URTeC: 5077

Heavy Oil Polymer EOR in the Challenging Alaskan Arctic - It Works!

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This paper was prepared for presentation at the Unconventional Resources Technology Conference held in Houston, Texas, USA, 26-28 July 2021.

Abstract

Under co-sponsorship of the US Department of Energy and Hilcorp Alaska LLC the first ever polymer field pilot commenced on 8/28/2018 in the Schrader Bluff heavy oil reservoir at the Milne Point Field on Alaska North Slope (ANS). The primary objective of the pilot is to prove the efficacy of polymer Enhanced Oil Recovery (EOR) to unlock the vast heavy oil resources on ANS. More than two and half years after startup, the polymer injection, supporting laboratory experiments and simulation studies steadily continue. The pilot started injecting hydrolyzed polyacrylamide (HPAM), at a concentration of 1,750 ppm to achieve a target viscosity of 45 cP, into the two horizontal injectors in the flood pattern. Production is monitored in the two horizontal producers. Based on laboratory measurements of polymer viscosity at reservoir conditions, the team decided to reduce polymer concentration to 1,200 ppm since July 2020 in an effort to control injection pressure and optimize polymer utilization. Quality control (QC) on the field ensures uniform polymer solution properties. Representative rock and fluid systems and test conditions are utilized in the corefloods on polymer retention, effect of injection water salinity, polymer loading, and their combinations on oil recovery. A history matched reservoir simulation model for forecasting oil recovery was developed on the basis of all the available field data. Field concerns related to the post-polymer breakthrough impact on flow assurance is addressed via specialized laboratory tests.

Notwithstanding early operational disruptions and hydration issues, continuous polymer injection in both injectors has been achieved. To date, 950,000 lbs of polymer or 2 million barrels of polymer solution, equating to 13% of total pore volume (PV), has been placed in the flood pattern, serving as an effective indicator of adequate polymer injectivity. So far, the success of polymer EOR is evident from drastically reduced water cut in the producers, an estimated incremental 1,000 bopd over waterflood, and a favorable polymer utilization of 1.7 lbs/barrel of incremental oil. Polymer breakthrough was observed 26 months after the start of polymer injection. Main observations from corefloods are unusually high polymer retention values in some cases and a positive response to low salinity water. Although the heterogeneity in the flood pattern and exceptionally low water cut pose some challenges, persistent novel and justifiable simulation approaches have resulted in a robust history matched model. Experimental results on produced

fluids treatment provide operational guidance for improved oil-water separation and mitigation of heater tube fouling.

The ongoing success of the pilot is a key indicator of bringing the team ever closer to meeting the project's primary objective. The encouraging results of the pilot is one of the drivers that has provided the impetus to apply polymer EOR throughout the Milne Point Field, which would increase oil recovery and extend the economic life of the Trans Alaska Pipeline System. The scientific knowledge, including the many lessons learned from this pilot also has referential value for other potential heavy oil EOR projects throughout the world. The collected data, operational lessons learned, and the overall success of the pilot are summarized in the paper.

Introduction

Alaska North Slope (ANS) is endowed with vast high viscosity oil resources that range between 20 – 30+ billion barrels. These are categorized as "viscous oils" and "heavy oils" respectively depending on the depth and proximity to the permafrost. The viscous oil deposits in the Schrader Bluff formation (also called West Sak on the Western North Slope) are relatively deeper (2,000 – 5,000 ft) with in-situ viscosities between 5 – 10,000 cP, whereas the heavy oil deposits in the Ugnu formation are much shallower (2,000 – 4,000 ft) and have viscosities up to a million+ cP. Owing to these depths, the formation temperatures and pressures are generally low. Notwithstanding this categorization, in this paper we use the industry adopted, all-inclusive term "heavy oil". The reader is referred to other topical publications (Dandekar et al., 2019, Paskvan et al., 2016, Targac et al., 2005) that describe these ANS resources in great details. In particular, Paskvan et al. (2016) delineate the vertical depth vs. oil viscosity relationship for the various ANS oil resources. Note that the main focus of this paper is on the viscous oils in the Schrader Bluff formation in the Milne Point Unit (MPU).

The large heavy oil resource base has been marred by several unfavorable factors such as high development costs, challenging arctic environment, logistical constraints, poor waterflood sweep efficiency due to mobility contrasts, inapplicability of typical/standard thermal (due to continuous permafrost) heavy oil recovery techniques, and significantly high minimum miscibility pressures (MMP). However, on the other hand, the aforementioned unfavorable factors are out-weighted by favorable reservoir characteristics of Schrader Bluff, initial scoping studies suggesting significant increase of heavy oil recovery using polymer flooding, and its successful implementation in Canada, China and elsewhere in the world, and the availability of the existing pairs of horizontal injector-producer in Schrader Bluff. This particular impetus leads to the best readily available opportunity for significant investment by the US Department of Energy and the field operator Hilcorp Alaska LLC to conduct the first ever field laboratory experiment to test the polymer flooding technology. After embarking on this ambitious endeavor in June 2018, followed by successful commencement of the pilot in the end of August 2018, many lessons have been learned and valuable field and supporting laboratory data has been collected, which also is complemented by numerical reservoir simulations. Finally, the success to date is our claim that heavy oil polymer EOR works in the challenging arctic environment.

Methodology

In a number of our previous publications (Dandekar et al., 2019, 2020, Ning et al., 2019, 2020) the polymer field pilot area and test wells have been adequately described, which are summarized here for completeness. The pilot that is being conducted at the J-pad of the Milne Point Unit consists of two horizontal injectors and producers, namely J-23A, J-24A and J-27, J-28 respectively, drilled into the Schrader Bluff NB-sand. The lengths of the horizontal sections range from 4,200 to 5,500 ft whereas the inter-well distance varies between 1,100 to 1,500 ft. Prior to starting the polymer pilot, this pattern was used for waterflooding, which was terminated when the oil recovery was merely 7.6% and water cut had reached 70%. August 28, 2018 marked the start of polymer injection in J-23A and J-24A via a polymer injection unit which was custom designed and manufactured for this project for operability in the Arctic environment. The hydrolyzed polyacrylamide or HPAM (Flopaam 3630S) polymer powder is mixed with water to prepare a mother solution, which is then diluted according to the desired injection concentration. In the beginning the polymer concentration was 1,750 ppm, which was reduced stepwise to 1,500 and later to 1,200 ppm (current concentration). A source water well (J-02) which also is at the J-pad provides the low salinity water (Total Dissolved Solids or TDS of 2,600 mg/l) for preparing the polymer solution. The injection of polymer solution is carried out via positive displacement pumps.

