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First Ever Polymer Flood Field Pilot to Enhance the Recovery of Heavy Oils on Alaska's North Slope Pushing Ahead One Year Later

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Abstract

In June 2018 the team embarked on an ambitious project to address the slow development pace of Alaska's 20+ billion barrels heavy oil resource via the first ever polymer flood pilot. Following the successful commencement of the pilot in August 2018, the field demonstration, supporting laboratory experiments and numerical simulation have steadily progressed. A significant amount of valuable data and lessons learned have been collected, and are reported in this paper. The ongoing pilot and the research activities is making headway toward the primary objective of validating the use of polymer flooding for extracting heavy oil in Alaska's challenging environment.

The pilot is conducted in two pre-existing pairs of horizontal injectors and producers in an isolated fault block of the Schrader Bluff heavy oil reservoir at the Milne Point Field. A customized polymer blending and pumping unit injects HPAM polymer at a concentration of 1,750 ppm to achieve a target viscosity of 45 cP. Supporting coreflood laboratory experiments have focused on quantification of polymer retention in the rock, and effect of injection water salinity, polymer, and their combinations on oil recovery. The injection and production response of the pilot flood pattern is utilized to develop a history matched reservoir simulation model for forecasting oil recovery beyond the pilot. Finally, specially designed laboratory experiments address anticipated operating concerns regarding post-polymer breakthrough such as oil-water separation efficiency and polymer induced fouling of heater tubes.

Polymer has been injected continuously since startup except for two short equipment modification shutdowns, and more recently a prolonged disruption due to polymer hydration issues at the J-pad field site. Cumulatively, over 600,000 lbs. of polymer has been injected, corresponding to #7%PV. The two producers show significant decrease in the water cut, gradually increasing oil rate, and no polymer breakthrough. Two main observations from the coreflood are a significant uncertainty in polymer retention values, and positive oil recovery response to low salinity water (2,600 mg/liter TDS). The heterogeneity in the flood pattern presents some challenges in obtaining a robust history matched simulation model. Experimental results

on produced fluids treatment indicate the formation of a dense polymer deposit, at certain conditions, on heating tubes that can negatively impact the heat transfer efficiency.

The scientific knowledge, including the lessons learned during unanticipated shutdowns, quality control, logistics and field data that is being acquired from this effort has referential value for other planned EOR projects. Finally, by all indications, the polymer field pilot is steadily progressing toward achieving the ultimate goal of unlocking the massive heavy oil resources on Alaska North Slope (ANS).

Introduction

Alaska North Slope's (ANS) viscous and heavy oil resources have been extensively reported in many notable publications such as Paskvan et al. (2016) and Targac et al. (2005). In our previous papers (Dandekar et al., 2019; Ning et al., 2019) we described these vast oil deposits in terms of their salient features such as shallow vertical depths, relatively lower pressures and temperatures, and their high viscosities. Therefore, for the benefit of the reader and for completeness of this paper a summary is included here.

The 20 – 30+ billion barrels of high viscosity oil resources on the ANS include two categories, namely "viscous oils" and "heavy oils". Viscous oil deposits are in the Schrader Bluff formation, also called West Sak on the Western North Slope, whereas the heavy oil deposits are in the Ugnu formation, which overlies the Schrader Bluff formation across the North Slope fields. The typical vertical depth and viscosity ranges of viscous oils is 2,000 – 5,000 ft, and viscosities from 5 – 10,000 cP, whereas the heavy oil deposits are much shallower in the vertical depth range of 2,000 – 4,000 ft and viscosities upto a million+ cP, respectively. Paskvan et al. (2016) delineate the vertical depth vs. oil viscosity relationship for the various ANS oil resources. The main focus of this paper is on the viscous oils in the Schrader Bluff formation in the Milne Point Unit (MPU). However, in this paper we use the industry adopted, all-inclusive term "heavy oil".

Despite such a large resource base that represents about a third of ANS' known original oil in place (OOIP), unfavorable factors such as high development costs, significant logistical and environmental challenges, and low oil recovery using conventional techniques stunted the development pace. The limited applicability of conventional techniques, either in part or whole, can be readily realized from factors such as poor volumetric sweep efficiency in a waterflood; significantly high minimum miscibility pressures (MMP) in a miscible gas injection and most importantly potential thawing of permafrost by deploying thermal methods. Some of the prime motivating factors, such as favorable reservoir characteristics of Schrader Bluff, initial scoping studies suggesting significant increase of heavy oil recovery using polymer flooding, and its proven success in Canada and China, however, outweigh the aforementioned technology challenges. Finally, the existing pairs of horizontal injector-producer readily available in Schrader Bluff to conduct the first ever field laboratory experiment to test the polymer flooding "proof of concept" lead to the significant investment by the US Department of Energy and the field operator Hilcorp Alaska LLC. The project team, in earnest, embarked on this ambitious endeavor in June 2018, followed by successful start-up of the pilot in the end of August 2018. With nearly a year and half elapsed, a significant amount of lessons have been learned and valuable field and supporting laboratory data has been collected, which also is complemented by numerical reservoir simulations.

Summary of Polymer Field Pilot and Supporting Research Activities

In our previous publications (Dandekar et al., 2019, Ning et al., 2019) a detailed description of the polymer field pilot area and test wells was provided. Therefore, only a summary of key elements is included here for completeness.

The pilot is conducted at the J-pad of the Milne Point Unit in the horizontal well patterns that consists of two injectors (J-23A and J-24A) and two producers (J-27 and J-28) drilled into the Schrader Bluff NB-sand. The lengths of the horizontal sections range from 4,200 to 5,500 feet whereas the inter-well distance is approximately 1,100 feet. Prior to the commencement of the pilot, this pattern was waterflooded, which resulted in an oil recovery of 7.6% and water cut as high as 67%. Polymer injection started on August 28, 2018 at both injectors via a polymer slicing unit (PSU) which was custom designed and manufactured for this project for operability in the Arctic environment. HPAM polymer powder is mixed with water to prepare a mother solution, which is then diluted to the desired concentration (#1,750 ppm), after 100 minutes of residence time in the tank. The water used for making polymer solution is produced from a source water well J-02 (also at the J-pad) which provides relatively fresh water supply with total dissolved solids (TDS) of 2,600 milligrams per liter. In order to avoid shearing, the polymer solution is injected by 3 positive displacement pumps.

The polymer field pilot activities are complemented and supported by various research activities in parallel that include laboratory corefloods to determine the retention of polymer, effect of injection water salinity and polymer solution made up with waters of different salinities. Numerical reservoir simulation models of the flood pattern also are built by history matching the previous waterflood and polymer pilot field data to forecast oil recovery scenarios, by considering sensitivity of various parameters, beyond the pilot. Although, polymer is yet to breakthrough in either of the production wells, there are two major operational concerns that need to be addressed a priori before this occurs, since they have the potential to negatively impact an otherwise successful pilot. Both pertain to the processing of the produced stream; one is related to the effect of polymer on oil-water separation efficiency, while the other is related to the polymer induced fouling issues in the heat exchanger used in Milne. These are tackled by conducting specialized laboratory experiments that provide practical operational guidance for the ongoing polymer field pilot.

