TECHNICAL AND ECONOMIC EVALUATION OF THE FIRST EVER POLYMER FLOOD FIELD PILOT TO ENHANCE THE RECOVERY OF HEAVY OILS ON ALASKA’S NORTH SLOPE VIA MACHINE ASSISTED RESERVOIR SIMULATION

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ABSTRACT

Polymer flooding has become globally established as a potential enhanced oil recovery method for heavy oils. To determine whether this technology may be useful in developing the substantial heavy oil resources on the Alaska North Slope, a polymer flood field pilot commenced at the Milne Point Unit in August 2018. This study seeks to evaluate the results of the field pilot on a technical and economic basis. A reservoir simulation model is constructed and calibrated to predict the oil recovery performance of the pilot through machine-assisted reservoir simulation techniques. To replicate the early water breakthrough observed during waterflooding, transmissibility contrasts are introduced into the simulation model, forcing viscous fingering effects. In the ensuing polymer flood, these transmissibility contrasts are reduced to replicate the restoration of injection conformance during polymer flooding. Transmissibility contrasts are later reinstated to replicate fracture overextension interpreted in one of the producing wells. The calibrated simulation models produced at each stage of the history matching process are used to forecast oil recovery. These forecasts are used as input for economic analysis, incremental to waterflooding expectations. The simulation forecasts indicate that polymer flooding significantly increases the heavy oil production for this field pilot compared to waterflooding alone, yielding attractive project economics. However, meaningful variations between simulation scenarios demonstrate that a simulation model is only valid for prediction if flow behavior in the reservoir remains consistent with that observed during the history matched period. Critically, this means that a simulation model calibrated for waterflooding may not fully capture the technical and economic benefits of an enhanced oil recovery process such as polymer flooding. Subsequently, the simulation model and economic model are used in conjunction to conduct a sensitivity analysis for polymer flood design parameters, from which recommendations are provided for both the continued operation of the current field pilot and future polymer flood designs. The results demonstrate that a higher polymer concentration can be injected due to the development of fractures in the reservoir. The throughput rate should remain high without exceeding operating constraints. A calculated point-forward polymer utilization parameter demonstrates the decreasing efficiency of the polymer flood at later times in the pattern life. Future projects will benefit from starting polymer injection earlier in the pattern life. A pattern with tighter horizontal well spacing will observe a greater incremental benefit from polymer flooding.
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Chapter 1  Introduction

1.1  Background

Heavy oil resources may constitute nearly 25% of the global oil reserve (Ibiam et al. 2021). Generally, heavy oils are classified as having an API gravity of 10° – 20° API and an in-situ viscosity between 100 to 10,000 cp; oils with a lower API gravity or greater viscosity may be classified as extra heavy oils or tar sands (Dandekar 2013). Often, heavy oils are contained in shallow, high-permeability poorly-consolidated sand formations (Mai and Kantzas 2008). Thus, the higher permeability formation may offset some of the challenges with mobilizing the viscous fluid. However, the unconsolidated sands are themselves prone to mobilization, leading to challenges with sand production and the formation of matrix bypass events (Paskvan et al. 2016).

Waterflooding has been applied in reservoirs with oil viscosity approaching 10,000 cp (Luo et al. 2017). Generally, though, heavy oil recovery under waterflooding is less than 20% (Gao 2011). The reason for this poor performance is readily apparent through considering the relative mobility between the injected water and displaced heavy oil. The mobility ratio is defined as the ratio of the mobility of the injected fluid to the mobility of the displaced fluid, typically oil (Green and Willhite 2018), or

\[ M = \frac{M_w}{M_o} = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} \]  

where \( M \) is the mobility ratio; \( M_w \) and \( M_o \) are the mobility of the injected water and displaced oil, respectively; \( k_{rw} \) and \( k_{ro} \) are the relative permeability of the injected water and displaced oil, respectively; and \( \mu_w \) and \( \mu_o \) are the in-situ viscosity of the injected water and displaced oil, respectively. If the mobility ratio is less than or equal to one, which is to say that the injected fluid is as mobile or less mobile than the oil, then a favorable piston-like displacement will be achieved (Ibiam et al. 2021). However, if the mobility ratio is greater than one, the displacing phase moves faster than the displaced phase, resulting in an early breakthrough of the injected fluid at the producing wells, a high producing water cut, bypassing of reserves, viscous fingering, and a reduced areal sweep (Anand et al. 2018; Ibiam et al. 2021). For heavy oils, the high viscosity leads to low oil mobility and thus a high mobility ratio compared to a much more mobile injected water. Thus, waterflooding a heavy oil will be inefficient because of a combination of low displacement
efficiency due to viscous fingering and low sweep efficiency due to reservoir-heterogeneity driven channeling (Luo et al. 2017; Anand et al. 2018).