On a laboratory and numerical simulation scale, there are four different activities that are conducted in parallel that complement and support the polymer field pilot. These range from the laboratory determination of polymer retention, effect of water salinity and polymer solutions made up with different salinities, and the impact of polymer on downstream processing such as emulsions and heater tube fouling. The numerical reservoir simulation models have been history matched to both waterflooding and polymer flooding periods to conduct sensitivity studies of various parameters (injection rate, polymer retention, polymer concentration) to optimize the oil recovery beyond the pilot.

Results and Discussion

The primary objective of this paper is to summarize the current status of the polymer pilot and to demonstrate that the challenging Arctic environment is certainly not a barrier for the success of heavy oil polymer EOR. Accordingly, in the following sub-sections, key results and their discussion are presented. For specific details, the reader is referred to our topical publications on polymer retention (Wang et al., 2020); effect of water salinity (Zhao et al., 2020); conformance control (Zhao et al., 2021); oil-water separation (Chang et al., 2020); polymer induced fouling of heater tubes (Dhaliwal, 2021, Dhaliwal et al., 2020); and polymer injection performance (Ning et al., 2019, 2020).

Pilot Performance. Barring two operational events, polymer hydration issues, and a more recent drill-by of another producer (outside the pattern area) the polymer flood pilot has continued, almost seamlessly, as per the plan. Polymer QC to ensure full hydration is ascertained via the filter ratio (FR) criteria (Levitt and Pope, 2008). Typically, 250 cc of aqueous polymer solution is filtered through a 1.2 μ cellulose filter and the collection time of the filtered solution recorded at 60, 80,180 and 200 cc is used in the following equation, $FR = \frac{T_{200cc} - T_{180cc}}{T_{80cc} - T_{60cc}}$. Any values of FR < 1.2, passes the QC criteria. Other operational parameters such as polymer concentration and viscosity are closely monitored and adjusted. As shown in **Figure 1** the current polymer concentration is 1,200 ppm with a target viscosity of 30 cP at 7.3s^{-1}. The polymer injectivity is monitored and diagnosed by Hall plot (Hall, 1963) as shown in **Figure 2**, which graphs the integration of the differential pressure between the injector and the reservoir vs. cumulative polymer solution injection. The data would form a straight line if the injectivity stays constant over time, curve up if the injectivity decreases and vice versa. The injectivity of J-23A has been stable recently and the injectivity of J-24A increased after resuming injection in January, following the drill-by of another well outside the pattern. To date approximately 670,000 pounds of polymer have been injected into J-23A and the cumulative volume of polymer solution injected is 1.4 million barrels, whereas in J-24A it is 280,000 pounds of polymer and 0.6 million barrels of polymer solution, respectively. The 2 million barrels of polymer solution represents approximately 13% of the total pore volume of the flood pattern.

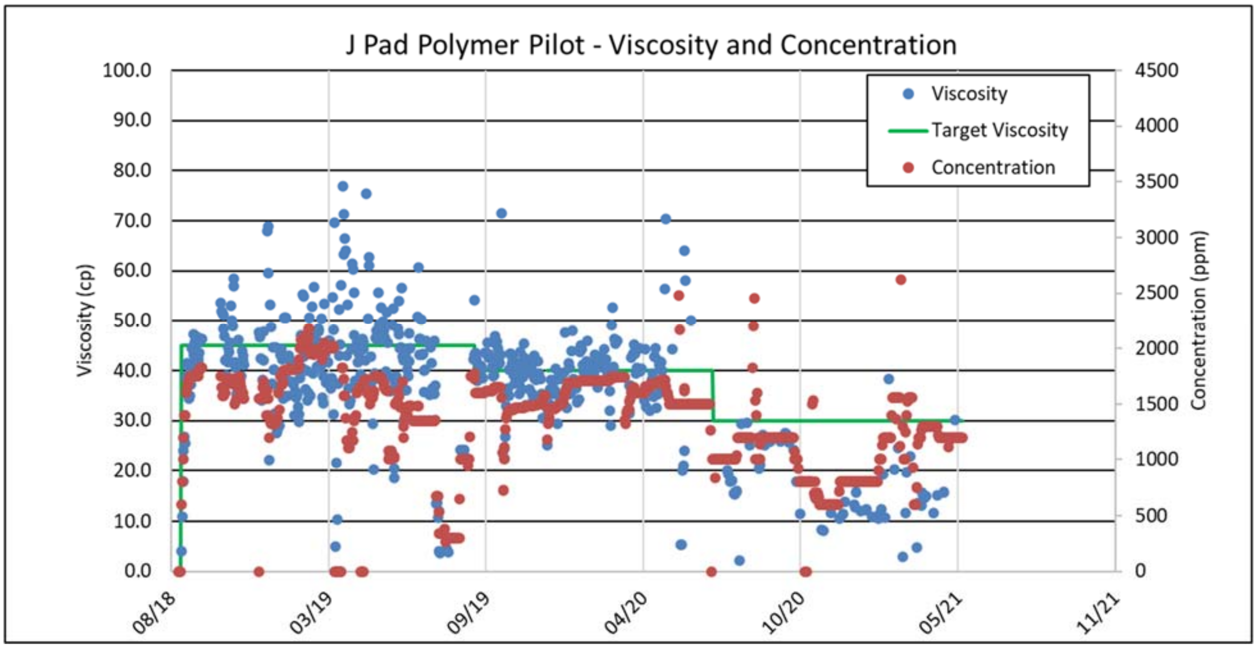

Figure 1. J-pad polymer solution concentration and viscosity vs. time.

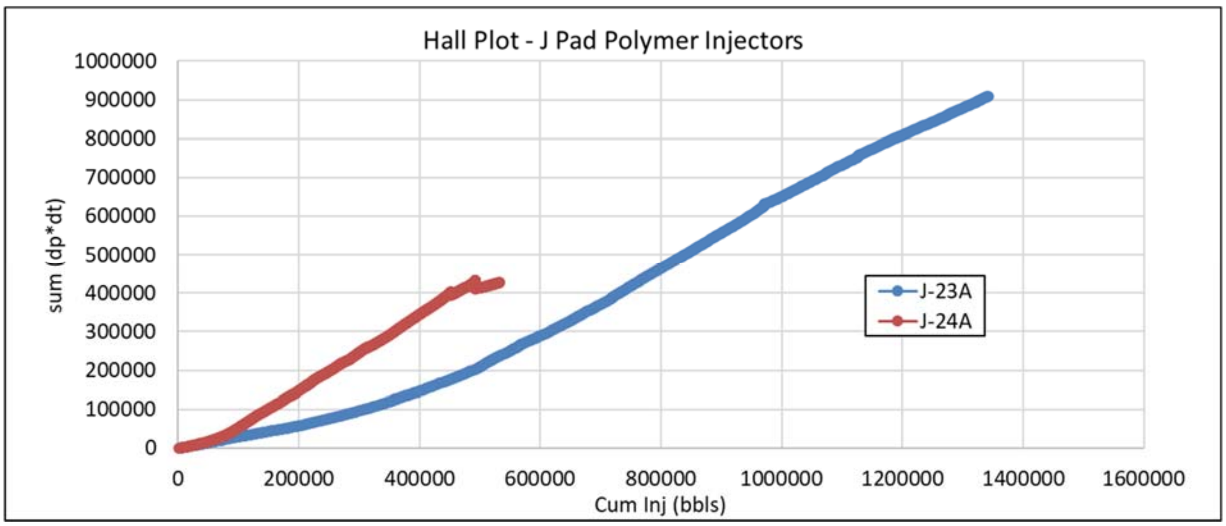

Figure 2. Hall plot of J-pad injectors.

