of injection pattern and well spacing

7.2 Polymer flooding performance over no field activity and water flooding cases

The reservoir simulations were conducted utilizing an optimal injection pattern characterized by an inverted 7- spot configuration and a well spacing of 80 meters. The simulation runs were executed under conditions of no field activity (NFA), encompassing scenarios of natural flooding, water flooding, and polymer flooding. In the polymer flooding scenario, all three types of polymers derived from laboratory outcomes were used in simulation.

The results of the simulations were analyzed for both the F1A and F1B zones, as well as for the three selected polymers. The findings indicate that the F1A zone exhibited a higher degree of desaturation and oil recovery factor in comparison to the F1B zone, primarily attributed to differences in oil viscosity. During the primary depletion phase (NFA case), the oil recovery factor, expressed as a percentage of the original oil in place (% OOIP), was notably low in this heavy oil reservoir, achieved as 10% for the F1A zone and 2% for the F1B zone. The secondary depletion phase i.e., water flooding, resulted in oil recoveries of 32% and 14% for the F1A and F1B zones, respectively, as illustrated in Figure 18. The incremental oil recovery achieved through polymer flooding with the three selected polymers ranged from ~20-24% for the F1A zone and reached ~22-25% for the F1B zone, as depicted in Figure 18. SNF Polymer 2 exhibited a quicker oil acceleration or oil desaturation compared to Polymers 1 and 3. In addition, the Polymer 2 also required less PVI to achieve a similar recovery level when compared to Polymers 1 and 3, as represented in Figures 18 and 19. The both combines F1A and F1B zones shows incremental oil recovery (% OOIP) primary depletion, water flooding and polymer flooding cases as ~ 6%, 21% and 21-25%, respectively (Figure 20).

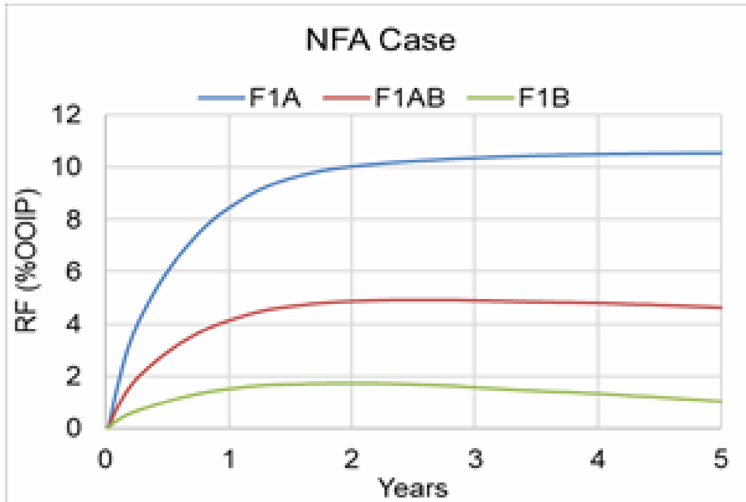

Figure 18: Oil recovery in primary depletion (NFA) for F1A zone, F1B zone and both zone (F1AB).