The Alaska North Slope (ANS) contains a significant heavy oil resource within the Kuparuk River Unit, Prudhoe Bay Unit, Milne Point Unit, and Nikaitchuq Unit, as shown in Fig. 1.1 (Paskvan et al. 2016). Locally, these resources are sub-classified into viscous oil and heavy oil based on their reservoir, as described later.

![Figure 1.1 ANS viscous and heavy oil resource. The blue shading represents viscous oil, with the darker blue indicating areas under current development. The purple outline represents heavy oil, not yet developed (Paskvan et al. 2016)](image_url)

Most of the known ANS heavy oil resource is contained in the shallow-marine Schrader Bluff and non-marine Prince Creek formations (Decker 2007). These genetically-coupled formations were deposited in the Late Cretaceous and early Paleocene and were sourced by uplift of the Brooks Range, prograding eastward to northeastward across the present-day North Slope (Hubbard et al. 1990; Decker 2007). The formations are shallow and generally poorly consolidated (Decker 2007; Paskvan et al. 2016).
Reservoir charge occurred when continued uplift of the Brooks Range tilted the Kuparuk/Prudhoe structural high, causing oil to spill from deeper traps into the shallower West Sak, Schrader Bluff, and Ugnu reservoirs (Hubbard et al. 1990). Over 16 billion barrels of viscous and heavy oil in place have been reported cumulatively for the Schrader Bluff and West Sak reservoirs of the Schrader Bluff formation; an additional 10 billion barrels of heavy oil resource is contained in the Ugnu reservoir of the Prince Creek Formation (Bidinger and Dillon 1995; Decker 2007; Paskvan et al. 2016). Locally, resources in the West Sak and Schrader Bluff reservoirs are referred to as viscous oil even though the API gravity (11° – 24°API) and in-situ oil viscosity (5 – 10,000 cp) spans typical classifications of conventional black oil to heavy oil (Dandekar 2013; Paskvan et al. 2016). The resources in the Ugnu are locally referred to as heavy oil, though the reported API gravity range (7° – 12°API) spans classifications of heavy to extra heavy oil (Hallam et al. 1992; Dandekar 2013; Paskvan et al. 2016).

The majority of heavy oil production has occurred in the West Sak and Schrader Bluff reservoirs of the Schrader Bluff formation, comprised of the poorly-consolidated shallow-marine O and N sands (Bidinger and Dillon 1995). The homoclinal structure dips to the east-northeast at about two degrees, and the reservoir is frequently compartmentalized by complex faulting (McGuire et al. 2005). The deeper O sands, each about 10 to 35 feet thick, have been the main development target since they are generally more continuous and competent with better oil quality than the N sands (Bidinger and Dillon 1995; McGuire et al. 2005). However, the higher permeability N sands, about 5 to 15 feet thick, have recently received attention as a viable production target (Bidinger and Dillon 1995; Dandekar et al. 2019). No significant production has been reported in the Ugnu reservoir.

Field-scale production of ANS viscous oil resources began in the late 1990s (Targac et al. 2005). To date, only 150 million barrels have been produced, mostly from low viscosity (< 100 cp) portions of the reservoir (Paskvan et al. 2016). Still, even for these more favorable targets, waterflood recoveries frequently fall below 20% (Paskvan et al. 2016). The low recovery is motivated not only by the less favorable mobility ratio but also due to the frequent formation of matrix bypass events in the unconsolidated reservoir (Paskvan et al. 2016). Furthermore, higher viscosity portions of the reservoir have received limited attention and thus remain a large resource (Paskvan et al. 2016). It is clear that plenty of growth potential remains in Alaska’s heavy oil
resource if recovery from existing waterflood patterns can be improved and if higher viscosity tranches can be unlocked.

Enhanced oil recovery (EOR) methods have garnered significant attention for unlocking Alaska’s heavy oil resources (Paskvan et al. 2016; Garg et al. 2018). Thermal recovery methods have been applied globally to heavy oil resources; however, this is not practical on ANS due to environmental challenges, including the risk of damaging the 1,200 to 1,700 ft thick permafrost body overlying these shallow reservoirs (Hallam et al. 1992; Garg et al. 2018). Thin reservoirs and large well spacing further hamper thermal applications on ANS (McGuire et al. 2005; Paskvan et al. 2016). Additionally, today’s emphasis on low-carbon emissions makes thermal recovery even less attractive.

