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Abhijit Dandekar

Baojun Bai
Missouri University of Science and Technology, baib@mst.edu

John Barnes

Dave Cercone

et. al. For a complete list of authors, see https://scholarsmine.mst.edu/geosci_geo_peteng_facwork/2177

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The Success Story of First Ever Polymer Flood Field Pilot to Enhance the Recovery of Heavy Oils on Alaska's North Slope

Abhijit Dandekar, University of Alaska Fairbanks; Baojun Bai, Missouri University of Science and Technology; John Barnes, Hilcorp Alaska LLC; Dave Cercone, DOE-National Energy Technology Laboratory; Reid Edwards, Hilcorp Alaska LLC; Samson Ning, Reservoir Experts, LLC/Hilcorp Alaska, LLC; Randy Seright, New Mexico Institute of Mining and Technology; Brent Sheets, University of Alaska Fairbanks; Dongmei Wang, University of North Dakota; Yin Zhang, University of Alaska Fairbanks

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Abstract

The primary goal of the first ever polymer flood field pilot at Milne Point is to validate the use of polymers for heavy oil Enhanced Oil Recovery (EOR) on Alaska North Slope (ANS). The specific objectives are systematic evaluation of advanced technology that integrates polymer flooding, low salinity water flooding, horizontal wells, and numerical simulation based on polymer flood performance data. Accordingly, under the co-sponsorship of the US Department of Energy and Hilcorp Alaska LLC the first ever polymer field pilot commenced on August 28, 2018 in the Schrader Bluff heavy oil reservoir at the Milne Point Unit (MPU) on ANS. 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 J-pad flood pattern. Since July 2020, HPAM concentration was reduced to 1,200 ppm to control injectivity and optimize polymer utilization. Filter ratio tests conducted on site ensure uniform polymer solution properties. Injectivity is assessed by Hall plots, whereas production is monitored via oil and water rates from the two producers. Water samples are analyzed to determine the produced polymer concentration. Supporting laboratory corefloods on polymer retention, injection water salinity, polymer loading, and their combinations on oil recovery, match rock, fluid and test conditions. A calibrated and validated numerical multiphase reservoir model was developed for long-term reservoir performance prediction and for evaluating the project's economic performance in conjunction with an economic model. Concerns related to handling of produced fluids containing polymer are addressed by specialized experiments.

As would be expected in a field experiment of this scale, barring some operational and hydration issues, continuous polymer injection has been achieved. As of September 30, 2022, a total of 1.41 million lbs of polymer or 2.99 million bbls of polymer solution (~18.8% of total pore volume), placed in the pattern serves as an effective indicator of polymer injectivity. During the first half of the pilot period, water cut (WC) drastically reduced in both producers and over the entire duration, the deemed EOR benefit over waterflood was in the range of 700-1,000 bopd, and that too at a low polymer utilization of 1.7 lbs/bbl. Low

concentration polymer breakthrough was observed after 26-28 months, which is now stabilized at 600–800 ppm in congruence with the WC. Although as indicated by laboratory experiments, polymer retention in core material is high; ~70% of the injected polymer propagates without any delay, while the remaining 30% tails over several PVs. History matched simulation models consistently forecasts polymer recovery of 1.5–2 times that of waterflood, and when integrated with the economic modeling tool, establish the economic profitability of the first ever polymer flood field pilot. Produced fluid experiments provide operational guidance for treating emulsions and heater-treater operating temperature.

Over a duration of ~4.5 years important outstanding technical issues that entail polymer flooding of heavy oils have been resolved, which forms the basis of the success story summarized in the paper. The first ever polymer pilot is deemed as a technical and economic success in significantly improving the heavy oil recovery on ANS. The pilot has provided impetus to not only apply polymer EOR throughout the Milne Point Field, but has paved the way for additional state-funded research targeting even heavier oils on the ANS. The combined success of this work and the future work will contribute to the longevity of the Trans Alaska Pipeline System (TAPS).

Introduction

Alaska's high viscosity oil resources that range between 20–30+ billion barrels represent about a third of known North Slope original oil in place (OOIP). These resources are primarily concentrated in the Schrader Bluff Formation (also called West Sak on the Western North Slope) and Ugnu reservoirs and are categorized as "viscous oils" and "heavy oils" owing to their in-situ viscosities between 5–10,000 cP and up to a million + cP respectively. The viscous oil deposits are relatively deeper (2,000 – 5,000 ft), whereas the heavy oils are somewhat shallower (2,000 – 4,000 ft). The typically shallow depths and the proximity to the continuous permafrost results in relatively lower formation temperatures and pressures, and consequently higher viscosities. The vertical depth vs. viscosity delineated in Paskvan et al. (2016) differentiates the viscous and heavy oils. As depicted in Paskvan et al. (2016), currently the main focus (referred to as "developing") is on the viscous oils in the Schrader Bluff Formation in the MPU. Notwithstanding this Alaska North Slope (ANS) specific categorization, we use the industry adopted, all-inclusive term "heavy oil" for all high viscosity oils. Resource characterization and additional details can be found in topical publications of Paskvan et al. (2016) and Targac et al. (2005).

Despite the vast resource base, the development pace, vis-à-vis the production of heavy oils has been very slow and limited due to multiple factors such as cost, logistics, challenging arctic environment, poor waterflood sweep efficiency due to mobility contrasts, and significantly high minimum miscibility pressures (MMP). Most importantly, typical or standard thermal methods that are commonplace elsewhere (Canada, California) are inapplicable due to the continuous permafrost. As a consequence, cumulative production of heavy and viscous oils is a little over 1% of OOIP slope wide and currently, there is hardly any production from Ugnu. However, on a broader level, these unfavorable factors are outweighed by the fact that (1) these resources, within the established infrastructure, are too large to ignore because of their strategic importance to the Nation and the State of Alaska and (2) Prudhoe Bay type "light" diluent crude oil is still available to facilitate the transport of heavy oil through the TAPS. Similarly, from a reservoir standpoint, the following factors also are important positive offsets: (1) favorable rock characteristics of Schrader Bluff; (2) the promise demonstrated by the initial scoping studies (Seright 2010, 2011) suggesting significant increase of heavy oil recovery using polymer flooding; (3) successful field implementation in Canada, China and elsewhere in the world, and (4) availability of the existing pairs of horizontal injector-producer in Schrader Bluff pattern.