Figure 3 and **4** depict the production performance of producers J-27 (supported by J-23A and J-24A) and J-28 (supported by J-23A from the North) respectively. In J-27 the oil rate was declining from late 2018 to late 2019 due to decreasing injection rate after polymer startup, but the water cut decreased dramatically due to the effect of polymer. Then the oil rate started to increase from late 2019 until early 2021 as the water cut decreased continuously. Current oil rate is approximately 800 bpd while the water cut is still very low (<10%). In J-28 water cut decreased from about 70% to less than 10% since the start of polymer injection. The fast response in water cut shortly after polymer startup is most likely caused by polymer blocking off the water fingers developed during the prior waterflood process. The water cut remained low from August 2019 to January 2021 although the well test data showed some fluctuations between September 2020 and January 2021. The oil rate increased from early 2019 to late 2019 and then stabilized at 500-700 bpd. Current oil rate is approximately 700 bpd with water cut of ~35%.

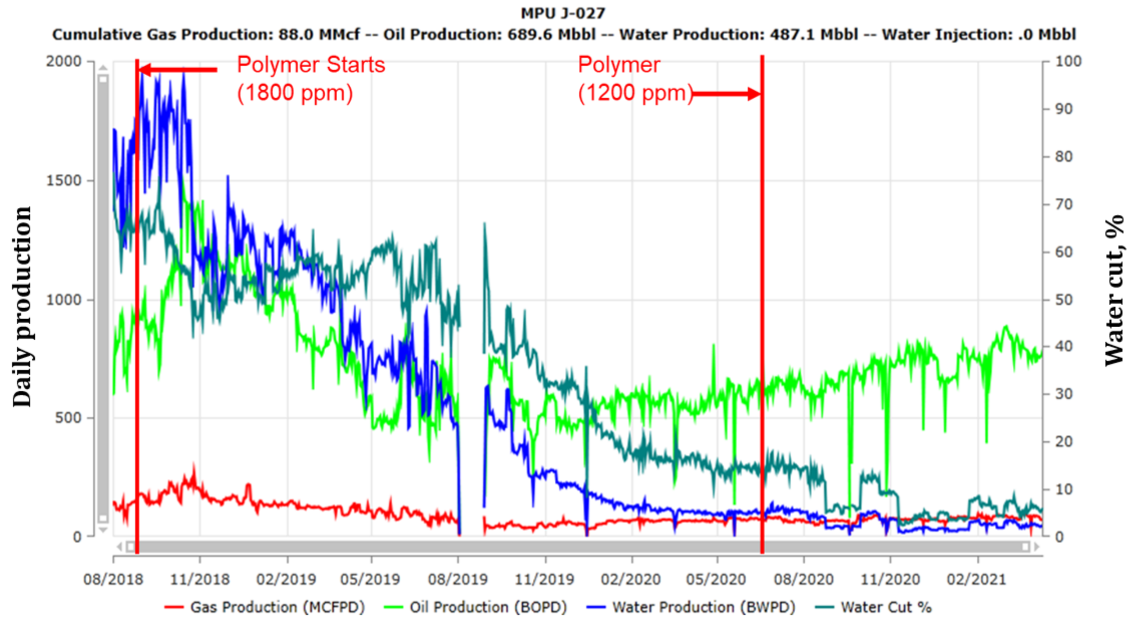

Figure 3. Performance of producer J-27.

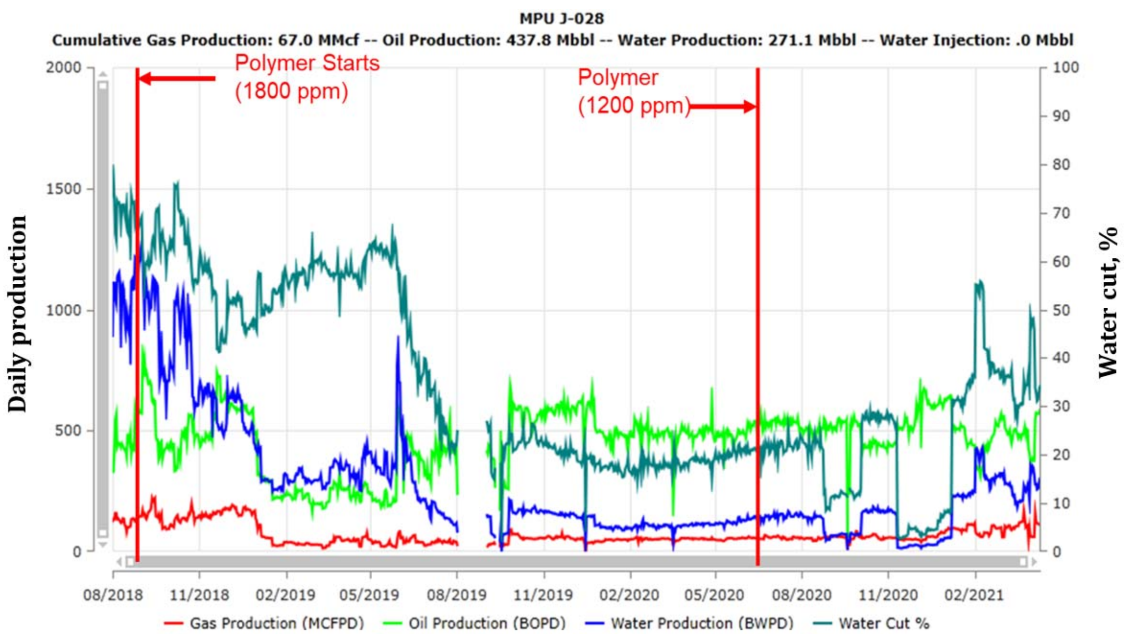

Figure 4. Performance of producer J-28.