Miscible gas injection, another common EOR technique for heavy oil resources, is also impractical in ANS since the miscibility pressure between the heavy oil and solvent (hydrocarbon based or CO₂) would be much higher than the reservoir fracture pressure for economic injected gas compositions. Viscosity-reducing water-alternating gas (VR-WAG) injection has been applied on ANS, where a leaner gas is injected to reduce the oil viscosity and swell the oil (McGuire et al. 2005). This has led to a modest increase in recovery of 2-3% of the original oil in place (OOIP) over waterflood (Targac et al. 2005). However, new technologies are still being pursued to increase and improve exploitation from these large but challenging resources.

Polymer flooding may be such a technology. Adding polymer to the injected fluid increases the fluid viscosity, thus improving the mobility ratio and providing a more favorable displacement efficiency (Guo 2017; Luo et al. 2017; Green and Willhite 2018). This also improves the sweep efficiency by suppressing channeling into higher permeability zones (Luo et al. 2017). Furthermore, the polymer is relatively benign in its environmental impacts and carbon emissions, making it even more attractive to increase oil recovery without increasing the environmental risk or carbon footprint (Fabbri et al. 2014). Polymer flooding has been applied globally, with successful pilots and/or field-scale implementations in China, Canada, Oman, Suriname, Russia, and Argentina, among other locations (Thompson et al. 2018; Gbadamosi et al. 2019; Sabirov et al. 2020). By improving the mobility ratio, polymer flooding could be the key to unlocking heavy oil resources where thermal methods are not practical. For example, in the Pelican Lake and Seal heavy oil fields in Canada, polymer flooding has been successfully applied to in-situ oil viscosities.
as high as 10,000 – 12,000 cp (Delamaide 2018). Polymer flooding thus could help unlock the heavy oil resources on the Alaska North Slope.

To test this idea, the U.S. Department of Energy – National Energy Technology Laboratory and Hilcorp Alaska, LLC cosponsored the first ever polymer flood field pilot to enhance the recovery of heavy oils on the Alaska North Slope. An isolated fault-bound portion of the Schrader Bluff Nb sand within the J-Pad of the Milne Point Unit was selected for the field test. The oil API in this block is 15.4⁰API, the in-situ viscosity is 332 cp, and the horizontal permeability ranges from 500 to 5,000 mD (Ning et al. 2019). In mid-2016, two horizontal producing wells (J-27 and J-28) supported by two horizontal injecting wells (J-23A and J-24A) were drilled into this previously untouched fault block. The horizontal wellbore length varies from 4,200 to 5,500 ft and the inter-well distances range between approximately 1,100 and 1,500 ft (Ning et al. 2019). The producing wells were completed with sand exclusion screens to prevent sand production and matrix bypass event formation in this unconsolidated Nb sand. The injecting wells were completed with injection control devices and swell packers to isolate injection zones and limit thief behavior (Ning et al. 2019).

During the first two years of production, low-salinity water was injected without polymer. Injected water prematurely broke through into the producing wells within four months, and a high producing water cut subsequently developed. In August 2018, polymer injection facilities were installed at the J-Pad, and polymer injection commenced on August 28th. The water cut declined dramatically through 2019 and into 2020, falling from nearly 70% to less than 20%. In 2020, polymer breakthrough occurred in both producing wells, and the water cut has risen since, with a surge in water cut observed in J-28 in mid-2021. More importantly, since polymer injection began, the producing oil rate has remained relatively stable and three to four times higher than the forecasted oil rate expected for waterflooding alone. Thus, the pilot appears to be behaving acceptably.

While production trends indicate the polymer flood pilot is operating correctly, a true evaluation of the success of the project requires understanding the mechanisms motivating the positive behavior and then predicting the net benefit of the project across its full life. Reservoir simulation is a useful workflow for this purpose. A simulation model must be calibrated to correctly reproduce observed production trends; this history-matching procedure can elucidate the actual mechanisms behind these trends. The calibrated simulation model can then be used to
reliably forecast the expected production under a given operating scheme. This allows the overall technical benefit of the polymer flood pilot to be assessed. However, polymerflooding represents a significant economic investment, and a successful project would need to provide enough benefit to justify this additional expenditure (Delamaide 2018). Thus, an economic analysis of the predicted production response is important to determine whether the field pilot is economically successful. This will provide important insight into whether the expansion of polymer flooding for heavy oil on the Alaska North Slope is an attractive option.

1.2 Research Objectives
In this study, a reservoir simulation model was constructed, calibrated, and incorporated with an economic model to evaluate the first ever polymer flood field pilot to enhance the recovery of heavy oils on the Alaska North Slope. More specifically:

1. A range of reservoir simulation models were calibrated to various portions of the production history via machine-assisted history matching procedures. This process provided insight into the reservoir flow mechanisms driving positive and negative production trends.
2. These simulation models were used to forecast the oil recovery benefit of the polymer flood pilot, evaluated in reference to production expectations for waterflooding alone.
3. The simulation forecasts were input into a custom-built incremental economic model to analyze and evaluate the economic benefit of the polymer flood field pilot with reference to waterflooding alone.
4. The coupled simulation and economic models were used to conduct a sensitivity analysis of polymer flood design parameters in order to provide recommendations for the continued operation of the current polymer flood pilot and for the design of future polymer flood projects.