The foregoing was recognized as 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 scale experiment to test the polymer flooding technology to unlock the vast heavy oil resources on ANS. With this primary goal in mind, the research team embarked on a ~4.5 years long project that focused on the field polymer pilot complemented by supporting laboratory and simulation studies. Over the course of the project, many lessons have been learned and valuable field and supporting laboratory data has been collected, which also is complemented by numerical reservoir simulations. We have been able to establish the injectivity of polymer solution, evidence of significant reduction in the WC of previously waterflooded pattern, effective propagation of HPAM, benefits of low salinity water, provide practical guidance on handling of produced fluids containing breakthrough polymer, fit-for-purpose forecast-worthy history matched simulation model, polymer EOR benefit of 700-1,000 bopd over waterflood, a low polymer utilization factor of ~1.7 lbs/bbl, and most importantly the economic profitability. Herein lies the purpose of this paper.

Summary of Polymer Field Pilot and Supporting Activities

In a number of our previous publications (Dandekar et al., 2019, 2020, 2021, Ning et al., 2019, 2020) the polymer field pilot area and test wells have been adequately described; therefore, only a summary is included here for completeness. The pilot started in a fault block in the J-pad of the Milne Point Unit, which consists of two horizontal injectors and producers, namely J-23A, J-24A and J-27, J-28 respectively. The horizontal sections range in lengths from 4,200 to 5,500 ft whereas the inter-well distance varies between 1,100 and 1,500 ft, respectively. Both injector-producer pairs were drilled into the Schrader Bluff NB-sand and the pattern was employed for a waterflood that lasted for ~2 years prior to the commencement of the pilot. The waterflood was terminated when the oil recovery was merely 7.6% and water cut had reached 70%, which was one of the motivating factors for the polymer pilot. The injection of polymer is accomplished via an injection unit which was custom designed and manufactured for this project for operations in the Arctic environment. The hydrolyzed polyacrylamide or HPAM (Flopaam 3630S) polymer powder is mixed with (low salinity) water to prepare a mother solution, which is subsequently diluted according to the desired injection concentration. The initial polymer concentration was 1,750 ppm, which was reduced stepwise to 1,500 and later to 1,200 ppm (current concentration). The water used for making polymer solution is produced from a source water well (J-02) completed in the Prince Creek Formation overlying the Ugnu Formation which contains relatively fresh water supply with total dissolved solids of 2,600 milligrams per liter and total hardness of 280 milligrams per liter. In order to avoid shearing of the polymer, positive displacement pumps are used for injection.

Given the fact that a pilot of this scale cannot be conducted in isolation, laboratory activities and numerical simulation carried out in parallel complement and support the polymer field pilot. These range from the 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-treater tube fouling. The numerical reservoir simulation models have been iteratively 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. The base-matched Full Model polymer forecast also was subjected to an economic parameter sensitivity test that included the oil price; polymer cost and the facilities cost.

Results and Discussion

The primary objective of this paper is to document the success of the first ever polymer flood field pilot to enhance the recovery of heavy oils on Alaska's North Slope. Accordingly, this section summarizes the key results and discusses the main findings of practical significance. For extensive specific details, the reader is referred to our following topical publications, namely polymer retention (Seright and Wang, 2022); effect of water salinity (Zhao et al., 2021); conformance control (Zhao and Bai 2022); emulsions and oil-water separation (Chang et al., 2022 and 2020); polymer induced fouling of heater tubes (Dhaliwal et al., 2022 and 2021); polymer injection performance (Ning et al., 2020 and 2019); and numerical reservoir simulation/ history matching and economic analysis (Wang et al., 2021 and Keith et al., 2022).

Polymer Field Pilot Performance.

As would be expected in a field pilot of this scale, barring some operational events, continuous polymer injection in the pattern has been successfully achieved, which continues to this date. As of September 30, 2022, a total of 1,410,625 lbs of polymer had been injected into the two injectors and the total amount of polymer solution injected was 2.99 million barrels (~18.8% of the total pore volume in the 2 flood patterns). Figure 1 shows the history of polymer concentration and viscosity with a current target viscosity of 30 cP.

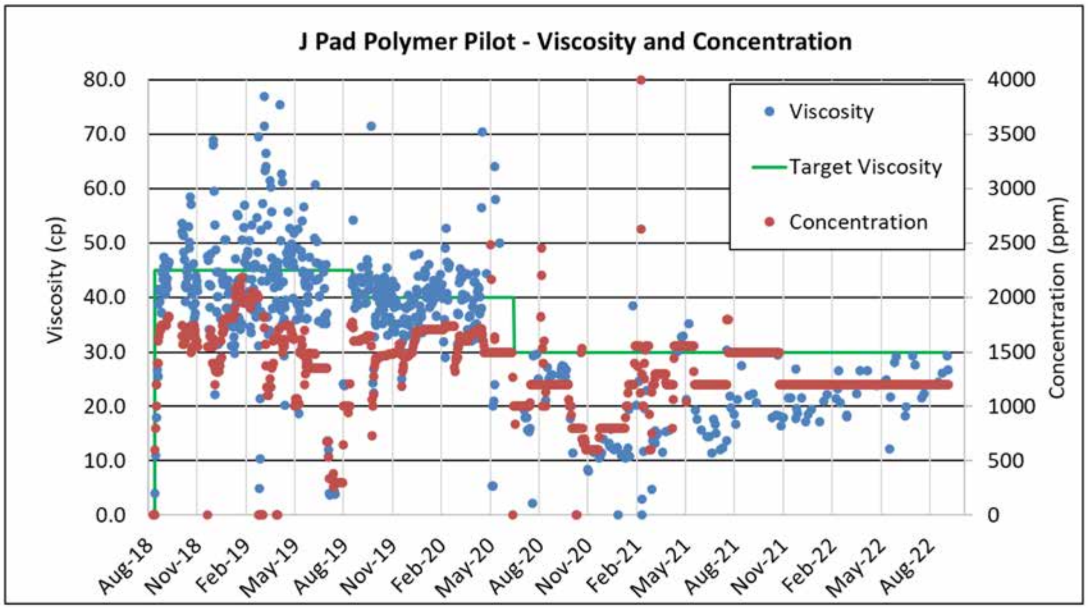

Figure 1—Polymer concentration and viscosity vs. time.