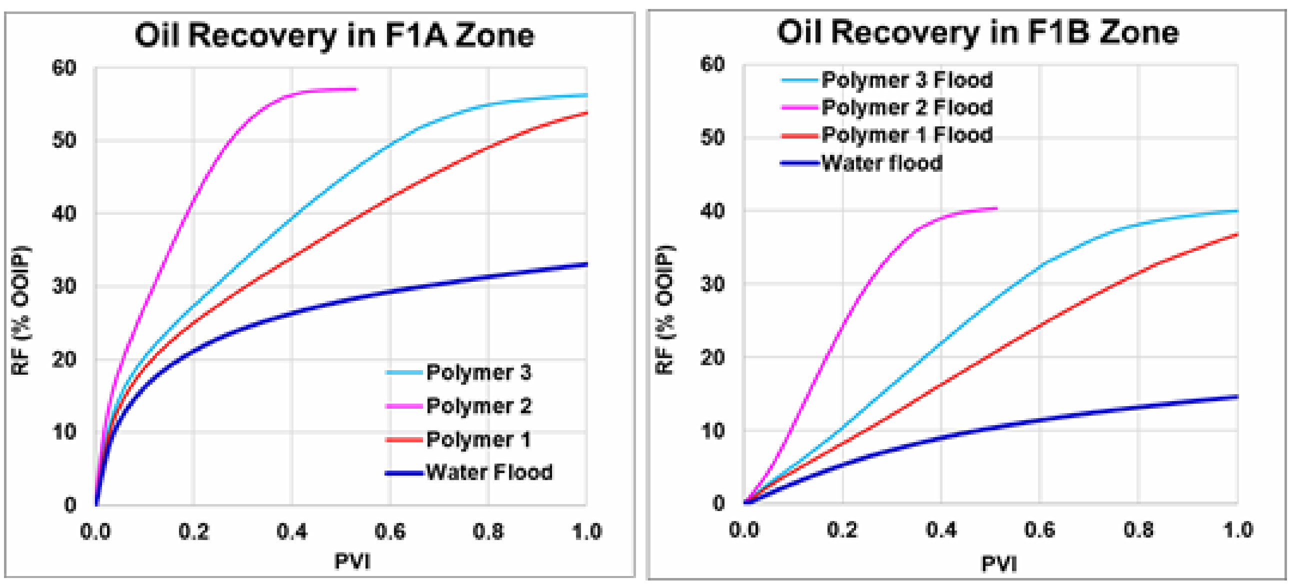

Figure 18: Oil recovery in water and polymer flood cases for F1A and F1B zones.

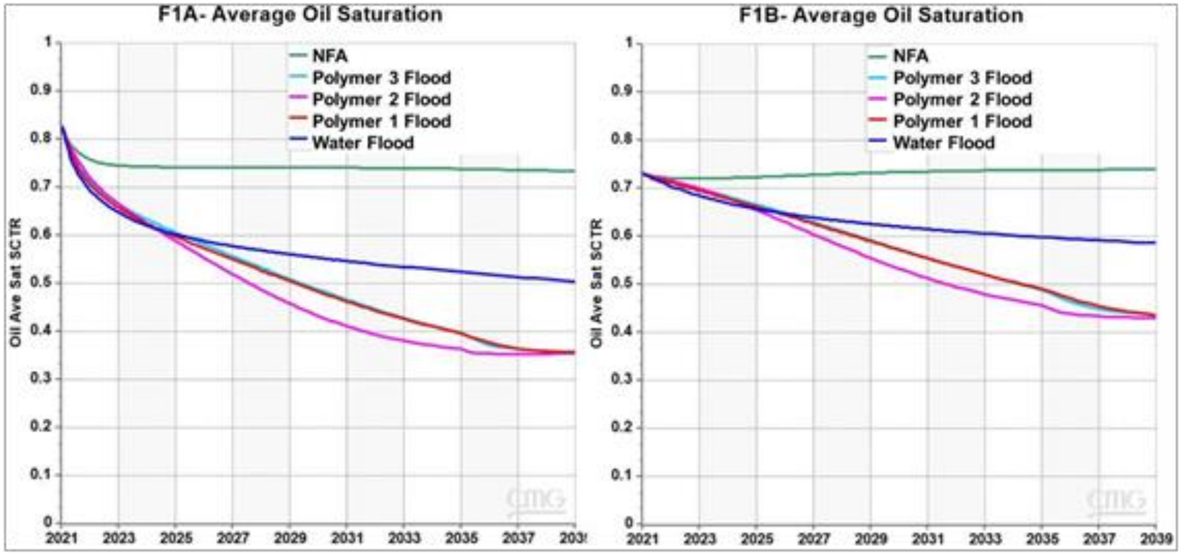

Figure 19: Oil desaturation NFA, water and polymer flood cases for F1A and F1B zones.