1.3 Brief Description of Chapters
Chapter 1 provides context for this study. It describes heavy oil resources and the challenges in exploiting these resources, with a brief overview of how polymer flooding could mitigate these challenges. The first ever polymer flood field pilot to enhance the recovery of heavy oils on the
Alaska North Slope is described to demonstrate the motivation behind this study, and the goals of the study are enumerated.

Chapter 2 describes the construction and calibration of a simulation model to reproduce the actual production history from the field pilot. The calibration process involves machine-assisted history matching procedures. The primary matching approach involves the modification of transmissibility contrasts in the model to reflect actual interpreted changes in flow behavior in the reservoir. The calibrated models are used to forecast the future oil recovery benefit of the polymer flood, allowing for a technical evaluation of the field pilot. The effect of the changing flow behavior on the technical evaluation is investigated. Chapter 2 is an accepted conference publication.

Chapter 3 focuses on the economic evaluation of the field pilot. The forecasts produced by simulation are input into a custom-built economic modeling tool, which calculates the predicted economic benefit of the polymer flood incremental to a base waterflood. The effect of the changing flow behavior on the economic evaluation is investigated. Finally, the simulation model and economic model are used in conjunction to conduct a sensitivity analysis with regard to the polymer flood design parameters. From this, recommendations for the continued operation of the field pilot and for the future design of polymer floods are provided. Chapter 3 is an accepted conference publication and is intended for submission in a peer-reviewed journal.

Chapter 4 consolidates the overall conclusions and recommendations drawn from this work.
Chapter 2  Technical Evaluation of Polymer Flood Pilot via Reservoir Simulation

2.1 Abstract

The first ever polymer flood field pilot to enhance the recovery of heavy oils on the Alaska North Slope is ongoing. This study constructs and calibrates a reservoir simulation model to predict the oil recovery performance of the pilot through machine-assisted reservoir simulation techniques. To replicate the early water breakthrough observed during waterflooding, transmissibility contrasts are introduced into the simulation model, forcing viscous fingering effects. In the ensuing polymer flood, these transmissibility contrasts are reduced to replicate the restoration of injection conformance during polymer flooding, as indicated by a significant decrease in water cut. Later, transmissibility contrasts are reinstated to replicate a water surge event observed in one of the producing wells during polymer flooding. This event may represent decreased injection conformance from fracture overextension; its anticipated occurrence in the other production well is included in the final forecast. The definition of polymer retention in the simulator incorporates the tailing effect reported in laboratory studies; this tailing effect is useful to the simultaneous history match of producing water cut and produced polymer concentration. The top 24 best-matched simulation models produced at each stage of the history matching process are used to forecast oil recovery. The final forecast clearly demonstrates that polymer flooding significantly increases the heavy oil production for this field pilot compared to waterflooding alone. This exercise displays that a simulation model is only valid for prediction if flow behavior in the reservoir remains consistent with that observed during the history matched period. Critically, this means that a simulation model calibrated for waterflooding may not fully capture the benefits of an enhanced oil recovery process such as polymer flooding. Therefore, caution is recommended in using basic waterflood simulation models to scope potential enhanced oil recovery projects.

2.2 Introduction

Globally, heavy oil resources may constitute up to 25% of the world’s oil reserve (Ibiam et al. 2021). These heavy oil resources are generally contained in high-permeability unconsolidated sand formations (Mai and Kantzas 2008). Although waterflooding has been applied in reservoirs with oil viscosity as high as 10,000 cp (Luo et al. 2017), generally heavy oil recovery is often less than 20% (Gao 2011). The relatively lower oil recovery in heavy oil reservoirs results from an unfavorable mobility ratio between water and heavy oil, leading to viscous fingering and low displacement efficiency (Mai and Kantzas 2008). This problem could be further amplified by reservoir heterogeneities that lead to channeling and an even lower sweep efficiency (Luo et al. 2017).