Results and Discussion

The primary objective of this paper is to report on the summary of various facets of the successful continuation of the polymer pilot. Therefore, in the following sub-sections, only selected results and their discussion are presented. For other specific details the reader is referred to our topical publications on polymer retention (Wang et al., 2020); oil-water separation (Chang et al., 2020); polymer induced fouling of heater tubes (Dhaliwal et al., 2020); and polymer injection performance (Ning et al., 2019).

Polymer Field Pilot Performance

Since the start of HPAM polymer injection on August 28, 2018, the pilot has continued almost seamlessly, barring some operational setbacks, which we report on in the following sub-section. Various operational parameters and quality controls such as polymer concentration, viscosity, and filter ratio, have been closely monitored and adjusted. Similarly, operational procedures have been improved to ensure adequate injectivity and polymer propagation through the formation. Performance of the pilot is monitored via polymer injection rate and pressure, oil and water production rates, and the weekly analysis of produced water for polymer content. Tracers have been pumped pre and post polymer injection startup to compare polymer flood breakthrough timing and sweep efficiency.

Average J-pad polymer concentration and viscosity are measured daily, which is shown in Figure 1. In order to achieve the target viscosity, which was initially set at 45 cP and later adjusted to 40 cP, polymer concentration has varied between 1,600 to 1,800 ppm during the injection period. The polymer injectivity is diagnosed by a Hall plot (Hall, 1963), which graphs the integration of the differential pressure between the injector and the reservoir versus cumulative water injection. As seen in Figure 2, after a decrease in the injectivity earlier, current Hall plot diagnostic indicates that the injectivity of both J-23A and J-24A has stabilized. By mid-February 2020, approximately 410,000 lbs. of polymer have been injected into J-23A and 190,000 lbs. into J-24A. Total cumulative volume of polymer solution injected is approximately 1.2 million barrels representing 7% of the total pore volume in the flood pattern.

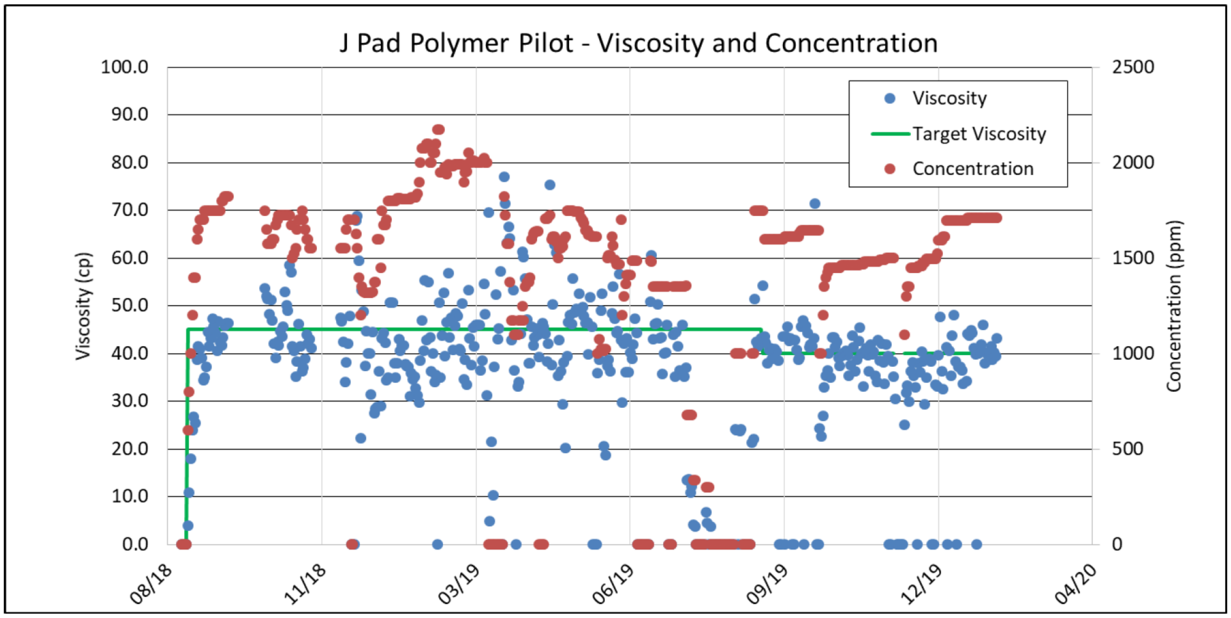


Figure 1—J-pad polymer solution concentration and viscosity vs. time.