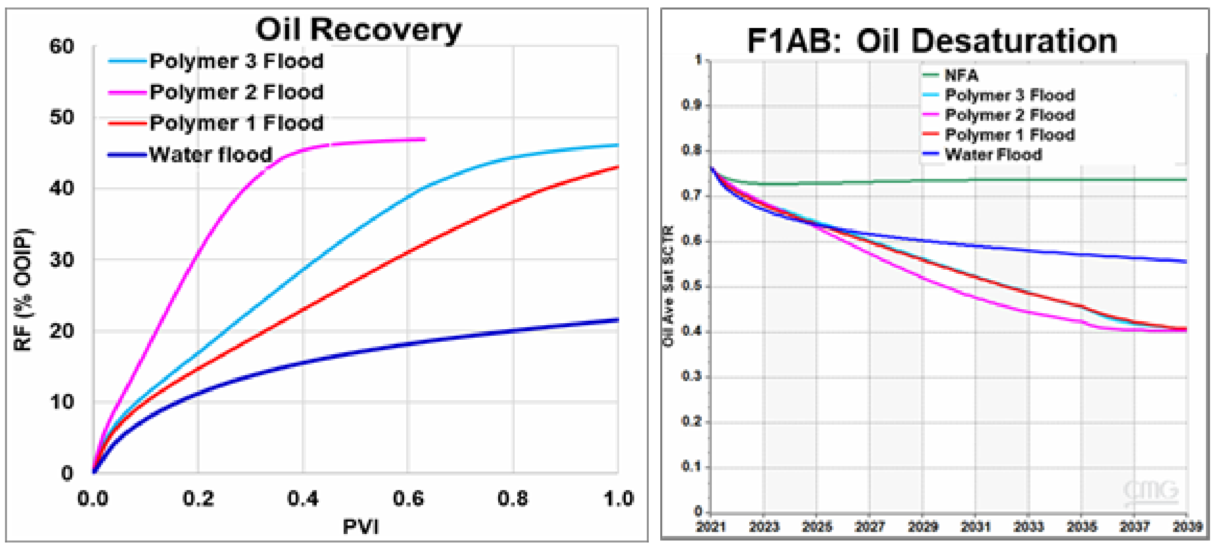

Figure 20: Oil recovery and oil desaturation in water and polymer flooding cases for F1A & B Zones

7.2 Injectivity and Simulated ILT comparison: water flood vs. polymer flood

Water can be injected at a rate of 100 bbl/d without reaching the maximum injection pressure of 350 psi, primarily due to fingering, as illustrated in Figure 20. The maximum achievable injection rate for the polymer solution at this pressure is estimated to be between 220 and 540 bbl/d across all three polymers, as depicted in Figure 20. The injectivity of the polymer flood is lower than that of the water flood, primarily because it approaches the maximum injection pressure limit of 350 psi. The polymer flood exhibits an injectivity index ranging from 1 to 4 bbl/d/psi, as shown in Figure 21. The vertical profile during water flooding indicates that a portion of the water will migrate into high permeability zones, as demonstrated in Figure 22. Simulation results clearly show that the polymer flood presents a more uniform vertical injection profile compared to the water flood, as illustrated in Figure 22.

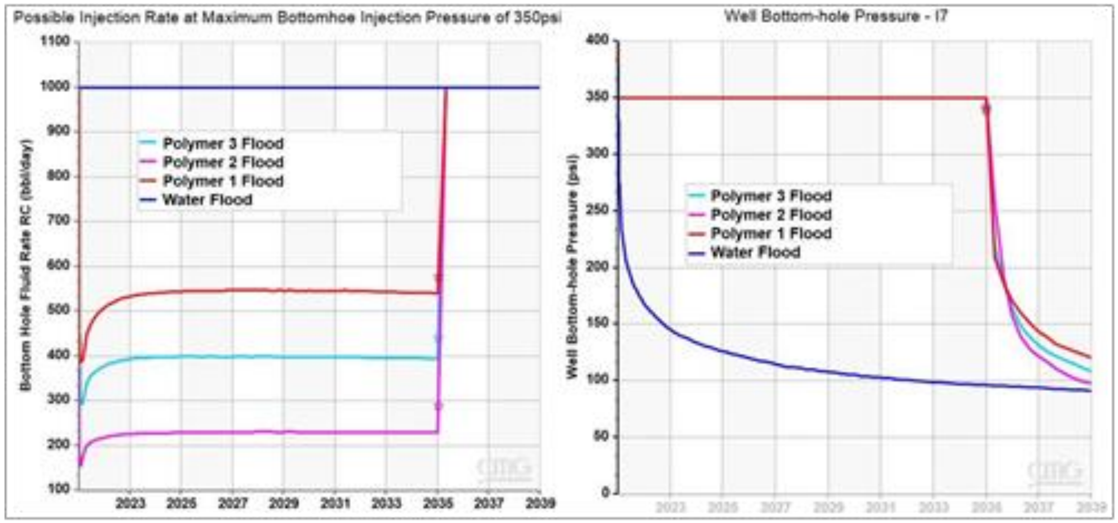

Figure 20: Injection rate and bottomhole pressure in water and polymer flooding cases