The Alaska North Slope (ANS) contains a significant viscous and heavy oil resource within the Kuparuk River Unit, Prudhoe Bay Unit, Milne Point Unit, and Nikaitchuq Unit, as shown in Fig. 2.1 (Paskvan et al. 2016). This resource is contained in the shallow-marine Schrader Bluff and non-marine Prince Creek formations (Decker 2007). These genetically-coupled formations are Late Cretaceous- to Paleocene-aged poorly-consolidated clastic deposits (Decker 2007). Over 16 billion barrels of viscous and heavy oil in place have been reported cumulatively for the Schrader Bluff and West Sak reservoirs of the Schrader Bluff formation; an additional 10 billion barrels of heavy oil resource is contained in the Ugnu reservoir of the Prince Creek Formation (Bidinger and Dillon 1995; Decker 2007; Paskvan et al. 2016). Thus, these resources are greater than those reported for the Prudhoe Bay reservoir (Bidinger and Dillon 1995). As of 2018, viscous oil makes up 6% of Alaska’s oil production (Garg et al. 2018).

ANS viscous oil production has occurred in the Schrader Bluff formation, comprised of the poorly-consolidated shallow-marine O and N sands (Bidinger and Dillon 1995). The homoclinal structure dips to the east-northeast at about two degrees, and the reservoir is frequently compartmentalized by complex faulting (McGuire et al. 2005). The deeper O sands, each about 10 to 35 feet thick, have been the main development target since they are generally more continuous and competent with better oil quality than the N sands (Bidinger and Dillon 1995; McGuire et al. 2005). However, the higher permeability N sands, about 5 to 15 feet thick, have recently received attention as a viable production target (Bidinger and Dillon 1995; Dandekar et al. 2019). No significant production has been reported in the Ugnu reservoir.
Field-scale production of ANS viscous oil resources began in the late 1990s (Targac et al. 2005). To date, only 150 million barrels have been produced, mostly from low viscosity (< 100 cp) portions of the reservoir (Paskvan et al. 2016). Still, even for these more favorable targets, waterflood recoveries frequently fall below 20% (Paskvan et al. 2016). Furthermore, higher viscosity portions of the reservoir have received limited attention and thus remain a large resource (Paskvan et al. 2016). It is clear that plenty of growth potential remains in Alaska’s viscous and heavy oil resource if recovery from existing waterflood patterns can be improved and if higher viscosity tranches can be unlocked.

Enhanced oil recovery (EOR) methods have garnered significant attention for unlocking Alaska’s viscous and heavy oil resources (Paskvan et al. 2016; Garg et al. 2018). Thermal recovery methods have been applied globally to heavy oil resources; however, this is not practical on ANS due to environmental challenges, including the risk of damaging the 1,200 to 1,700 ft thick permafrost body overlying these shallow viscous reservoirs (Hallam et al. 1992; Garg et al. 2018). Thin reservoirs and large well spacing further hamper thermal applications on ANS (McGuire et al. 2005; Paskvan et al. 2016). Additionally, today’s emphasis on low-carbon emissions makes the case for thermal recovery even less attractive. Miscible gas injection, another common EOR technique for heavy oil resources, is also impractical in ANS since the miscibility pressure between the heavy oil and solvent (hydrocarbon based or CO₂) would be much higher than the reservoir pressure for economic injected gas compositions. Viscosity reducing water-alternating gas (VR-WAG) injection has been applied on ANS, where a leaner gas is injected to reduce the oil viscosity and swell the oil (McGuire et al. 2005). This has led to a modest increase in recovery of 2-3% original oil in place (OOIP) over waterflood (Targac et al. 2005).

Polymer flooding has been successfully employed globally to increase oil recovery by reducing the mobility ratio, thus providing a more favorable displacement efficiency (Luo et al. 2017). Conventionally, polymer floods have been limited to oil viscosities less than 100 cp due to injectivity concerns (Gao 2011); however, horizontal injecting wells have allowed successful polymer projects in patterns with conservative live oil viscosities as high as 10,000 cp (Delamaide 2018). Furthermore, the polymer is relatively benign in its environmental impacts and carbon emissions, making it even more attractive to increase oil recovery without increasing the environmental risk or carbon footprint (Fabbri et al. 2014).
As such, the first ever polymer flood field pilot to enhance the recovery of heavy oils on the Alaska North Slope began in 2018. The project focuses on an isolated fault-bound portion of the Schrader Bluff Nb sand within the J-Pad of the Milne Point Unit (Fig. 2.2). The oil viscosity is about 330 cp in situ; additional reservoir properties are given Table 2.1 and Table 2.2. This fault block is being produced with two horizontal producing wells, J-27 and J-28, supported by two horizontal injecting wells, J-23A and J-24A. Production began in 2016 with waterflooding, and polymer flooding commenced in 2018. Because a waterflood preceded the polymer flood, this can be considered a tertiary polymer flood project (Fabbri et al. 2014). Additional details on the project and its implementation can be found in the literature (Ning et al. 2019, 2020; Dandekar et al. 2019, 2020). The project has been more successful than initially anticipated. After the implementation of polymer flooding, the producing oil rate has been maintained above the predicted oil rate for waterflooding, and a dramatic water cut reduction was observed. Thus, a simulation model for the ANS polymer flood field pilot is desired to investigate the mechanisms behind this positive behavior and then forecast expected benefits.