The performance of the injectors J-23A and J-24A is depicted in Figure 2 via a Hall plot (Hall, 1963) which plots the integration of the differential pressure between the injector and the reservoir versus cumulative water injection. The data would form a straight line if the injectivity stays constant over time, curve up if the injectivity decreases and vice versa. As seen in Figure 2, during the early times, injectivity of both injectors was decreasing (until about March 2019) due to the high polymer viscosity as well as some poorly mixed polymer. After some improvements on the polymer injection unit (PIU), the injectivity stabilized for about 2 years followed by an increase which was likely due to polymer breakthrough (October, December 2020) combined with the decrease in polymer viscosity. During the last year of the pilot (October 2021 through the end of September 2022), the injectivity of both injectors stabilized again.

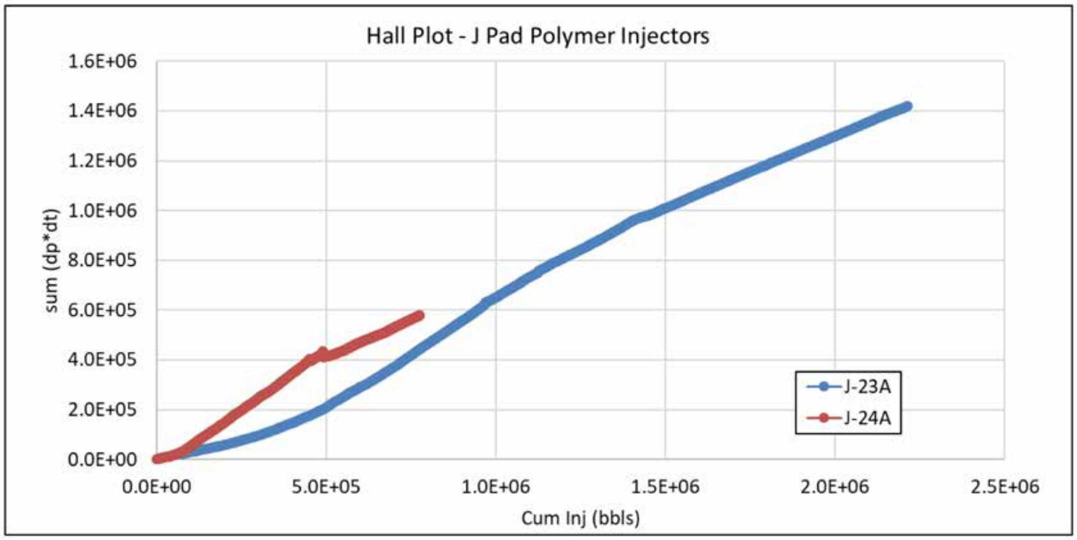

Figure 2—Hall plot of J-pad injectors.

A side by side comparison of the two pilot producers, namely J-27 and J-28, is shown in Figure 3. Note that producer J-27 is supported by both injectors; J-23A from the South and J-24A from the North, whereas producer J-28 is supported only by J-23A from the North since the south side is adjacent to a sealing fault. The main highlight of both producers is the (similar) water cut (WC) performance in that the WCs dropped from ~70% during waterflooding before the pilot to less than 10% during polymer injection. To the best of our knowledge, no other field polymer flood has resulted in this magnitude of reduction in WC. The sharp drops in the oil rates in both producers are attributed to operational events and the spike in WC in J-27 (circa fall 2022) is likely caused by measurement errors since the jet pump (replaced the failed ESP) uses water as a power fluid. The oil rates and WCs in J-27 and J-28 have somewhat stabilized at 600 bpd, 360 bpd and 50%, 70% respectively.

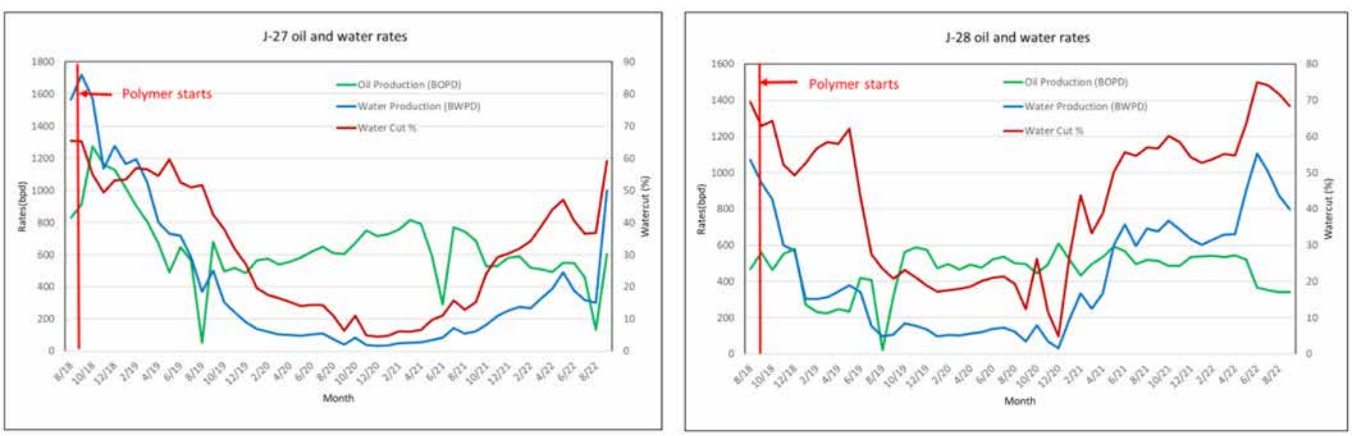

Figure 3—Performance of the J-pad producers.