Since the start of polymer injection, produced water samples have been collected bi-weekly when possible and analyzed onsite using the clay flocculation test, as well as in the laboratory via nitrogen-chemiluminescence water composition analyses to detect the presence of produced polymer in the production stream. Polymer production was first confirmed in the water sample collected on 10/10/2020 from producer J-27 with a polymer concentration of 197 ppm, while polymer was first seen from J-28 in the 12/13/2020 sample with a polymer concentration of 629 ppm. This means that polymer breakthrough time is approximately 26-28 months in the pilot patterns. Produced polymer concentrations are reported in **Table 1**.

Table 1. Produced HPAM concentrations (ppm).

Date	J-27	J-28
10/10/20	197	
~10/24/20	113	
~11/12/20	325	
12/13/20		629
12/27/20		634
1/24/21		762
2/10/21		659
2/22/21		736
3/8/21		752
3/8/21		790
4/25/21		906
5/4/21		904

Finally, the EOR benefits are graphically illustrated in **Figure 5**, which plots the actual oil production rate for the polymer flood compared with best case history matched oil rate had waterflood continued without polymer. The difference between the two curves which is ~1,000 bopd is deemed as EOR benefit. Another measure of success of the ongoing polymer pilot is the polymer utilization factor defined by the ratio of cumulative polymer injected and cumulative EOR produced oil, which is 950,000 lb/548,000 stb or 1.7 lb/stb. This value is less than half the reported "utility factor" of 3.9 lb/stb for a polymer pilot in Argentina (Juri et al., 2020) that uses the same polymer.

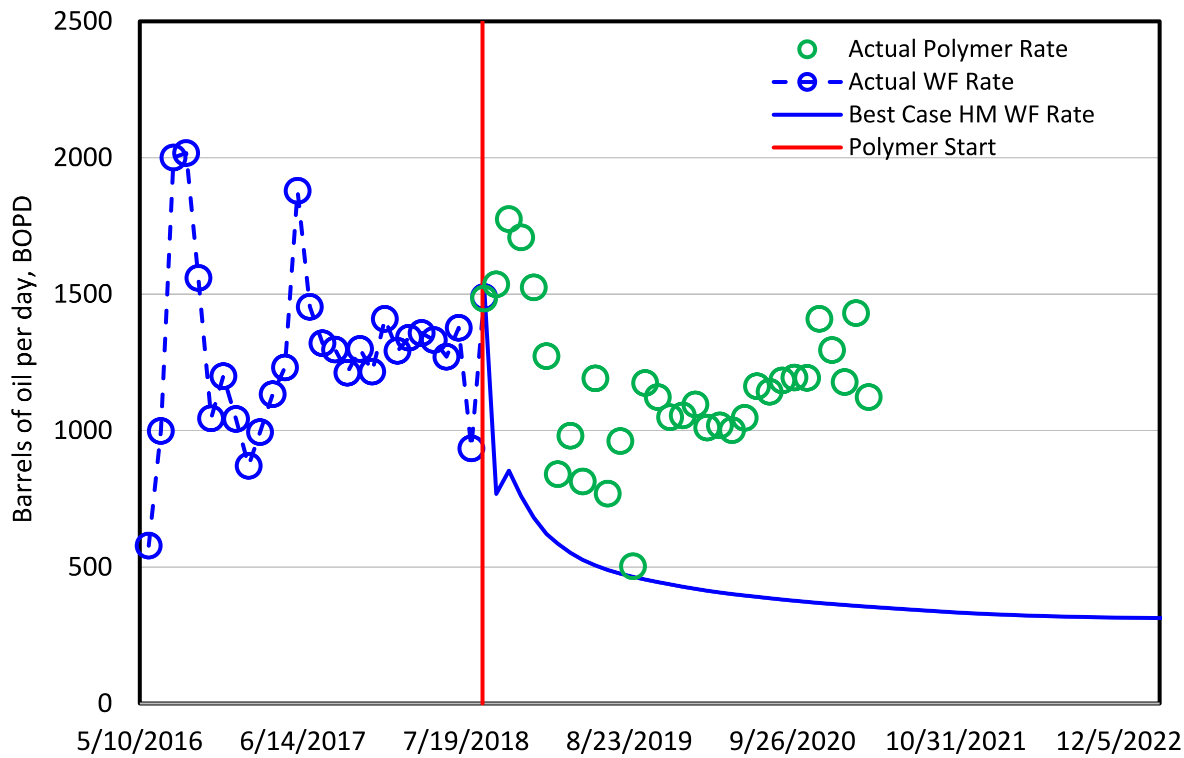

Figure 5. J-pad polymer benefit.

Polymer Retention. One of the determinants in any polymer flood is the retention of polymer expressed in µg/g of rock, due to entrapment and adsorption. Retention values are commonly measured by conducting corefloods in which the relative values of carbon and nitrogen (both part of the HPAM structure) vs. PV of polymer injected are tracked (Seright, 2017). As an example, a polymer retention curve that uses nitrogen chemiluminescence, for the subject set of rock and fluids and the polymer is shown in **Figure 6**. Many such polymer retention experiments have been conducted to date and the determined values are plotted against the absolute permeabilities for the three different sands in Milne, to discern trends. **Figure 7** suggests that the average value is fairly high (e.g., 217 µg/g as in **Figure 6**) for NB#1 sands. The obvious question is, what do such high retention values mean for the pilot? As demonstrated by the green curve in **Figure 6**, ~70% of the injected polymer propagates rapidly with *low retention* (note the earlier part ~1 PV and 0.7 relative effluent value), whereas the remaining 30% "tails" over many PVs. Thus, at least 70% of the polymer propagates without any holdup, whereas the remainder propagates at a rate perhaps too slowly to be of practical value. These observations were incorporated into our simulation effort—replacing the standard Langmuir isotherm for polymer retention.

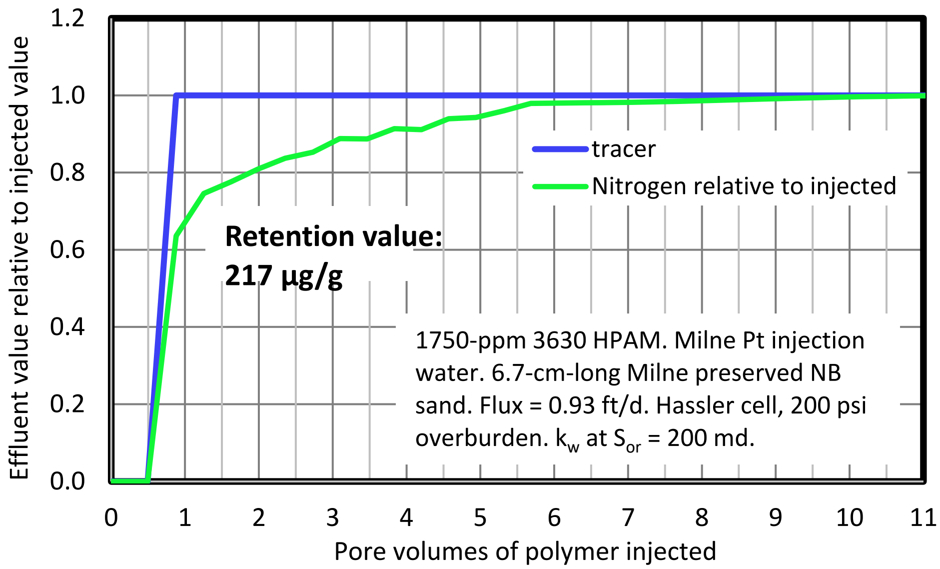

Figure 6. Polymer retention curve in one of the NB#1 sands showing the tailing effect.