Reservoir simulation of waterflooding and polymer flooding in heavy oil reservoirs has met significant challenges and thus has gained a lot of attention in the literature. One key challenge is modeling the poor displacement efficiency and early water breakthrough during waterflooding. In particular, conventional reservoir simulators are known to fail in capturing viscous fingering effects accurately (Fabbri et al. 2015). Another concern is simultaneously matching production during both waterflooding and polymer flooding. According to Flora’s Rule, a reservoir model that has been history matched for one recovery strategy, such as waterflooding, may not be well matched for a different recovery mechanism if that mechanism changes the rock-fluid interactions or the mobility ratio, such as with polymer flooding (Ibiam et al. 2021).

A number of different approaches have been applied to history match heavy oil production under waterflooding and/or polymer flooding. Delaplace et al. (2013) applied assisted history matching techniques to a secondary polymer flood pilot in the Pelican Lake Heavy Oil Field; they had to create a heterogeneous horizontal permeability distribution to achieve a reasonable history match. Fabbri et al. (2015) match a laboratory scale tertiary polymer flood by applying a hysteresis model to the relative permeability curves history matched for the waterflood period. For waterflooding, Mostaghimi et al. (2015) introduce a dynamic adaptive mesh to the simulation grid to recreate viscous fingering effects triggered by white-noise disturbances in the water saturation,
while Luo et al. (2017) simulate the behavior through an effective fingering model executed through relative permeability pseudoization. Anand et al. (2018) achieve a well level match for high water cuts during waterflooding and early polymer breakthrough during polymer flooding by introducing permeability heterogeneities, justified as representing high permeability zones or fractures. Thompson et al. (2018) history matched a tertiary polymer flood pilot by tuning relative permeability at the facies level along with the vertical and horizontal permeability. Sabirov et al. (2020) history match a tertiary polymer flood by tuning the relative permeability and polymer flood parameters.

In our previous work, the ANS field pilot team had constructed and calibrated a simulation model describing the polymer flood pilot (Wang et al. 2021). In history matching the waterflood period, high transmissibility strips were introduced between injector and producer well pairs, similar to the approach of Anand et al. (2018). However, it was found that these transmissibility contrasts had to be modified over time to replicate the polymer flood performance. These contrasts were justified as directly forcing the viscous fingering behavior expected during waterflooding. The subsequent overall reduction in strip transmissibility during polymer flooding represents the dampening of these instability effects (Wang et al. 2021). While this justification seems reasonable, it does not explain the increase in strip transmissibility introduced at the beginning of the polymer flood period. Furthermore, additional production data collected since this work merits revision of the model in order to match recent well events and produced polymer concentration information.

This work repeats the history matching exercise to calibrate a reservoir simulation model to the production observed from the ANS polymer flood field pilot. We take the same overall approach as before of introducing transmissibility heterogeneities in the form of strips. However, machine-assisted history matching techniques are applied in order to: simplify the frequency of strip transmissibility changes in the model; simultaneously match the producing water cut and produced polymer concentration along with the bottomhole pressures (BHP) of all wells; and produce a range of feasible calibrated models for uncertainty analysis. Those transmissibility changes that do occur are justified through potential real-world alterations to the flow structure in the reservoir. Specifically, we find that the strips must be introduced during the waterflood period in order to recreate the fingering effects expected when heavy oil is displaced by high-mobility water. The transmissibility contrast must be reduced during the polymer flood period in order to
replicate the dampening of fingering effects and restoration of injection conformance. However, an anomalous water cut surge in well J-28 during 2021 required a corresponding increase in the strip transmissibility. This suggests a reduction in the injection conformance during this period, explainable through fracture overextension.

Each time a change in transmissibility contrast occurs, a polymer flooding forecast is produced to understand the influence of this changing parameter on the oil recovery. These polymer flooding forecasts are compared to a waterflood-only forecast, based on the model history matched to the waterflood period only. Thus, four different models are constructed: a waterflood-only scenario, a model that is history matched up until the restoration of injection conformance from polymer flooding in mid-2019 (Model A), a model that is history matched until the water cut surge in J-28 in 2021 (Model B), and a model that fully matches the entire current history (Full Model). In each case, the top 24 history matched models are used to illustrate the history match uncertainty. Because we expect well J-27 to experience a surge similar to well J-28 in the future, a sensitivity to surge timing is conducted using the Full Model and a conservative timing is incorporated into the Full Model forecast. Forecasts from all four models with uncertainty are then compared to illustrate how dynamic reservoir events can change oil recovery expectations.