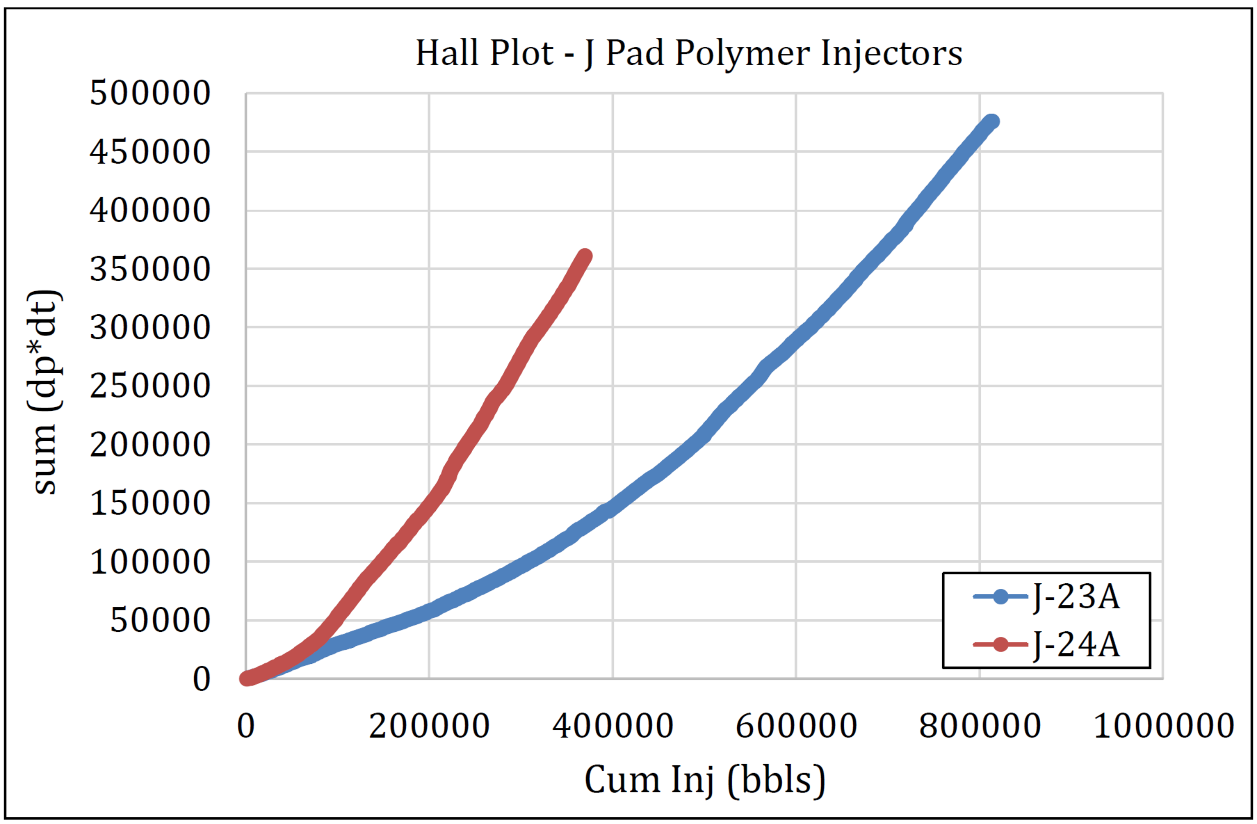


Figure 2—Hall plot of J-23A and J-24A injectors.

The pre and post polymer injection response of the two producers, J-27 and J-28, is depicted in Figures 3 and 4 respectively. Both producers show a significant decrease in the water cut from #70% to 15%, which is the best indicator that the injected polymer is helping improve sweep efficiency. The data from both producers also show that the oil production rate has stabilized in J-27 and is increasing in J-28. Additionally, no polymer production has been confirmed from the two horizontal producers after 18 months of polymer injection.

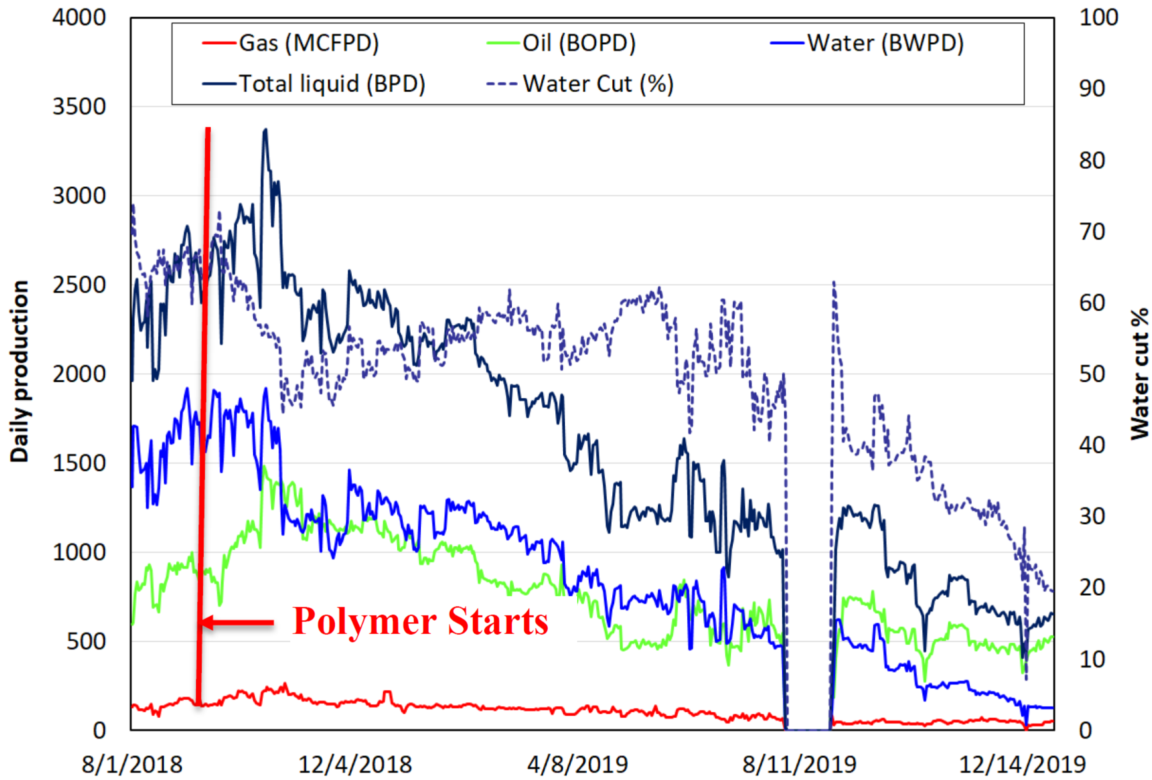


Figure 3—J-27 production performance.