Produced water samples have been collected bi-weekly when possible and analyzed onsite and in the lab via N_2-chemiluminescence to detect the presence of produced polymer in the production stream. Polymer breakthrough (BT) was first detected in J-27 in an October 2020 sample and J-28 later, which means that polymer BT time is ~ 26-28 months in the pilot patterns (see Figure 4).

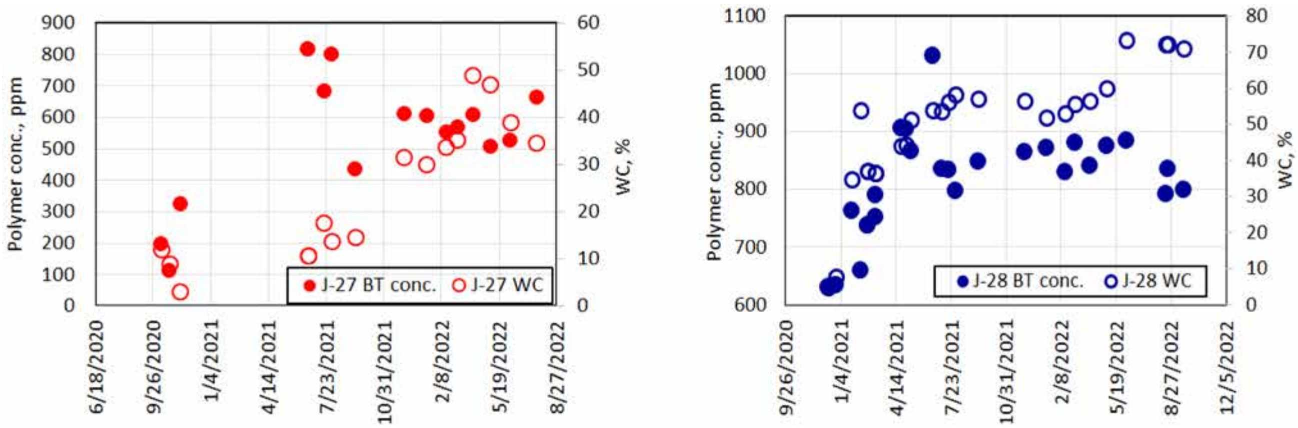

Figure 4—Polymer breakthrough concentration and WC in J-27 and J-28.

Figure 5 plots the actual oil production rate with polymer flood compared with predicted oil rate had waterflood continued without polymer. The predicted oil rate is using the best case waterflood history matched model. Note the very low actual polymer flood oil rate (circa August 2019), which is the period when operational issues related to polymer hydration were being diagnosed while injecting straight water or low concentration polymer (a little over a month). The difference between the two curves is deemed as EOR benefit. Current oil rate is approximately 950 bpd from the two producers and the predicted oil rate without polymer injection is about 250 bpd, giving an estimated EOR benefit of ~700 bopd. During the pilot period, oil rate increased by 700-1,000 bpd over predicted waterflooding rate. Polymer flooding more than tripled oil rate compared with waterflooding alone.

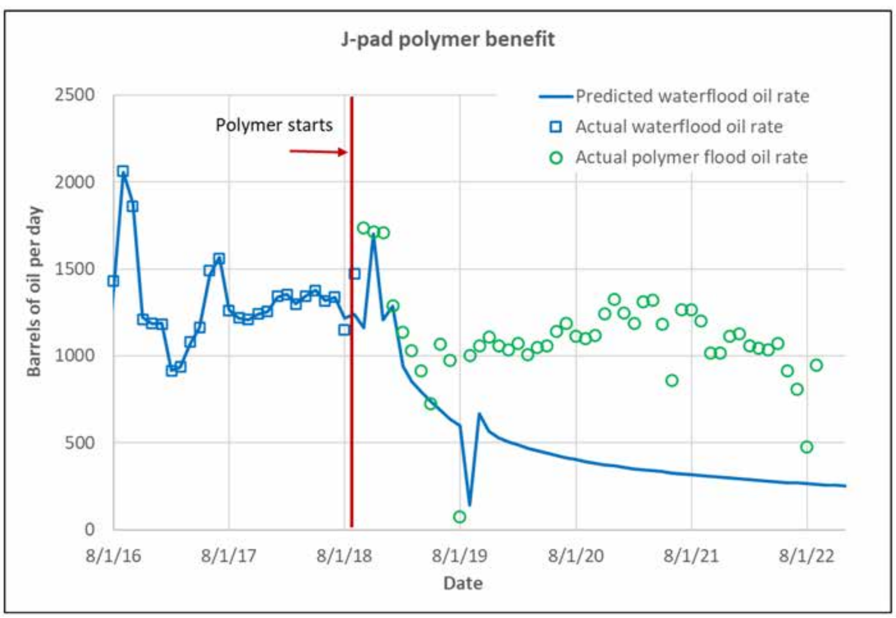

Figure 5—Incremental oil rate over waterflood.

Polymer Retention and Tailing.

Retention (e.g., adsorption, mechanical entrapment) is a significant parameter that may directly impact the effectiveness of a polymer flood. In support of the pilot activities, many polymer retention experiments have been conducted. As shown (Figure 6) by the results from one such experiment, although retention is high, ~70% of the injected polymer propagates rapidly with low retention (~1 PV and 0.7 relative effluent value), whereas the remaining 30% slowly "tails" over many PVs. This tailing behavior yields overall retention up to 600 μg/g, even though most polymer is not delayed.