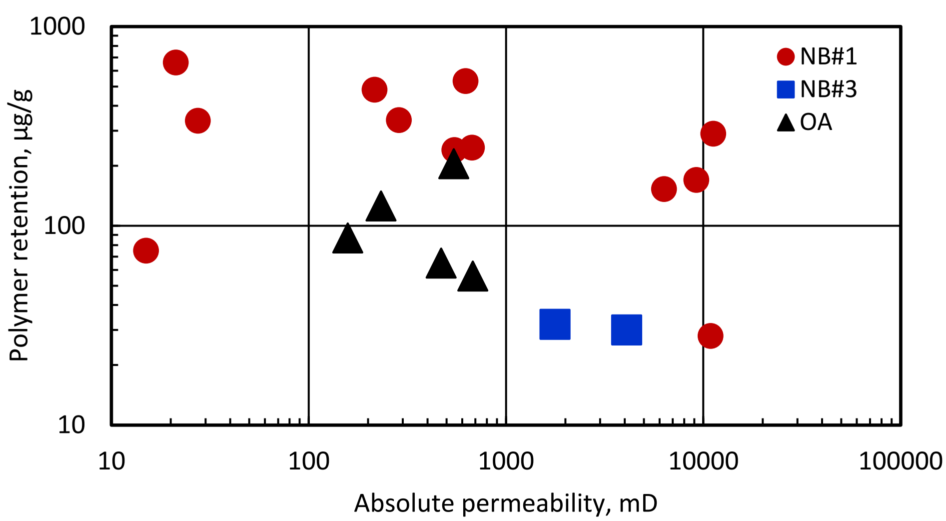

Figure 7. HPAM (3630S) polymer retention values vs. absolute permeability for various Schrader Bluff sandpacks.

Effect of Injection Water Salinity. The impact of injection water salinity on displacement and on the polymer solution (in terms of concentration and viscosity relationship) is also an important metric for the ongoing pilot. Low-salinity brine reduces the amount of polymer by more than one third than the normal brine with the same salinity of formation water to achieve the same target viscosity (Zhao et al. 2020). Accordingly, several coreflooding experiments were conducted to establish these trends. **Table 2** summarizes the incremental oil recovery performance of coreflooding experiments performed so far. In these experiments, 3-9% additional oil was recovered from tertiary low-salinity water flooding (Milne Pt. injection source brine) performed after high-salinity water flooding (Milne Pt. formation brine) using native NB sand (from the depth of 3,755 ft from Liviano-01A well). Also, extra oil was recovered from low-salinity polymer flooding (3630S, 45 cP) after high-salinity polymer flooding with the same viscosity. In contrast, no additional oil was recovered from the low-salinity polymer flooding when 173 cP mineral oil was used as the oil phase. The results thus suggest that the low-salinity benefit is related to the properties of oil.

Table 2. Summary of oil recovery performance.

Sand	Conditions	No. of tests	Incremental recovery, % OIIP			
			LSW after HSW	HSP after HSW/LSW	LSP after HSW/LSW	LSP after HSP
Silica sand	Old SIB=4945 ppm (still termed as LSW) kw=50-1400 mD	7	1-6	4-5	8-12	No tests in this way
NB sandpack	From well Liviano-01A Depth: 3755' Used in native status Kw=200-16,000 md	10 (four failed due to low Kw)	***3-9***	5-8	10.6 (one test)	***3-9***
NB sandpack (cleaned)	From well Liviano-01A Depth: 3755' Cleaned with solvent; Use mineral oil (173 cP) to establish Swi	1	No tests in this way	13 (one test)	No tests in this way	0.7 (one test)
NB core plug (cleaned)	From well Liviano-01A Depth: 3760' Label: core 3-7 Received from Weatherford in cleaned condition	4 (three failed due to low Kw or crush of core plugs)	No tests in this way	No tests in this way	9.1 (one test)	No tests in this way

Numerical Reservoir Simulation. The primary goal is to first history match the prior waterflood data and the incoming polymer flood data to create a robust reservoir simulation model capable of testing sensitivities to parameters such as polymer concentration, retention, injection rates and forecast oil recovery over a prolonged period. Accordingly, a layer cake reservoir simulation model of the flood pattern has been constructed based on the geology, seismic data, well logs, core data as well as wellbore trajectories and configurations. As shown in **Figure 8**, the model includes features such as high permeability strips to represent high permeable channels or zones that may exist in the reservoir since the formation is unconsolidated.

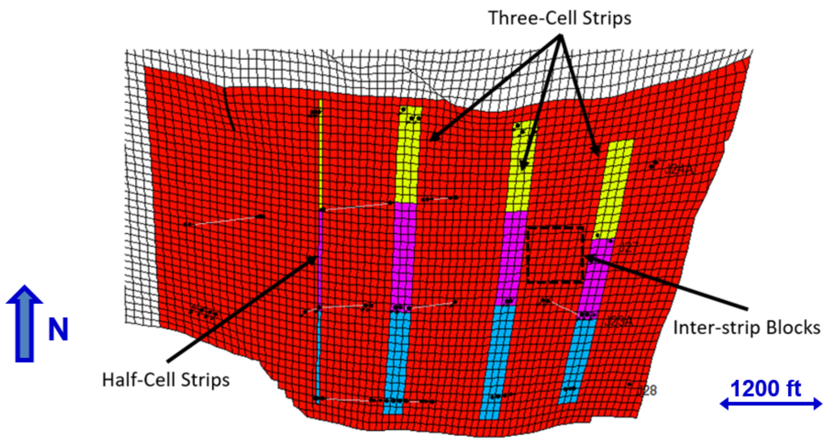

Figure 8. Static layer cake model with high transmissibility strips.

During the history matching process, the transmissibilities of high-permeability strips remain fixed values from the beginning of waterflooding. Then the transmissibilities are tuned with polymer injection time to improve the history matching results in the polymer flooding period. By collecting new production data, the production history used to modify the reservoir simulation model is continually updated. The water injection rate and oil production rate are set as well constraints in the reservoir simulation model. An example of the history matching results of water cut for J-28 are presented in **Figure 9**. The open circles are actual production data and the solid lines are history matching results. It can be seen that the sharp increases of water cut after water breakthrough has been well reproduced by employing the high transmissibility strips in the reservoir simulation model. In the polymer flooding period, the history matching results show that the simulated water cut agrees with the field observations and achieve the extremely low water cuts, which was particularly challenging in the beginning.