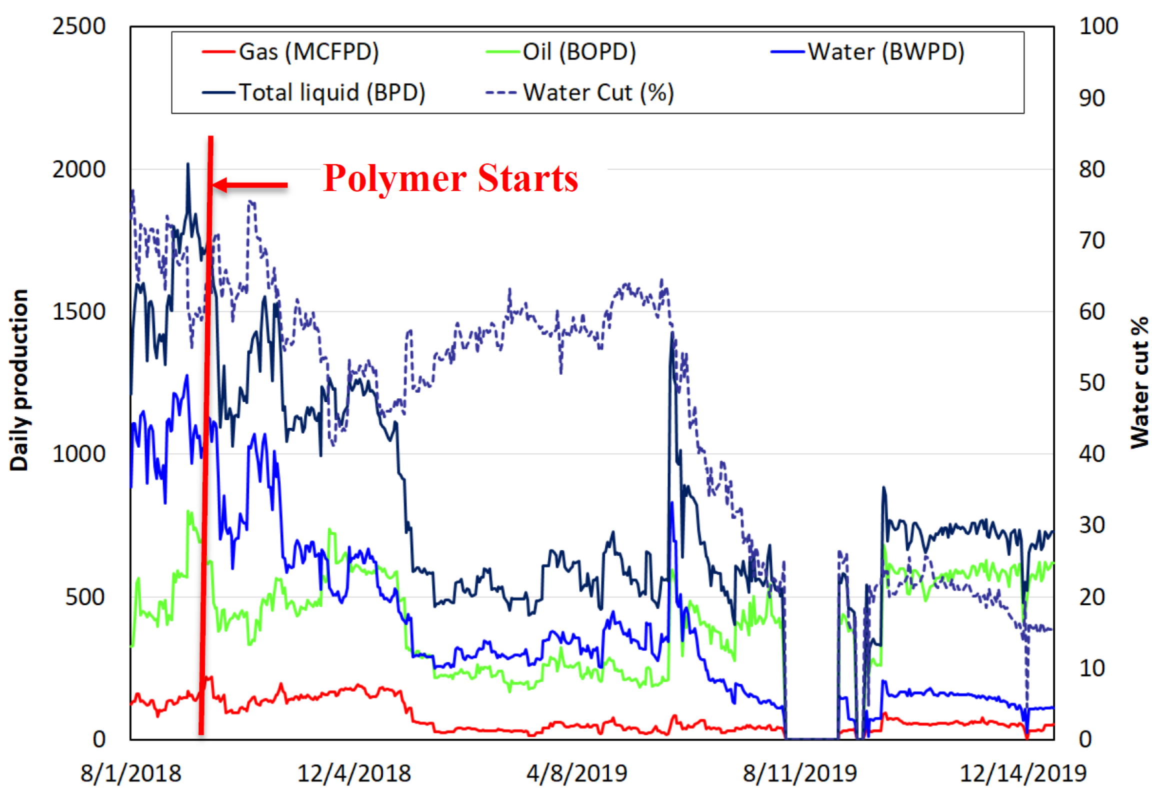


Figure 4—J-28 production performance.

Voidage Replacement Ratio (VRR), which is defined as the ratio of the injection volume to production volume at reservoir conditions, is a metric that is often used to assess the efficacy of an injection process (in particular a conventional waterflood). A VRR of 1 is quite often considered as an indicator of the stability of the displacement and pressure maintenance. As seen in Figure 5, in our case during the first 4 months of polymer injection from August to December 2018, instantaneous VRR<1 means that the polymer injection volume was less than the production voidage. However, since January 2019, instantaneous VRR>1 means that the polymer injection volume was greater than the production voidage due to the decline in total liquid (oil + water) production rate (see Figure 3 and 4). Cumulative VRR of the project pattern was 0.85 at the beginning of polymer injection and currently at # 0.88 meaning that we have injected more polymer solution than the production voidage during the last 18 months. Note that this is the delta VRR of 0.03, which is relative over WF prior to polymer startup. In order to increase oil production rate, the current plan is to continue to over inject to catch up with the voidage replacement to elevate the reservoir pressure to its initial value.

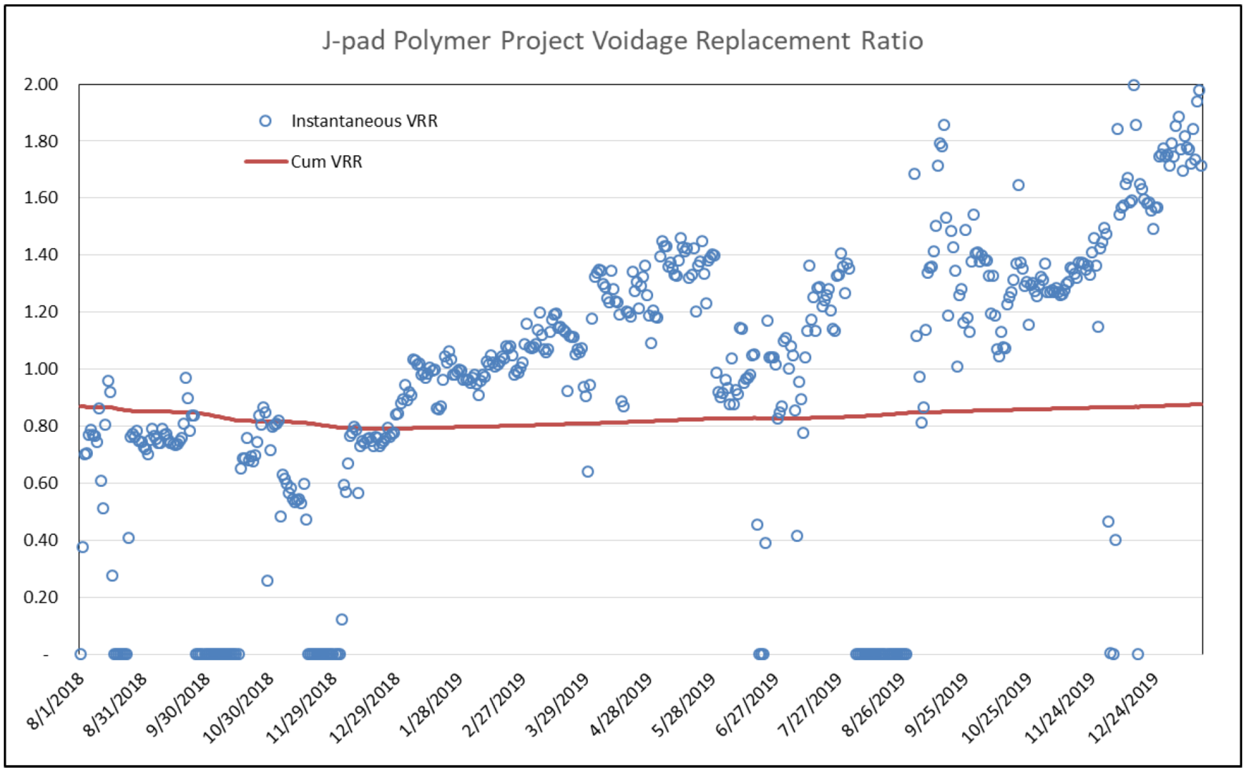


Figure 5—Instantaneous and cumulative VRR.

Operational setbacks and lessons learned.. As one would expect in an endeavor of this scale, the polymer field pilot did experience a number of operational setbacks from which the team learned many useful lessons such as polymer properties, polymer facilities, and the required onsite quality control (QC), in a particularly challenging Arctic environment. The following is the timeline of these episodes: (1) PSU shutdown on 9/25/2018 due to hydrocarbon gas in source water, modified and reclassified PSU to Class I Div. II, injection resumed on 10/15/2018; (2) J-23A and J-24A shutdown on 11/9/2018 and 11/16/2018 respectively for PFO awaiting pump repairs, injection resumed on 12/3/2018; (3) PSU shutdown on 6/19/2019 due to polymer hydration issues, and after extensive trouble shooting injection fully resumed on 8/29/2019. The main lessons learned, from which other similar projects can benefit, are summarized below.

1. QC is much more important for polymer flooding compared to standard waterflooding operations.
2. Injecting poorly hydrated polymer, or bad polymer quality will have a direct impact on injectivity.
3. Polymer units should be capable of handling/tolerating fines and gas in the source water and have sufficient residence time.

4. Polymer unit design should not rely on a single water sample. For example, the source water sample we initially collected did not fully detect the presence of methane and fines.