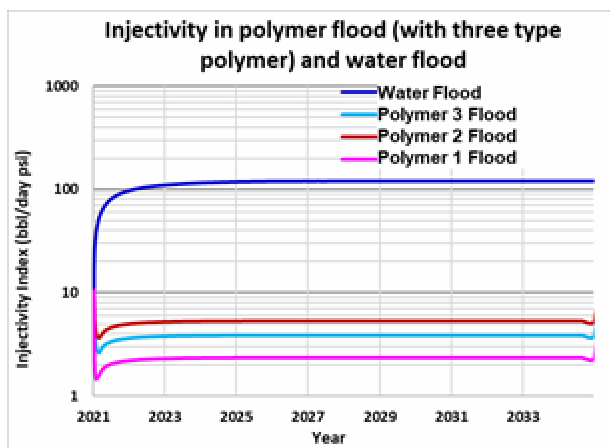

Figure 21: Injectivity index in water and polymer flooding cases

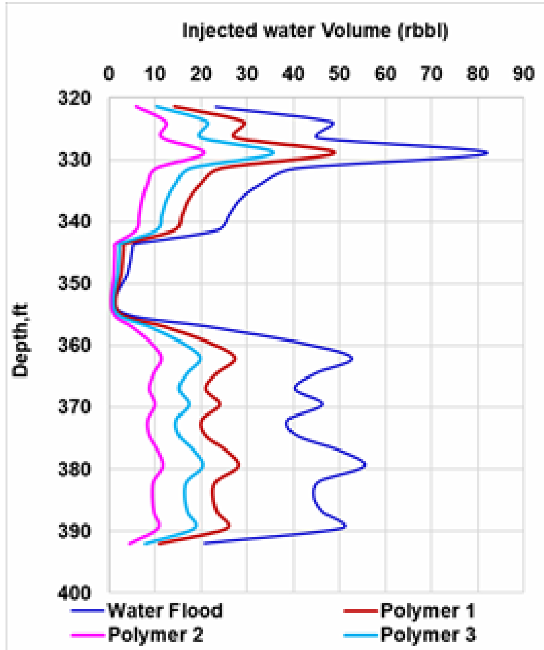

Figure 22: Vertical injection profile of water and polymer flooding cases

7.2 Mobility Ratio comparison Mobility Ratio comparison: water vs. polymer flood

The mobility ratio is the ratio of mobility of displacing fluid to displaced fluid as shown in below equation

$$M = \frac{\lambda_{displacing}}{\lambda_{displaced}} = \frac{(\lambda_{water\ or\ polymer})_{S_{orw}}}{(\lambda_{oil})_{S_{wc}}} = \frac{K_{rw}(S_{orw})/\mu_{water\ or\ polymer\ solution}}{K_{ro}(S_{wc})/\mu_{oil}}$$

Where M, λ, K, krw(Sorw), kro(Swc) and μ are the mobility ratio, mobility, relative permeability of water at residual oil saturation, relatively permeability of oil at connate water saturation and viscosity, respectively.