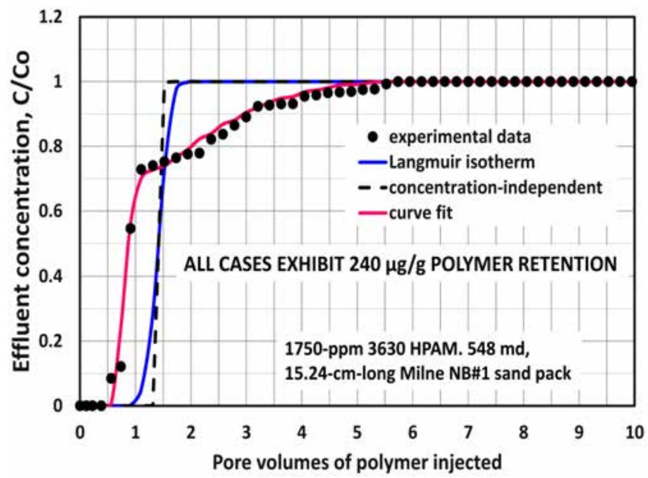

Figure 6—Tailing phenomenon observed during a polymer retention study.

To understand the origin and significance of this peculiarity many polymer retention sensitivity experiments have been conducted to determine the influence of every conceivable rock and fluid parameter. These suite of experiments revealed that illite (dominant clay present in the formation) is primarily responsible for the tailing phenomenon and the divalent cations accentuate HPAM retention (see Figure 7), whereas all the other parameters are deemed as insensitive to polymer retention.

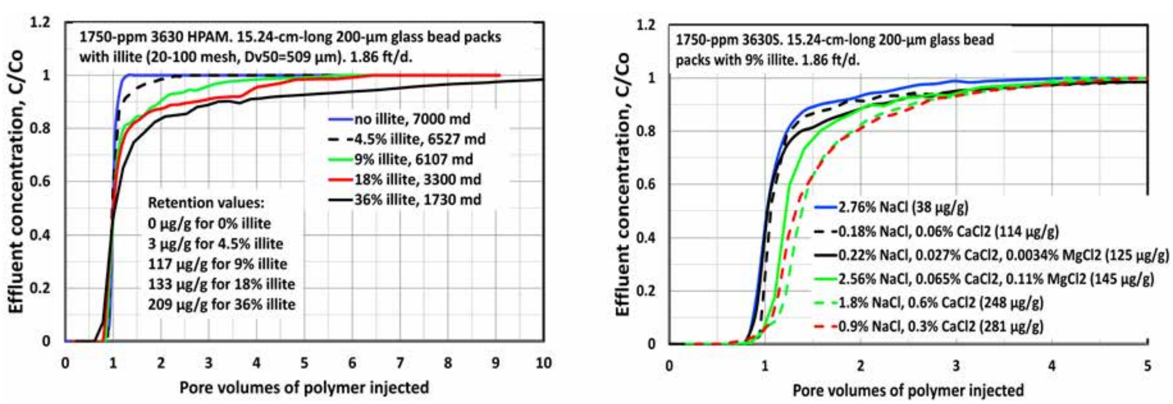

Figure 7—Significant influence of illite and divalent cations on HPAM retention and tailing.

Injection Water Salinity and Polymer Synergistic Effects.

Similar to the polymer retention experiments, numerous corefloods were carried out to examine the effect of water salinity and polymer solutions made with different salinities on oil recovery. In all the tests low salinity benefits were consistently observed as shown in Figure 8. For example, 45 cP polymer solution viscosity at 7.3 s^{-1} is obtained at a polymer concentration of 1,400 ppm by using low salinity synthetic injection brine (SIB) as opposed to 2,300 ppm synthetic high salinity formation brine (SFB), which is basically a saving of 1/3rd of the polymer when low salinity makeup water is used. The influence of low salinity alone as well as the synergistic effect with the polymer is shown in the right most plot in Figure 8; increment in the oil recovery by using low salinity water (LSW) after high salinity water (HSW) and additional oil recovered by the polymer solution prepared with LSW (marked as LSP).

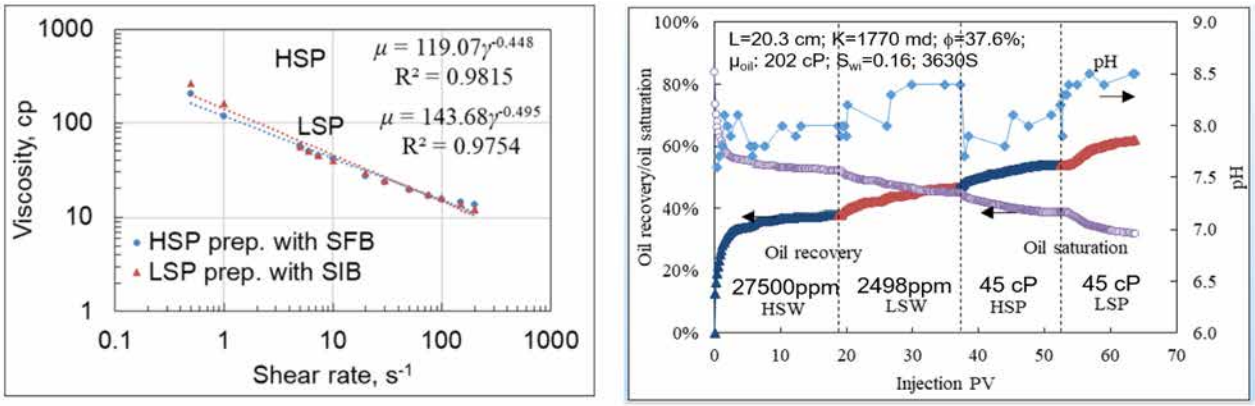

Figure 8—Positive effects of low salinity on polymer loading and oil recovery.

Strategies for Conformance Control.

The focus of other supporting corefloods (not shown here but discussion included for demonstrating the completeness of the pilot design) on artificially created heterogeneous porous media was for screening and evaluation of preformed particle gels (PPG) for conformance control. The main goal was to test if the displacing fluid can be diverted toward the low permeability zones and recover additional oil. Accordingly, gel treatment design plan based on the injection profile of injector J-23A was prepared and kept on standby for deployment in case producer WCs exceeded 80% (as decided by the pilot team). However, as seen in Figure 3 WCs in both J-27 and J-28 are still well below the 80% threshold, thus precluding the need for conformance control at the present time.