Polymer Retention

One of the most significant parameters in any polymer flood is the retention of polymer (µg/g of rock) due to entrapment and adsorption. The retained polymer is basically rendered ineffective in the displacement process, which is quantified by pore volume (PV) delay factor (Seright, 2017). Polymer retention values are commonly measured by laboratory coreflood in which the relative values of carbon, nitrogen and viscosity vs. PV of polymer injection is tracked. Note that carbon and nitrogen fluorescence values are considered much more reliable given the presence of these elements in the HPAM structure (Seright, 2017). In order to assess this for the subject set of rock and fluids and the polymer, several retention experiments have been carried out so far (see Wang et al., 2020). An example of one such test is shown in Figure 6. The polymer retention data measured on several sandpacks vs. their absolute permeabilities is plotted in Figure 7. Although, the trend suggests that retention is inversely proportional to absolute permeability for NB#3 and OA sands, it does not necessarily correlate with the NB#1 sand. The significant differences in the retention values of all the tested samples, despite the similarity in their elemental and clay compositions, is particularly intriguing. The challenges encountered while determining polymer retention values for the pilot, therefore, continues to be a topic of further investigations.

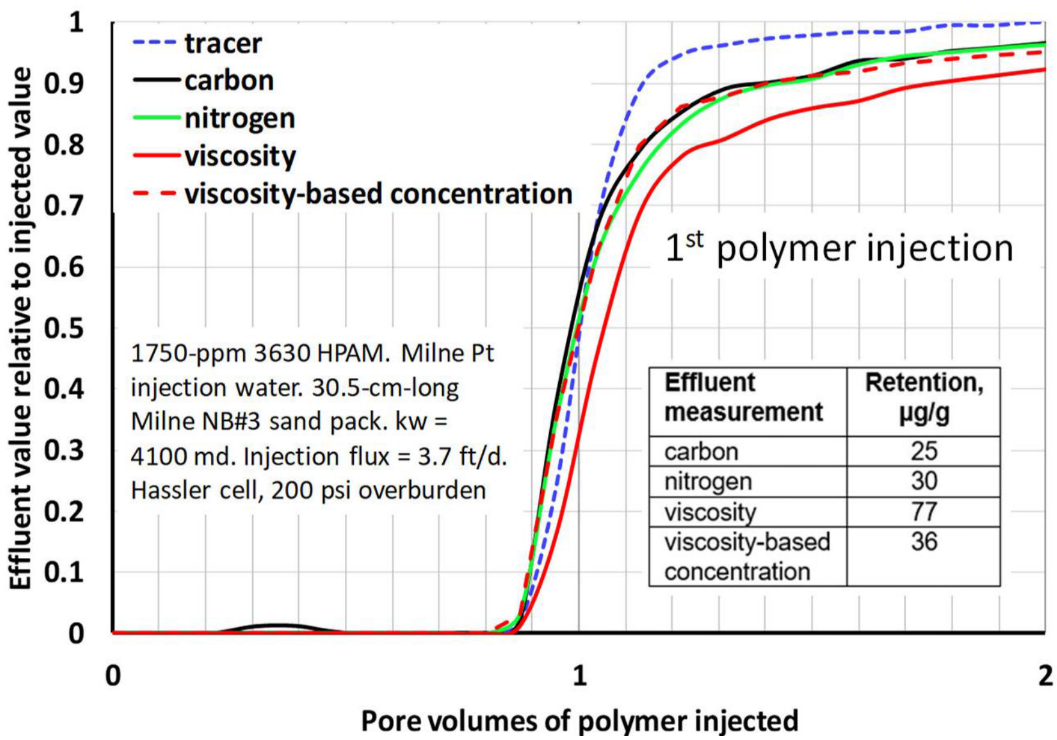


Figure 6—Polymer retention experiment data for the Schrader Bluff NB#3 sandpack (Wang et al., 2020).

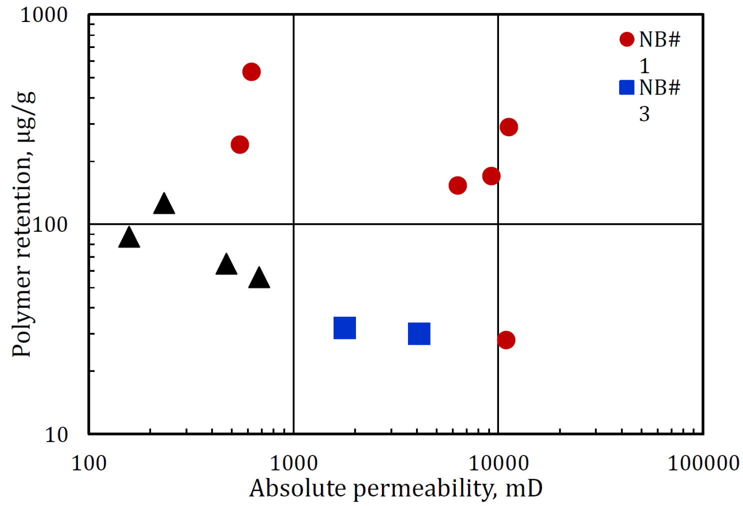


Figure 7—HPAM (3630S) polymer retention data vs. absolute permeability for various Schrader Bluff sandpacks.

Injection Water Salinity and Polymer Synergistic Effects

A series of coreflooding experiments have been carried out in order to get a deeper understanding of the enhanced oil recovery mechanisms of polymer flooding in heavy oil reservoirs. These experiments include the investigation of salinity effect alone, polymer solutions made with waters of different salinities, and their effect on the oil recovery. Similar to the retention experiments, all corefloods in this case also utilized the representative rock and fluid systems. The typical flooding sequence in these tests is conventional (usually high salinity formation water) waterflood (WF), followed by low salinity waterflood (LSWF), low salinity polymer flood (LSPF) and finally the high salinity polymer flood (HSPF). Note that the polymer solution viscosity in both polymer floods is #45cP. Figure 8 shows the results for a sandpack for this particular flooding sequence. As seen in Figure 8, consistent results have been observed in all other corefloods that demonstrate positive effect of low salinity water and low salinity polymer on oil recovery, and almost no incremental oil recovery from the high salinity polymer flood.