2.3 Methodology

2.3.1 Simulation Model Construction

The base reservoir model was created for use in a black-oil simulator. The black-oil simulator was deemed appropriate for polymer flooding in a heavy oil reservoir because the undersaturated oil has a low GOR and the polymer is designed only for the improvement of sweep efficiency; thus, the process is immiscible and non-compositional (Delaplace et al. 2013; Ibiam et al. 2021).

A plan view of the reservoir model is shown in Fig. 2.3. The model uses a corner-point grid with about 74 x 40 x 8 active grid blocks, spanning approximately 7,400 ft x 4,700 ft x 15 ft. Grid top values are indicated by the color contours. Units are in feet. Well trajectories are indicated with thick black lines. Injecting wells (J-23A and J-24A) are labeled in blue font, and producing wells (J-27 and J-28) are labeled in green font. For lack of more detailed geologic information, each of the eight layers is assigned a constant porosity and permeability, shown in Table 2.1. Horizontal permeability is assumed isotropic, and the vertical permeability is
calculated as seventy percent of the horizontal permeability in each layer. Additional reservoir properties are shown in Table 2.2.

Cores and fluid samples collected from the Schrader Bluff Nb sand near the project area were used in laboratory analysis to obtain routine and special core analysis data and PVT properties. The laboratory relative permeability data was fit with the Corey Exponent correlation to produce the base relative permeability curve shown in Fig. 2.4. Circles indicate the measured laboratory values used in the base simulation model, and the lines indicate the history-matched calibrated curves. Green indicates oil relative permeability, and blue indicates water relative permeability. Note that the laboratory relative permeability measurements were taken using high salinity water while the water used in the field is from a low salinity source.

Hydrolyzed polyacrylamide or HPAM (Flopaam 3630S) was predominantly used for the field pilot. The properties needed to model polymer flooding in the black-oil simulator were measured in laboratory analysis. The polymer solution viscosity is specified as a function of both polymer concentration and fluid shear rate, as shown in Fig. 2.5 (Wang et al. 2021). The polymer retention is plotted as a function of polymer concentration, as shown in Fig. 2.6, incorporating the significant tailing effect reported by Wang et al. (2020). A linear interpolation model from the origin to the maximum retention value is shown in orange for comparison. The inaccessible pore volume was deemed negligible for these high permeability sands; this conservative approach was confirmed by laboratory analysis (Manichand and Seright 2014; Wang et al. 2020). Finally, the residual resistance factor was deemed negligible in laboratory analysis, again a conservative approach (Seright 2017).

Well trajectories and perforations were provided by the field operator. For the base simulation model, the skin factor for each well is taken as -3.0. Production histories for J-27 and J-28 are shown in Fig. 2.7. During the production history, the producing wells are constrained to match the actual oil rate since this is the most precisely measured fluid stream. The injecting wells are constrained to match the actual water injection rate, and the injected polymer concentration is based on the actual injected polymer concentration history. The injection rate histories for J-23A and J-24A are shown in Fig. 2.8.
2.3.2 History Matching

To be considered a useful tool for understanding the current flow behavior in the reservoir and providing production forecasts, the simulation model should be able to reasonably recreate the actual observed production history. This necessitates a history matching exercise, where parameters in the simulation model are modified until an adequate match to production history is obtained. Since the producing wells are constrained to match the actual oil rate, the producing water cut is used as a history match objective function. The BHP in both injecting and producing wells is used as a second objective function in order to ensure that the injectivity and deliverability of the simulation model are valid for forecasting. Finally, with any chemical flood, the breakthrough of the chemical into the producing wells provides crucial insight into the effectiveness of the EOR program (Delaplace et al., 2013; Anand et al., 2018). Thus, the produced polymer concentration in both producing wells is honored as a third objective function in history matching.

A number of parameters are tuned for this history matching process. In order to match the abrupt and dramatic changes in the water cut observed in both producing wells, Wang et al. (2021) introduced high transmissibility strips to the model, shown in Fig. 2.9. Each strip is assigned a transmissibility multiplier in the direction of the pressure gradient, and the multipliers were allowed to change in time in order to match the dominant abrupt changes in behavior. Strips are identical in each layer of the model. We use the same approach in our history matching exercise. In order to match the produced polymer concentration, the strips are assigned a retention value of zero.