Reservoir Simulation of Pilot Pattern.

The primary aim of the reservoir simulation model was to obtain a reliable history match (HM) of the WC in both producers for forecast and economic analysis. Figure 9 shows the static layer cake model (and the evolution with time) of the pilot pattern constructed based on the geology, seismic data, well logs, core data as well as wellbore trajectories and configurations. In order to improve the HM, twelve high permeable channels/zones running through all layers are introduced to address unconsolidation and/ or viscous fingering.

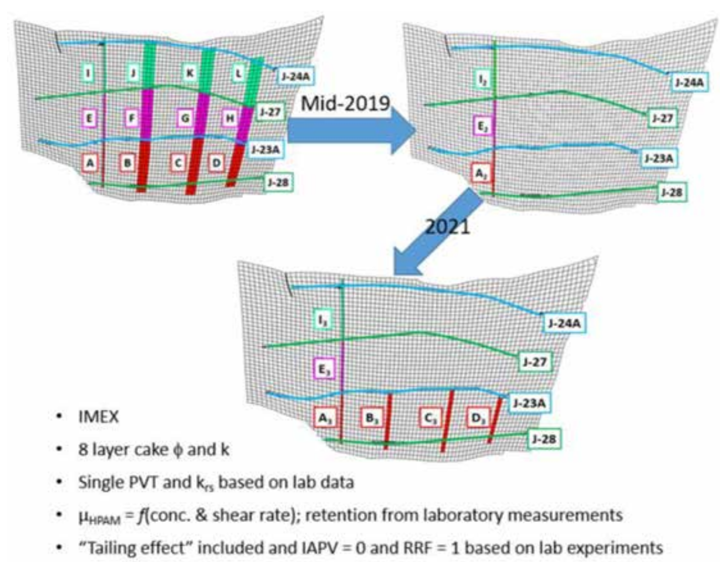

Figure 9—Temporal evolution of static layer cake model of the pilot pattern, Keith (2022).

Simulated water cut results for both producing wells for three different history matched models and a base model are shown in Figure 10. Clearly, the base model is totally inadequate in capturing the high and the low WCs during the waterflood and the polymer flood, respectively. This necessitated a different step-wise HM approach that involved the strip transmissibility (multipliers), thus resulting in basically three different history matched models, namely the Full Model, Model A, and Model B (for details see Keith, 2022).

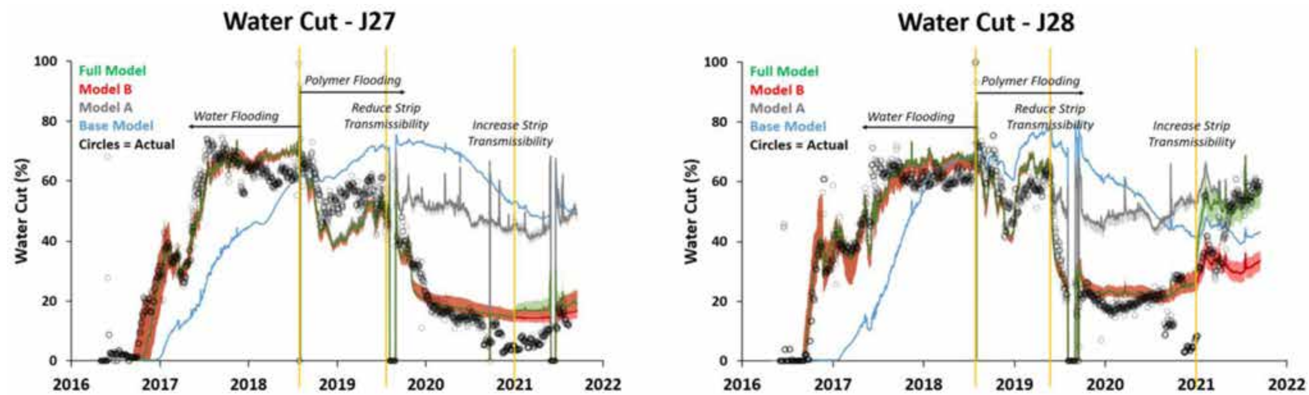

Figure 10—Water cut simulation results for J-pad producers, Keith (2022).

The oil recovery forecasts produced by the three models and waterflooding alone are compared in Figure 11. As can be seen, Model A and Model B produce the most pessimistic and optimistic results, respectively, whereas the Full Model predicts an intermediate oil recovery. However, most importantly, all three history matched models predict significantly higher oil production under polymer flooding compared to waterflooding alone.

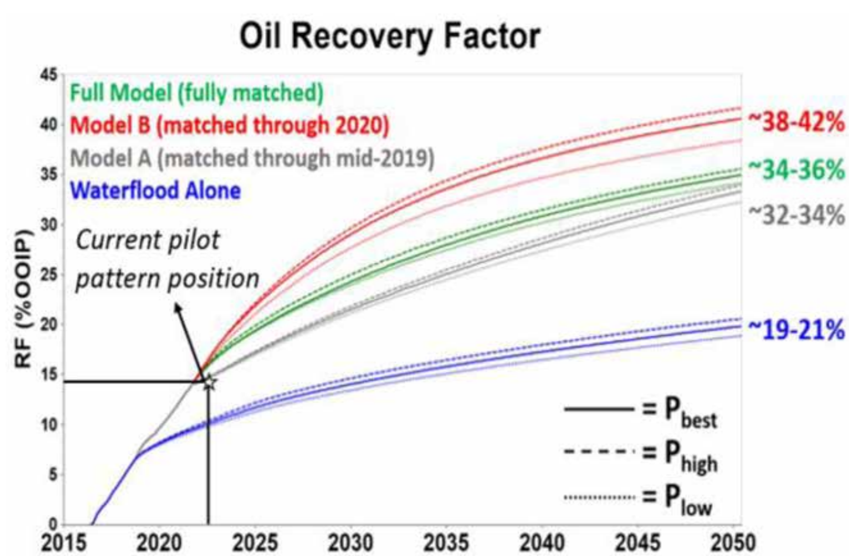

Figure 11—Predicted oil recovery for each forecasted simulation case.