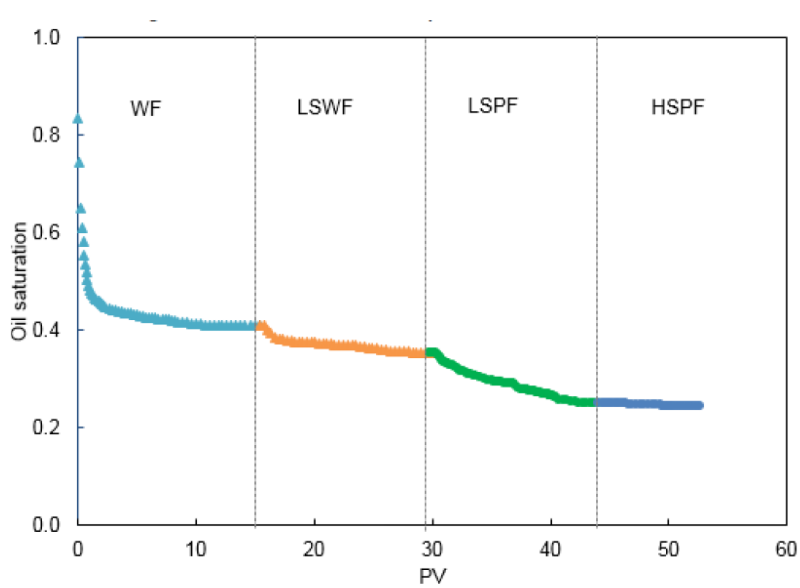
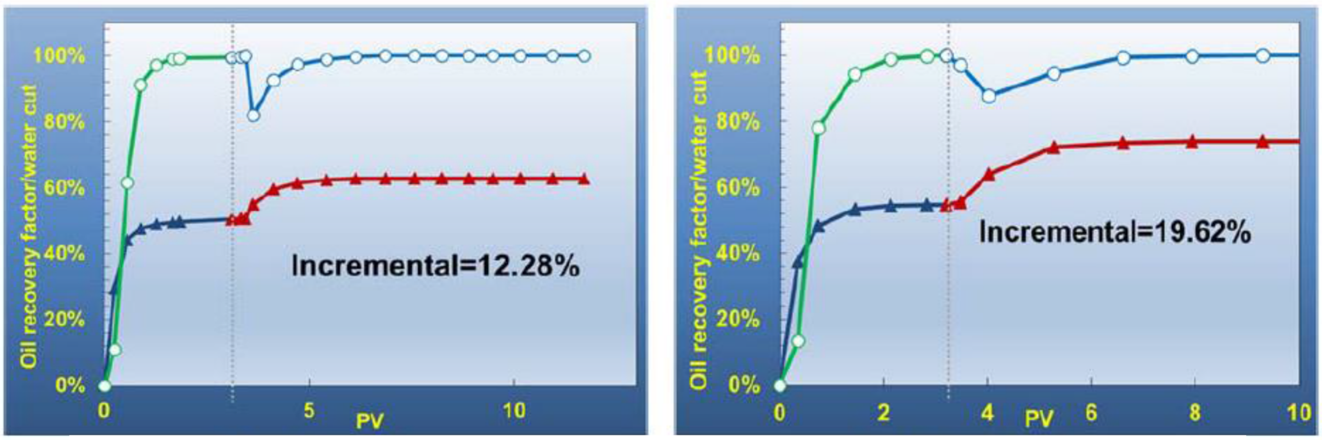


Figure 8—Oil saturation vs. PV injected for NB sand corefloods.

As part of our investigation on the mechanisms that contribute to improved oil recovery by the low-salinity polymer process vs. high-salinity polymer process, coreflooding experiments were carried out to evaluate the displacement performance of the respective polymer solutions. However, due to the limited amount and poor consolidation of Milne NB formation sand, Berea sandstone cores were used. In these experiments polymer solutions were prepared with low salinity and high salinity waters respectively, but both of approximately the same 45 cP viscosity. Figure 9 shows the results for these tests that demonstrate the superior performance of low salinity polymer compared with high salinity polymer of similar viscosity. Our initial experimental observations appear to be consistent with previous literature (Al-Qattan et al., 2018; Khorsandi et al., 2017; Unsal et al., 2018; Vermolen et al., 2014).



(a) High-salinity polymer (b) Low-salinity polymer

Figure 9—Water cut (top curve) and oil recovery (bottom curve) for high and low salinity polymer solutions of similar viscosity.

Reservoir Simulation of Flood Pattern

The 3D grid system of the reservoir simulation model of the flood pattern is based on the geological model which was developed by combining seismic data, well logs, core data as well as wellbore trajectories and configurations. One of the major challenges that we faced, however, was the proper representation of permeability heterogeneity. In order to account for this, three different models were built, namely the layercake, block/stripe, and a heterogeneous model respectively. Each case has the same number of total and active gridblocks. As an example, the heterogeneous model is depicted in Figure 10. All three models were eventually employed in history matching the actual water cut. Unfortunately, the simulated water cuts of both J-27 and J-28 significantly differed (not shown here) from the actual production data no matter which model is used; in other words, a poor history match.

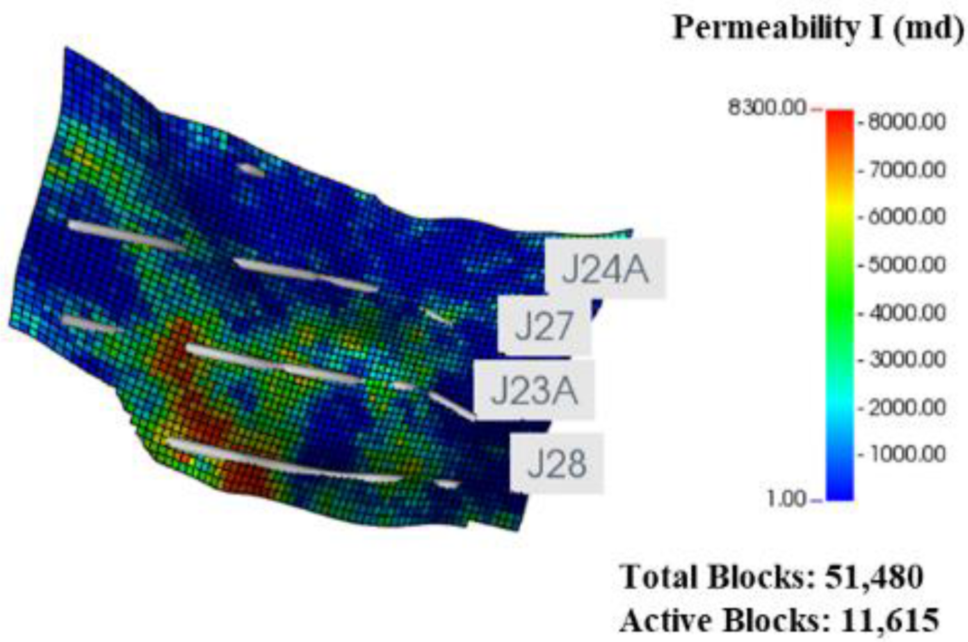


Figure 10—Heterogeneous permeability distribution in the simulation model of the flood pattern.

The unconsolidated nature of the formation in the flood pattern gave the clue in solving the unsatisfactory history match problem. It was construed that water injection into such unconsolidated formation would lead to the movement of sand thereby generating time-dependent high permeable channels, which were impossible to account for and thus the failure to obtain a robust history match, as mentioned before. Therefore, we arbitrarily placed two high permeable channels between the adjacent injection and production wells in the heterogeneous model, resulting in six channels in total. As an example, Figure 11 shows the two channels that link producer J-27 with injectors J-23A and J-24A. The subsequent step was to consider the water transmissibility multipliers (given the high permeability of channels) which were tuned manually along with the widths of the channels to history match the water cut data.