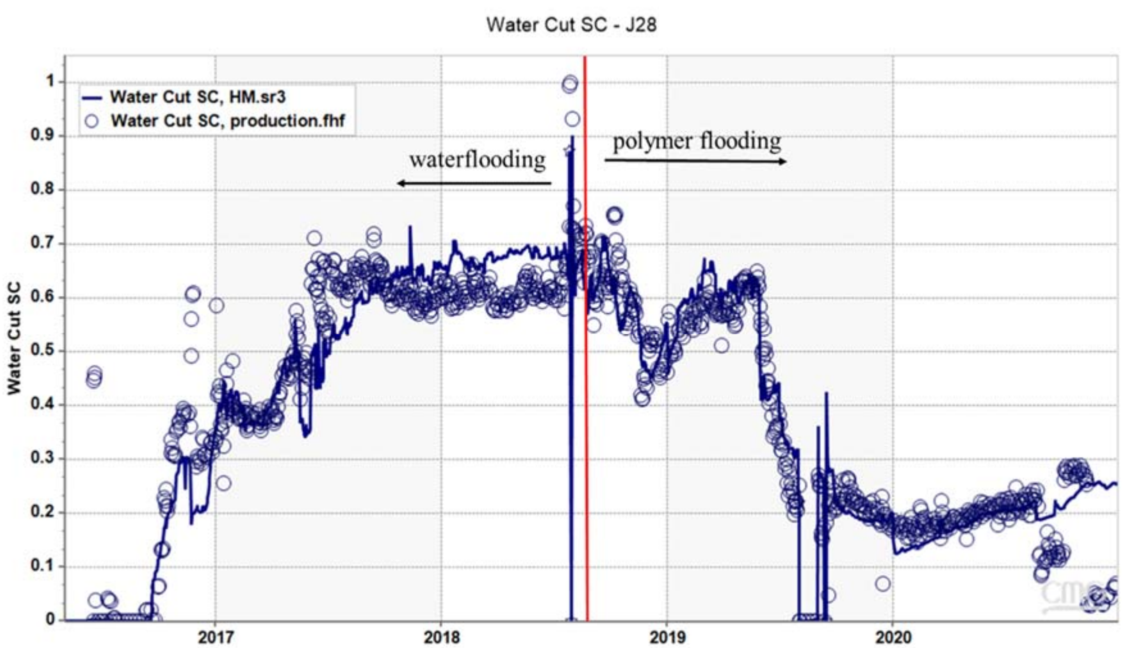

Figure 9. History matching results of water cut for producer J-28.

The aforementioned history matched model has been used to conduct the sensitivity analysis with respect to the oil recovery factor. In the concentration sensitivity simulations, polymer retention of 153 µg/g, and the total injection rate of 1,950 bbls/day are fixed, whereas in the retention sensitivity simulations, the polymer concentration (and rate) is fixed at 1,200 ppm. The combined sensitivity analysis for reservoir simulations with the polymer concentrations ranging from 900 to 2,700 ppm and polymer retention ranging from 50 to 400 µg/g are presented in **Figure 10**. Clearly, without compromising significantly on oil recovery, reduced polymer concentration is cost effective and promotes injectivity, whereas oil recovery is inversely proportional to polymer retention (as expected). Perhaps the optimum polymer concentration lies in the vicinity of 1,200-1,500 ppm which will be determined by further refining the reservoir simulation model and the ongoing economic analysis.

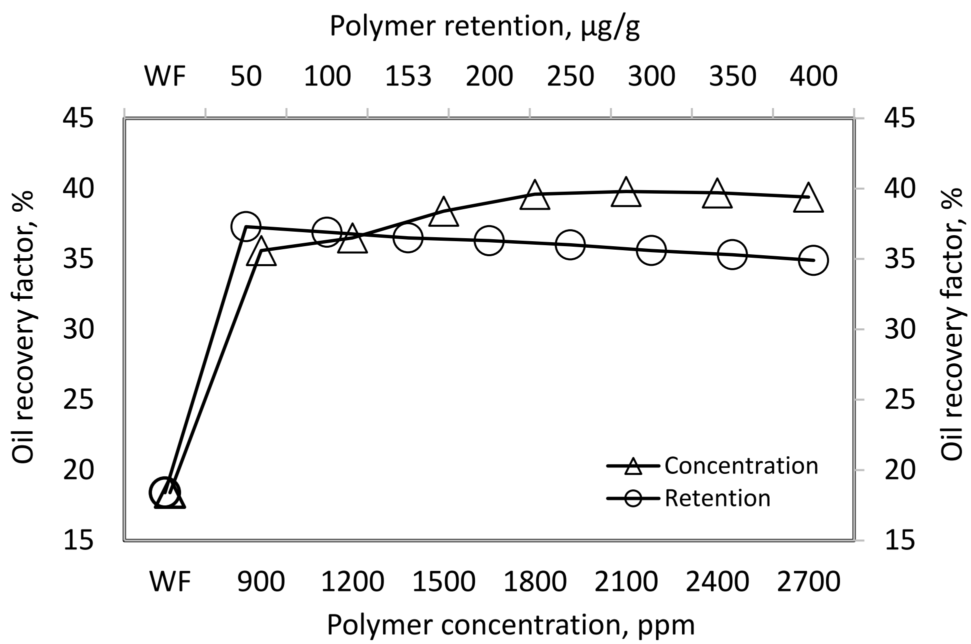

Figure 10. Influence of polymer concentration and retention on oil recovery. Note: WF means waterflood, which has been used in the J-pad polymer benefit plot in Figure 5.

Impact of Produced Polymer on Emulsions and Heater-Treater Tube Fouling. One of the major concerns from a downstream flow assurance standpoint is the potentially negative impact of the produced polymer (after the breakthrough) on oil-water separation, vis-à-vis emulsions and fouling of heater-treater tubes. Both of these have been extensively experimented for screening suitable composite emulsion breakers and heater skin temperature operating conditions. While we continue to broaden the scope of some of these experiments, selected results on emulsion and fouling tests are presented here.