Handling of Produced Fluids – Emulsions and Heater Treater-Tube Fouling.

The two major produced polymer concerns, namely influence on emulsions and heater-treater tube fouling were addressed using elaborate parametric and mechanistic experimentation. We have extensively documented the experimental procedures and the analysis of the results in screening the requisite emulsion breakers and heater-treater operating temperature in our topical publications (Chang et al., 2022 and 2020; Dhaliwal et al., 2022 and 2021). Therefore, key results are summarized in this section.

Lab formed emulsions (at different WCs, HPAM concentrations, and emulsion breaker dosages) that mimic the action of ESPs used in both producers were subjected to bottle tests and turbiscans to evaluate the efficacy of individual as well as composite emulsion breakers and additives. The screening criteria for demulsification included performance indicators such as BS&W and oil in water (OIW). As an example, Figure 12 shows the performance of various demulsifiers, their blends and additives for an emulsion containing illite (dominant clay in the formation) and sheared (because of ESPs) HPAM. Clearly, without any emulsion breaker, both the BS&W as well as OIW are the highest. Although the performance varies per the dosage and the type of emulsion breaker, these tests enable us to identify the best performing or optimum emulsion breaker blend, additive and the dosages, whereby we can leverage individual chemistries. For the data shown in Figure 12, the combination of E12+E18 and KCl (last two bars) becomes the most applicable demulsifier formula to treat the emulsion containing both polymer and clay particles.

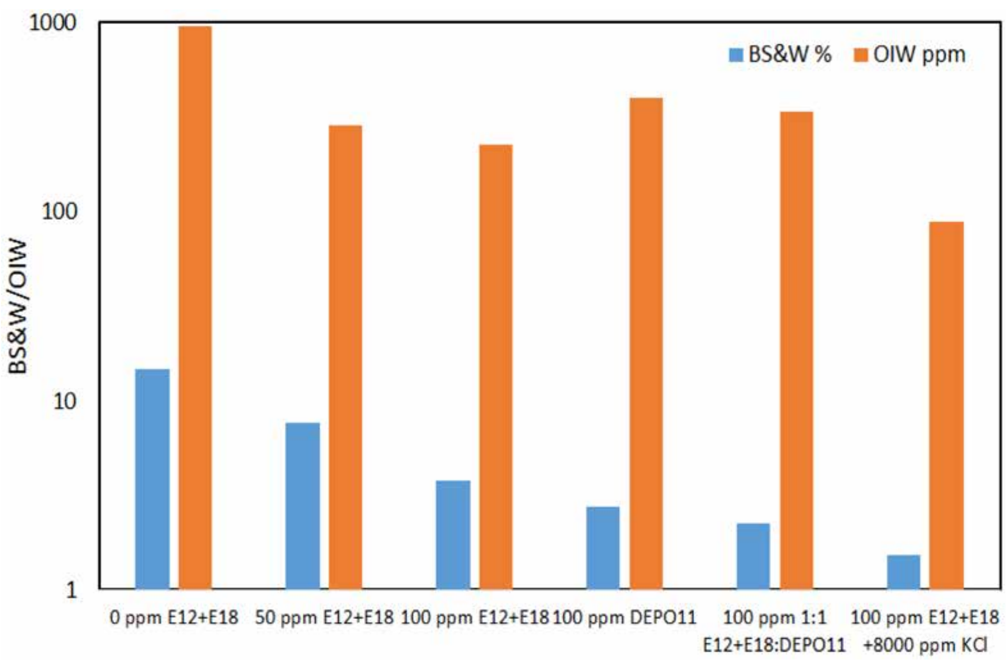

Figure 12—Performance of various demulsifiers for emulsion stabilized by 0.25wt% illite in the presence of 800 ppm sheared HPAM.

To understand the heater-treater fouling, mainly three different types of experiments were conducted; namely, cloud point of polymer solutions, static deposition tests on copper, carbon steel and stainless steel at various temperatures and dynamic or flow loop tests in stainless steel at field residence times. The primary goal of these experiments was to assess the impact of breakthrough polymer (fouling) in the production stream on the overall heat transfer coefficient. Figure 13 portrays the ensemble of the main results that show cloud point temperature, deposit rates and the pressure drop spikes, respectively. These experiments provide a clear operational guideline, in that at normal throughput rates in heater-treaters at Milne Point central processing facility the polymer fouling problem can be avoided by keeping the skin temperature below 250°F.

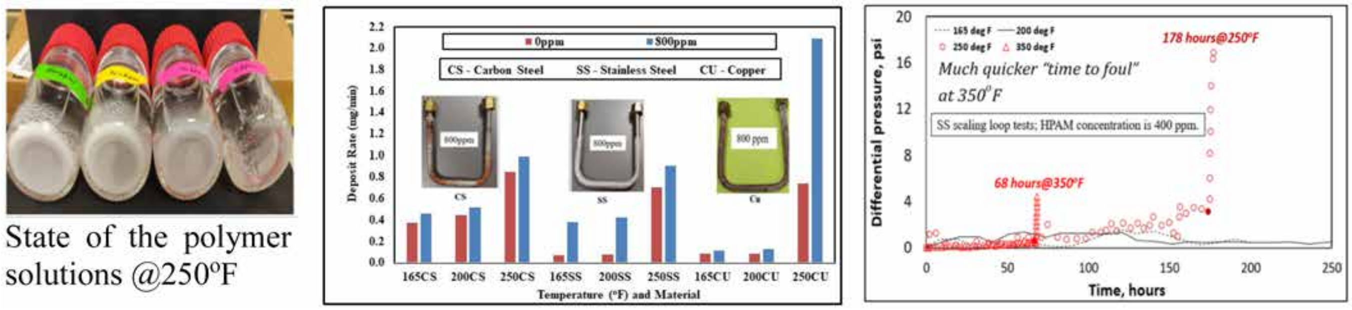

Figure 13—Ensemble of heater-treater polymer induced fouling experiments.