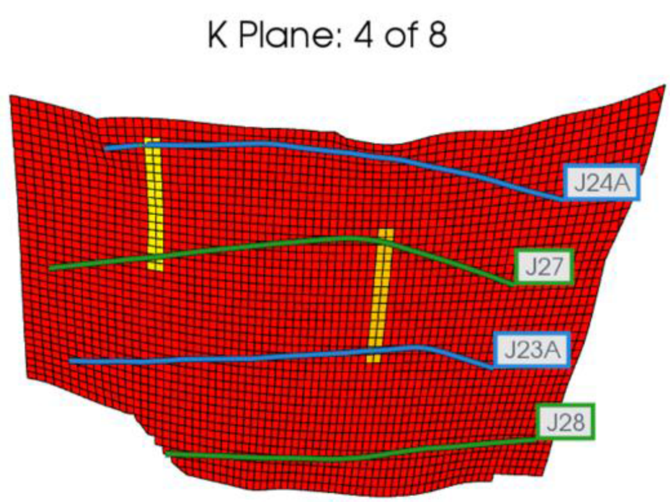


Figure 11—Placement of high permeable channels in the heterogeneous simulation model.

The history matching results of water cut for waterflood alone and the subsequent polymer flood for producer J-27 is presented in Figure 12. It can be seen that the simulated water cut (blue line) is now consistent with the actual production data (open circles) for the entire waterflooding period and about half of the initial polymer flooding period. This also was the case with producer J-28 (not shown here). Therefore, employing a simulation model with channels (see Figure 11) and altering the permeability of channels with time seems to improve the history matching results. Vis-à-vis this also verifies that high permeability channels can be generated in an unconsolidated reservoir formation during water or polymer injection. However, matching the currently observed low water cuts of the order of 15% continues to be a challenge that we are tackling. Once this is resolved, future focus of the updated reservoir simulation model is sensitivity analysis of various parameters such as injection rate, polymer concentration and retention on oil recovery to support and optimize the field pilot.

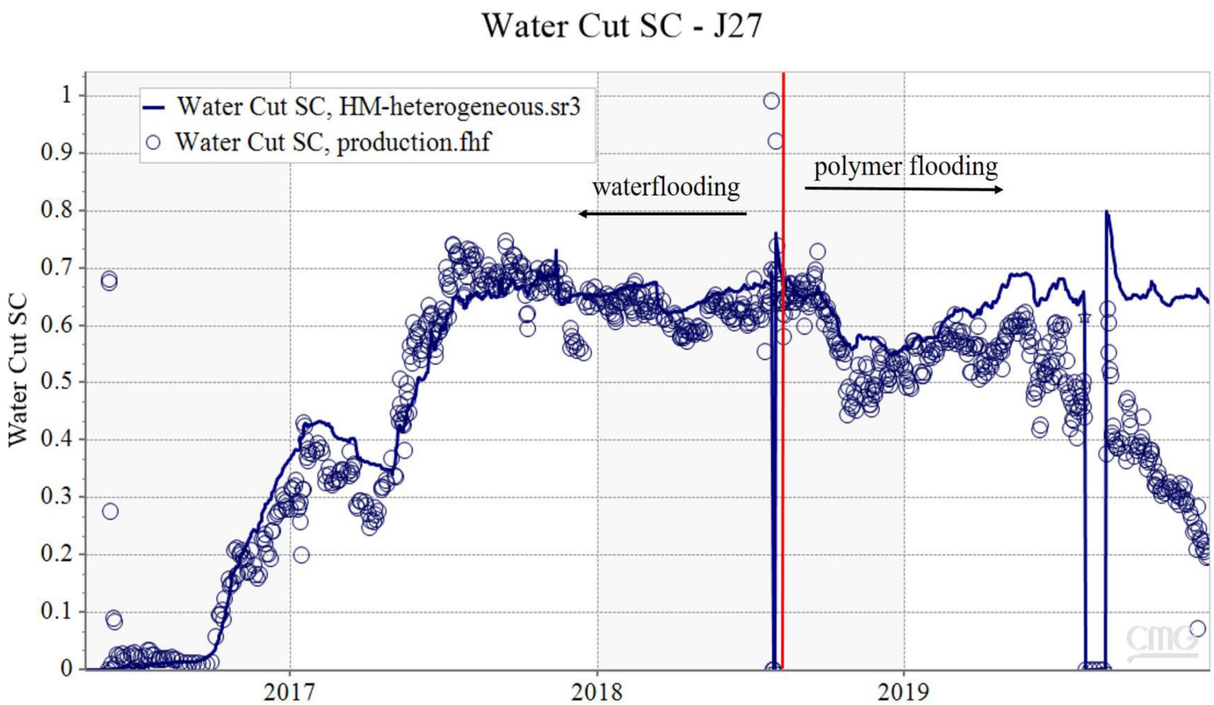


Figure 12—Improved water cut history match of producer J-27 based on high permeable channels – solid blue line is simulation and open blue circles is field production data.

Oil-Water Separation and Polymer Induced Fouling of Heater Tubes

Extensive laboratory tests have been conducted to date to investigate the separation behavior of heavy oil water emulsions. Given the fact that emulsion breakers (EB) are time-tested and commonly employed on ANS for oil-water separation, all experiments have focused on testing their effectives based on performance indicators such as demulsification efficiency, required dosage, clarity of separated water and separation speed. Another important metric is the time required by the EB to get to the demulsified state because typical residence time in a process separator is only 5-15 minutes. This was not explicitly tested, but instead we used separation speed. Experimental protocols have been discussed in our other papers (Dandekar et al., 2019 and Chang et al., 2020). The water cut generally dictates the type of EB to be used, i.e., oil or water soluble, accordingly given the various ranges of water cuts, three different oil soluble and one water soluble EB has been tested. Some tests have also included the use of compound EB's, such as the mixtures of two individual ones. The performance of two oil soluble EB's (E12 and its compound with E18) for various dosages, at a 20% water cut (close to the current observed value in the pilot) and 150 ppm polymer concentration is shown in Figure 13 in terms of the separation efficiency and oil content. Although, the separation efficiency of both is comparable, the compound EB is slightly superior in terms of (low) oil content in water. A similar performance of the compound EB was observed also in the case of 50% water cut and 800 ppm polymer concentration, as indicted by the close to one value of the four performance indicators (Figure 14).