Electrical submersible pumps (ESPs) are used in both J-27 and J-28 to lift the produced fluids as a means of artificial lift; however, this comes with a drawback, in that the pump impeller rotates at a high speed potentially promoting (tight) oil-water emulsions. The function of any emulsion breaker, is to break the emulsion and separate the oil and water to produce sales-quality oil and disposal-spec-water respectively. In our studies on testing the efficacy of emulsion breakers the action of an ESP is mimicked by an equivalent rotational speed in a laboratory scale mixer to generate emulsions of oil, water and polymer at different water cuts and polymer concentrations. These emulsions are subsequently subjected to a “bottle test” and/or “turbiscan” after the emulsion breaker to be tested is added in various dosages and its performance measured via factors such as speed of separation, water clarity, basic sediment and water (BS&W) in oil and separation efficiency. **Figure 11** shows the BS&W and oil content as a function of concentration for the composite (E12+E18) emulsion breaker that we have screened as the best performer. Additional interfacial and rheological investigations being conducted also confirm the superior performance of the composite emulsion breaker.

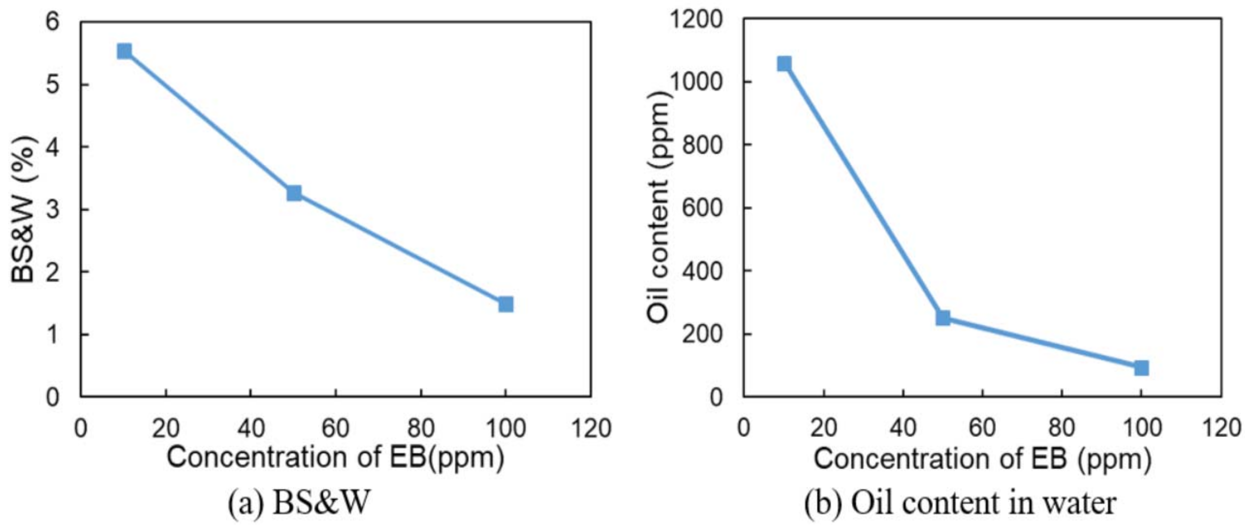

Figure 11. Demulsification performance of composite (E12+E18) emulsion breaker for emulsion with 800 ppm polymer at 75% water cut.

The primary purpose of the heater-treater system on Milne is to aid the separation of oil and water by increasing the phase density difference. In principle, somewhat analogous to the ESPs, the use of heaters also comes with a bit of disadvantage, in that the high temperature being conducive to polymer (and potentially mineral) fouling of the heater tubes, thus reducing the overall heat transfer coefficient. We have conducted fouling tests to evaluate the fouling potential for heater tubes that are in contact with the process fluid (a mixture of produced oil and water, potentially containing polymer after breakthrough). Fouling of both the outside as well as inside the heater tubes is studied for different metallurgies and heating skin temperatures. Outside tests are static and provide the deposit rate, whereas, inside tests are dynamic (flow experiments) and result in pressure drop (differential pressure) increases due to blocking of the tube(s). **Figure 12** shows the results of the deposit tests for copper, carbon steel and stainless steel.

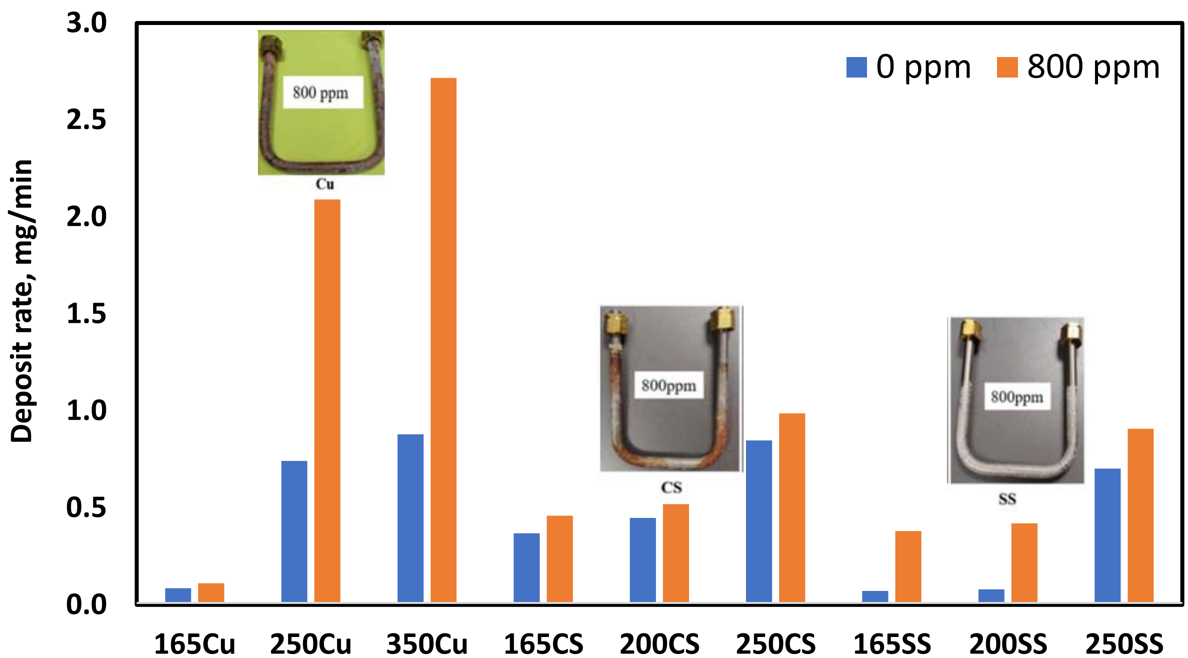

Figure 12. Deposit rates for copper (Cu), carbon steel (CS) and stainless steel (SS) at tested temperatures, with (800ppm) and without polymer (0ppm).

In dynamic tests the two primary parameters that influence fouling are tube velocity and the residence time. Clearly, both cannot be concurrently satisfied in any lab scale flow loop; however, we believe that residence time is the most critical and a rigorous parameter to match with field conditions. **Figure 13** plots the differential pressure vs. test or flow duration at the four tested temperatures. In all the tests the tube material is stainless steel and the polymer concentration is 400 ppm.