Economic Analysis of the Pilot.

As seen in Figure 11, we have demonstrated that polymer flooding is indeed technically feasible to significantly improve the heavy oil recovery on Alaska North Slope. However, the economic performance of the pilot, critical to determining its success, is another key metric used in assessing the overall performance of the field pilot. In one of our recent papers (Keith et al., 2022) we have extensively covered the economic evaluation of the polymer pilot. Therefore, only the main message is summarized here so as to conclude the success story of the first ever polymer pilot on ANS. The aforementioned three different history matched models were employed in the economic analysis of polymer flooding incremental to waterflooding. Note that each of these three models had three different cases of (1) best history-matched model (P_{best}); (2) most optimistic (P_{high}) and (3) most pessimistic (P_{low}). The "best-matched Full Model", which is intermediate between Model A and B, respectively, was used as a base case in the economic and design sensitivity analysis to provide recommendations for continued operation of the ongoing field pilot and future polymer flood designs.

Figure 14 serves as a ready reckoner of economic performance, in that Model A produces the most pessimistic results, Model B is the most optimistic, and the Full Model is intermediate. Note that a higher Net Present Value (NPV) indicates a greater project value while a higher discounted Profit to Investment (PI) ratio and low development cost indicate a more efficient investment. The best-matched Full Model simulation predicts that the polymer flood pilot will generate a present value of about \$42.9 million during the whole project life. In addition, each dollar invested yields \$5.05, and each barrel of oil produced over the project duration costs about \$8.35 to produce.

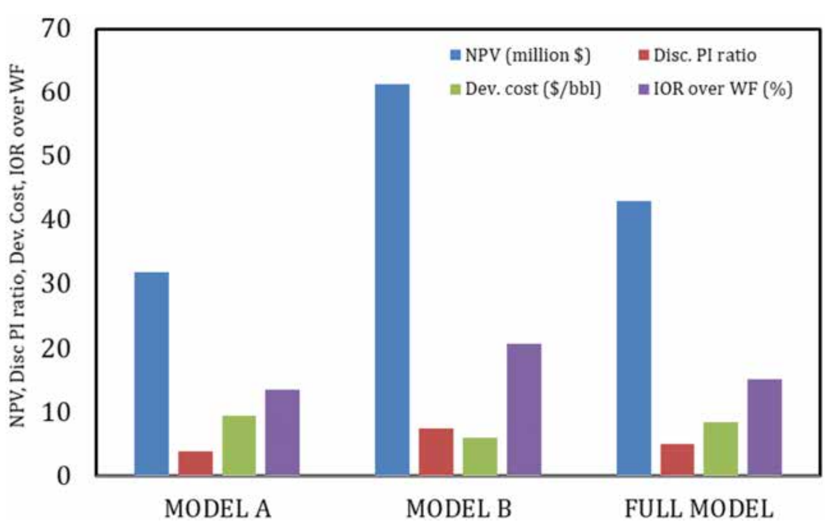

Figure 14—Comparison of economic performance of polymer flooding incremental to waterflooding for the three history matched models (data shown is for P_{best}; P_{low} and P_{high} and are tabulated in Keith et al., 2022).

Conclusions

Based on the successful conclusion of the polymer pilot and the associated research conducted, the following main conclusions are drawn:

- First and foremost, nearly seamless polymer injection in the Schrader Bluff heavy oil reservoir, drastic reduction in the WC from ~70% to less than 10% one year after polymer startup, and performance of the two producers in tripling the oil rate compared with waterflooding alone at a cumulative polymer utilization of 1.7 lbs of polymer/bbl of incremental oil produced amply demonstrate the success of the first ever polymer pilot on ANS.
- From a practical viewpoint, the observed tailing behavior means that retention causes no significant delay in propagation of the polymer bank (and therefore the oil bank), but the effective viscosity and displacement efficiency is less than originally planned.
- In displacement experiments performed on core material saturated with representative oil, we consistently observe improvement in oil recovery. Additional benefit of low salinity is also realized from the economic viewpoint; in that it can result in significant savings in the amount of polymer needed to achieve the same target viscosity.
- All calibrated simulation models predict significantly higher oil recovery from polymer flooding compared to waterflooding alone.
- A simulation model calibrated for waterflooding may not accurately capture the full benefit of an EOR strategy such as polymer flooding.
- One single emulsion breaker chemistry is inadequate in treating heavy oil emulsions, thus necessitating a combination with another emulsion breaker, and possibly an additive.
- HPAM hydrolyzes at high temperatures and precipitates with divalent cations, thus with normal throughput rates in heater-treaters at Milne Point, this problem can be avoided by keeping the skin temperature < 250°F.
- The first ever polymer flood field pilot to enhance the recovery of heavy oils is economically beneficial, with all calibrated simulation models remaining robustly profitable in a range of conservative economic scenarios.

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Nomenclature

ANS	Alaska North Slope
bbl	Barrel
bopd	Barrels Oil per Day
bpd	Barrels Per Day
BS&W	Basic Sediment & Water

BT	Breakthrough
BWPD	Barrels of Water Per Day
cp or cP	Centipoise
Cu	Copper
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
md or mD	Millidarcy
mg	Milligram
MMP	Minimum Miscibility Pressure
MPU	Milne Point Unit
NPV	Net Present Value
OIIP	Oil Initially in Place
OOIP	Original Oil in Place
OIW	Oil in Water
PI	Profit to Investment
PIU	Polymer Injection Unit
PPG	Preformed Particle Gel
ppm	Parts Per Million
PV	Pore Volume
QC	Quality Control
SC	Standard Conditions
SFB	Synthetic Formation Brine
SIB	Synthetic Injection Brine
SS	Stainless Steel
stb	Stock Tank Barrel
S_{wi}	Irreducible Water Saturation
TAPS	Trans Alaska Pipeline System
TDS	Total Dissolved Solids
µg	Microgram
WC	Water cut

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