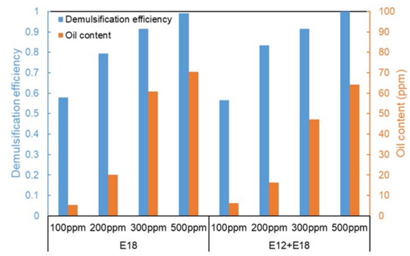


Figure 13—The effect of EB dosage and type on performance for a 20% WC emulsion with 150ppm HPAM polymer.

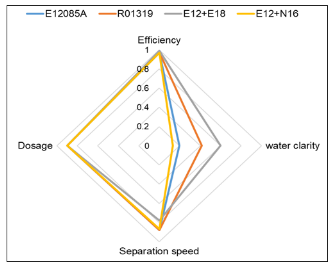


Figure 14—Spider chart for tested EBs for a 50% WC emulsion with 800ppm HPAM polymer.

All fouling tests have been conducted in a set-up designed and built at UAF. The main components are a 0.25 inch OD and 10-inch-long U-shaped metal (copper, carbon steel and stainless steel) tube, submerged in the testing solution containing produced brine and HPAM polymer, which is heated to various test temperatures by circulating hot oil inside the tube. The testing solution that is initially at 77°F is heated to 122°F by the internally circulated hot oil, to mimic the inlet and outlet conditions in the heat exchanger currently in use at the pilot site. After reaching the desired testing solution temperature, it is replaced with a fresh batch and again heated to 122°F, but using the same U-tube. This sequence is repeated 5 times (named as 5 runs) and after the termination of the test, the cumulative deposit or fouling of the outside of the U-tube is quantified by mass balance and the solid deposit subjected to XRD and SEM analysis. The logic behind the repetitive testing lies in the fact that the same heat exchanger tubes (U-tube in this case) would be heating the continuously flowing produced fluids stream (testing solution in this case). Figure 15 shows that the deposit on the copper tube with and without polymer generally increases with the skin temperature of 250 and 350°F, but a significantly lower and nearly constant rate of deposit is seen in the case of 165°F and 200°F. In other words, note the major shift between 200°F and 250°F. Since the deposit will have a negative impact on the heat transfer efficiency, the data obtained on copper tube at least suggests a threshold skin temperature of 200°F. Details on experimental procedures and other results are discussed in Dhaliwal et al. (2020).

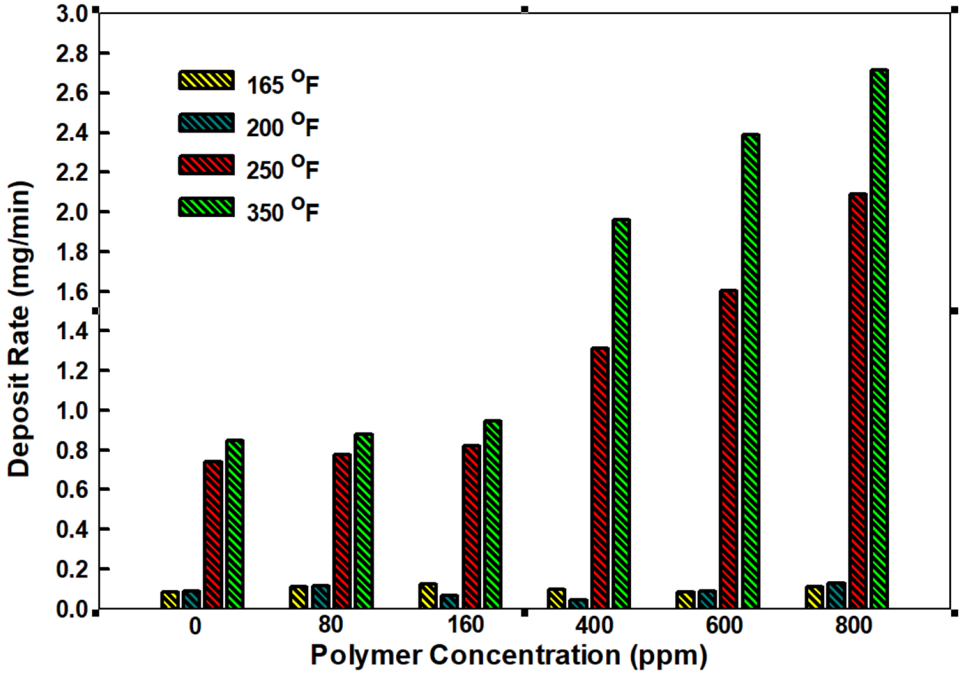


Figure 15—Deposit rate (cumulative deposit/total heating time) on copper tube vs. various HPAM polymer concentrations at the tested skin temperatures.

Conclusions

Based on the research conducted so far, the following main conclusions are drawn:

- With nearly one and half years of polymer injection in the two horizontal injectors, no severe injectivity issues nor polymer breakthrough have been encountered.
- Obtaining consistent polymer retention values continues to be a challenge.
- The EOR benefits of low salinity alone and its positive role in promoting oil recovery in polymer flood has been corroborated by laboratory corefloods.
- After undergoing several iterations, reasonable history match has been achieved during waterflood and early times of polymer flood. However, matching the currently observed low water cuts of the order of 15% continues to be a challenge.
- Despite the complicated interactions involved in the formation of heavy oil, produced water, and HPAM polymer emulsions, a compound emulsion breaker has been screened based on extensive testing, for potential application at the polymer field pilot site.
- Based on the fouling tests conducted on copper tubes, the skin temperature of 165°F currently used in the heat exchangers at the pilot site appears to be operationally safe from the standpoint of HPAM stability.
- Finally, given the overall steady progress and the promising indicators of the pilot, since its commissioning in late August 2018, the authors are cautiously optimistic that this positive trend will likely continue and this pilot will eventually be the game changer to enhance the recovery of heavy oils on ANS.

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Nomenclature

3D	Three Dimensional
ANS	Alaska North Slope
cp or cP	Centipoise
bbl	Barrel
BOPD	Barrels Oil per Day
BPD	Barrels Per Day
BWPD	Barrels of Water Per Day
dp/dt	Pressure Derivative of Time
EB	Emulsion Breaker
EOR	Enhanced Oil Recovery
HPAM	Hydrolyzed polyacrylamide
HSPF	High Salinity Polymerflood
LSPF	Low Salinity Polymerflood
LSWF	Low Salinity Waterflood
MCFPD	Thousand Cubic Feet Per Day
md or mD	Millidarcy
MMP	Minimum Miscibility Pressure
MPU	Milne Point Unit
OD	Outside Diameter
OOIP	Original Oil in Place
PFO	Pressure Falloff
PPM	Parts Per Million
PSU	Polymer Slicing Unit
PV	Pore Volume
QC	Quality Control
SC	Standard Conditions
SEM	Scanning Electron Microscope
TDS	Total Dissolved Solids
μg	Microgram
VRR	Voidage Replacement Ratio
WC	Water cut
WF	Waterflood

XRD X-ray Diffraction

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