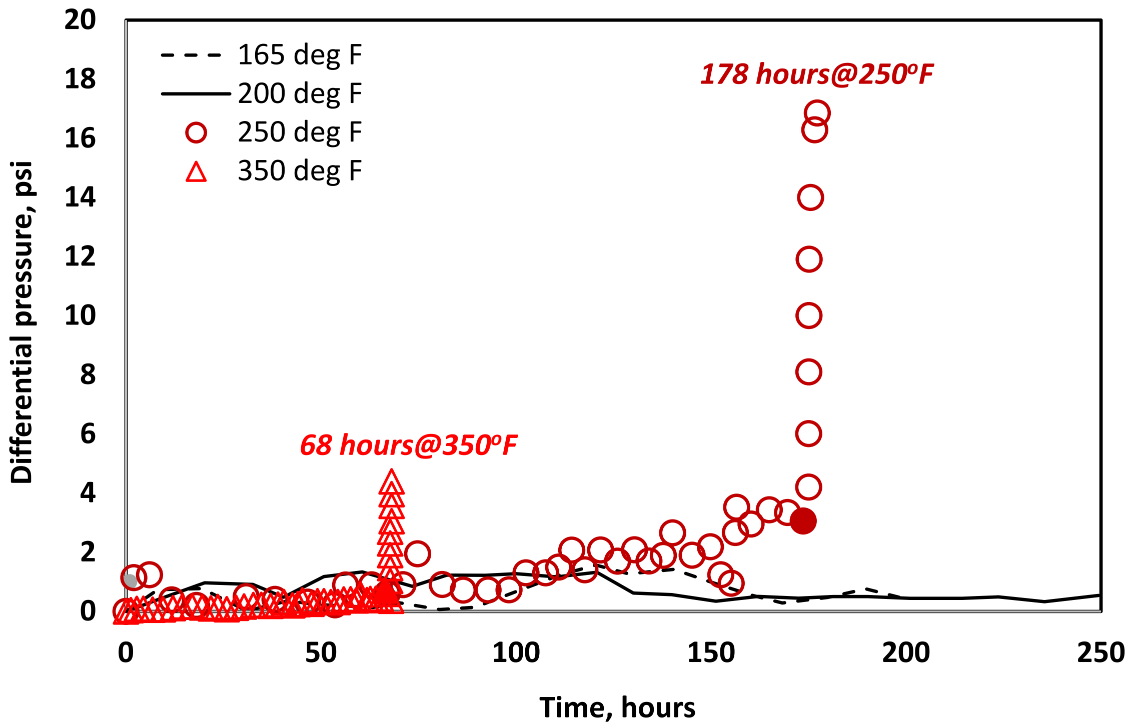

Figure 13. Differential pressure vs. test or flow time in the dynamic scale loop experiments conducted in stainless steel tubes at a polymer concentration of 400 ppm.

As seen in the plot, the pressure drops vs. test or flow time at 165 °F and 200°F is flat indicating that at these temperatures, basically there appears to be no blocking vis-à-vis fouling. However, the notable spikes in the pressure drop at 250°F and 350°F clearly demonstrate blockage due to fouling; note that this occurs much earlier, i.e., 68 hours@350°F, compared with 178 hours@250°F. Our polymer solution cloud points (not reported here; see Dhaliwal, 2021, Dhaliwal et al., 2020) and associated phase change measurements corroborate the static and dynamic fouling data.

Conclusions

Based on the performance of the polymer pilot and the associated research conducted so far, the following main conclusions are drawn:

First and foremost, with more than 2.5 years of nearly seamless polymer injection, performance of the two producers, and low polymer utilization factor amply demonstrates the success of the polymer pilot in the Alaskan arctic.

Although polymer retention values are relatively high, the first 70% of the polymer concentration/viscosity propagates well at Milne and is of practical importance rather than the delayed 30% retention tail.

In displacement experiments performed on core material saturated with representative oil, we consistently observe low salinity benefits of reducing residual oil saturation, and improving oil recovery. From the economic point of view, low-salinity makeup brine can significantly reduce the amount of polymer than the normal brine with the same salinity of formation water to achieve the same target viscosity.

A reliable history match has been achieved for the waterflooding as well as the exceptionally low water cut in the polymer flooding periods respectively. The history matched reservoir simulation model has been successfully tested in sensitivity and forecasting.

Flow assurance experiments have screened a composite emulsion breaker and identified safer operating skin temperatures in the heater-treater system.

Nomenclature

ANS	Alaska North Slope
bbl	Barrel
bopd	Barrels Oil per Day
bpd	Barrels Per Day
BS&W	Basic Sediment & Water
BWPD	Barrels of Water Per Day
cp or cP	Centipoise
CS	Carbon Steel
EOR	Enhanced Oil Recovery
ESP	Electrical Submersible Pump
FR	Filter Ratio
HM	History Match
HPAM	Hydrolyzed polyacrylamide
HSP	High Salinity Polymer
HSW	High Salinity Water
k or K	Permeability
lb	Pound mass
LSP	Low Salinity Polymer
LSW	Low Salinity Water
MCFPD	Thousand Cubic Feet Per Day
md or mD	Millidarcy
mg	Milligram
MMP	Minimum Miscibility Pressure
MPU	Milne Point Unit
OIIP	Oil Initially in Place
OOIP	Original Oil in Place
ppm	Parts Per Million
PV	Pore Volume
QC	Quality Control
SC	Standard Conditions
SIB	Synthetic Injection Brine
SS	Stainless Steel
stb	Stock Tank Barrel
S_{wi}	Irreducible Water Saturation
TDS	Total Dissolved Solids
µg	Microgram
WC	Water cut

Acknowledgments

"This material is based upon work supported by the Department of Energy, Office of Fossil Energy, administered by the National Energy Technology Laboratory, under Award Number DE-FE0031606." Disclaimer: "This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

The authors also would like to thank Hilcorp Alaska, LLC for cosponsoring this project. We especially thank the engineers and operators (Jeremy Alcord, Cody Barber, Aaron Barlow, Brock Birkholz, Kyler Dunford, Kade Foust, David Haakinson, James McKenna, Joel Milette, Doyle Miller, Connor Redwine, Jerry Stinson, Gabriel Toci, Ryan Traxler, and Will West) of Hilcorp's North Slope Team for their tremendous efforts to ensure smooth operations for this field pilot and all our graduate students (Hongli Chang, Anshul Dhaliwal, Cody Keith, Jianqiao Leng, Chunxiao Li, Shane Namie, Xindan Wang, and Yang Zhao) and technicians for their diligent work in running lab experiments and computer models.

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