The average oil viscosity for F1A and F1B zones are 280 and 906 c, respectively. While, the relative permeability of oil at connate water saturation and relative permeability of water at residual oil saturation are 0.3 and 0.07, respectively. The F1A zone exhibits greater oil mobility than the F1B zone. The viscosity of the water phase is approximated at ~1 cp in-situ condition. The water phase mobility is higher in the F1A zone compared to the F1B zone, attributed to the variation in oil viscosity. The mobility ratio was calculated for water and polymer flooding as depicted in Table 3. The mobility ratio for water flood in F1A, F1B and F1AB calculated as 56, 211 and 158, respectively. In order to maintain a mobility ratio close to one from the polymer flooding, it is necessary for the polymer viscosity in the F1A zone to be 65cp and in the F1B zone to be 211cp. Achieving these viscosities is nearly unfeasible due to the limitations on polymer economic concentration; specifically, a maximum viscosity of 53 cp can be attained with 3200 ppm of polymers 2 at 32 degrees Celsius. At a polymer viscosity of 53 cp, the possible mobility ratios are calculated to be 1.2 for F1A and 4 for F1B, as detailed in Table 3. Therefore, the polymer-2 flooding shows huge mobility reduction compared to water flooding i.e. from 158 to 3.

Table 3: Mobility ratio calculation from analytical method for water and polymer flooding cases

Zone	In-situ Oil Viscosity (cp)	In-situ Water Viscosity (cp)	Kro at Swc	Krw at Sorw	Mobility Ratio in Water Flood	Mobility ratio using Polymer 1 (24cp at 2000ppm)	Mobility ratio using Polymer 2 (53cp at 3200ppm)	Mobility ratio using Polymer 3 (33cp at 3300ppm)	Polymer viscosity needed to achieve mobility ratio=1
F1A	280				65	2.7	1.2	2.0	65.3
F1B	906	1	0.3	0.07	211	8.8	4.0	6.4	211.4
F1A B	677				158	6.6	3.0	4.8	158.0

Conclusion

The subject heavy oil reservoir has oil mainly in F1A and F1B zones, while very limited oil only in north and south- west area of F2A and F2B zones. This reservoir presents several challenges for polymer flooding, including the variability of heavy oil viscosity, which ranges from low in the north to high in the south, specifically 50-2500 cp in the F1A zone and 50-2500 cp in the F1B zone. Additionally, the formation water exhibits a hardness of 45,000 ppm, and its salinity varies from 10,000 to 70,000 ppm in the north to southwestern direction, with the F1B zone displaying higher salinity than the F1A zone. Consequently, there is a challenge to select an appropriate polymer in the laboratory that can maintain and deliver the desired viscosifying power is a complex task. Although polymer flooding is not feasible with a favorable mobility ratio i.e. ≤1, it has the potential to enhance the performance of this heavy oil reservoir by reducing the mobility ratio in comparison to water. The findings from laboratory and reservoir simulation evaluations of the polymer flooding in heavy oil reservoirs are summarized as follows:

- The polymers selected for use with produced water as an injection source demonstrated an excellent filterability ratio (approximately 1), robust thermal stability (90 days at 70°C), minimal adsorption (103- 130 µg/g rock), and achieved the desired viscosifying power with a viscosity range of 24-53 cp at an economical concentration.
- An inverted 7-spot injection pattern with a well spacing of 80 meters was identified as optimal for both water and polymer flooding.
- The F1A zone exhibited a higher desaturation and oil recovery factor compared to the F1B zone, primarily due to differences in oil viscosity.

- In the primary depletion scenario (NFA case), oil recovery was poor, yielding only 10% and 2% of original oil in place (OOIP) in the F1A and F1B zones, respectively.
- Water flooding can achieve oil recovery of 40% and 20% in the F1A and F1B zones, respectively.
- The incremental oil recovery by polymer flooding using three selected polymers ranges from 12- 14% for the F1A zone and 20% for the F1B zone.
- SNF Polymer 1 facilitates a quicker acceleration of oil with reduced polymer viscosity index (PVI) injection in both the F1A and F1B zones.
- The mobility ratio for the three types of polymers is observed to be between 1.2 and 2.7 for F1A, and between 4 and 6.6 for F1B.
- F1A provide higher oil desaturation as well as oil recovery factor compared to F1B due to mainly oil viscosity difference

Nomenclature

CSS	:	*Cyclic steam*
K	:	*Permeability (mD)*
KOC	:	*Kuwait Oil Company*
Kr	:	*Relative permeability*
M	:	*Mobility ratio*
NFA	:	*No field activity*
OOIP	:	*original oil inplace*
Sorw	:	*Residual oil saturation*
SR	:	*South Ratqa*
SRQL	:	*South Ratqa Lower*
λ	:	*Mobility*

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