On the basis of previous work (Wang et al. 2021), we also introduce transmissibility multipliers to the blocks in between the strips, shown in Fig. 2.10. White indicates the location of strips, and magenta indicates areas with no additional multiplier. These inter-strip-blocks are assigned a transmissibility multiplier less than unity. The entire “west end” is treated as a single block. These block multipliers are constrained to reduce the transmissibility and are not changed with time. The block multipliers represent possible horizontal heterogeneity in reservoir permeability.

Additionally, the relative permeability curves are tuned through modification of the endpoint water relative permeability, the critical water saturation, and the Corey exponents for both the oil and water curves (Fig. 2.4). Note that the initial water saturation is initialized
separately in the simulation model, so changing the critical water saturation in the relative permeability curves does not impact the OOIP calculation in the model. The range of changes in relative permeability parameters is closely constrained to honor the laboratory measurements. As such, we consider ourselves to be tuning – but not pseudoizing – the relative permeability in the history matching procedure. Furthermore, the relative permeability curves do not change with time.

The skin factor for each well is used as a tuning parameter to match the BHP. The overall reservoir transmissibility is also tuned to match the actual reservoir deliverability by introducing “blanket” transmissibility multipliers between each injector-producer well pair. These multipliers are applied to all grid cells between each well pair and accumulate with the aforementioned strip and inter-strip block transmissibility multipliers. Because the strip transmissibility multipliers change with time, it is necessary to change these blanket multipliers with time as well to ensure the simulated injectivity and deliverability is consistent with the actual reservoir for the full history.

Clearly, a large number of parameters are tuned in this history matching exercise. In order to efficiently optimize these parameters to minimize the history matching error, a machine assisted history matching software was utilized. The user specifies the range of acceptable values for each tuning parameter along with the history matching objective functions, and then the software seeks the optimal combination of parameters to minimize the objective function error. As Delaplace et al. (2013) note, this process is highly iterative. First, the user must thoughtfully select tuning parameters, parameter ranges, and objective function weights; then, they must carefully inspect simulation results for quality and reasonability. If the results are deemed inadequate, the parameters, ranges, and weights must be modified, and the algorithm runs again. As an additional benefit, the assisted history matching software can produce a large number of reasonable history matched models, allowing for a range of calibrated models to be carried forward into forecasting, which is beneficial for uncertainty analysis.

To produce the most reasonable model, we seek to minimize the frequency of parameter changes with time. As such, the history matching process starts with no parameter changes with time. The software produces the best possible history match under these constraints, and the user observes where the model behavior fundamentally deviates from the actual production history. A change in strip transmissibility multipliers and inter-well blanket transmissibility multipliers is
specified at this point in time, and the history matching software is rerun. This process iterates until an adequate history match is achieved.

2.3.3 Forecasting
After the simulation model is calibrated via the history matching process, it is used for forecasting future production to evaluate the success of the polymer flooding field pilot. In forecasting, each injecting and producing well is constrained based on its current liquid rate and BHP. The liquid rate constraints are adjusted to maintain a voidage replacement ratio near unity, critical for pressure maintenance and avoidance of matrix bypass events (Paskvan et al. 2016). In some cases, the simulated BHP is slightly offset from the actual data. The BHP constraint is modified in forecasting to compensate these mismatches. The constraints for polymer flood forecasting are shown in Table 2.3. Note that the simulator will attempt to achieve the specified liquid rate constraint for each well unless the BHP constraint is exceeded. If this is the case, the well will run on the BHP constraint until it can achieve the liquid rate constraint again. Note that all of the top 24 history matched models are run on the same constraints. Since these models produce different BHP matches, this variability can be thought of as an injectivity and deliverability uncertainty test.

To evaluate the success of the polymer flood, its production must be compared to the production expected under waterflooding alone. This waterflood base case is constructed by putting the simulator on forecasting starting from the date when waterflooding ended and polymer flooding began. The configuration of strips used to history match the waterflood period is carried forward into the waterflood forecast. Waterflood forecasting constraints, shown in Table 2.4, are based on historical well performance during the actual waterflood period.

During the history matching process, it was found that the strips between J-23A and J-28 had to be changed in 2021 to match the rapid increase in water cut in that year, as shown in Fig. 2.7b. This surge event has not yet been observed in J-27, and a critical uncertainty is whether it will occur in the future. Therefore, multiple forecasts were run with various timing for surge occurrence to test the possible effects of a water surge in J-27. The event was simulated by introducing one-cell width strips between J-27 and its neighboring injectors, analogous to the approach used to match J-28. For lack of better information, these strips were assigned the same transmissibility multipliers as those used to match J-28 in 2021. Six cases were run with variable
surge timing for J-27: immediate surge (mid-September 2021), surge at the start of 2022, mid-2022, the start of 2023, the start of 2024, and then no surge.

One of the novel aspects of this work is the incorporation of the tailing effect into the polymer retention table. The impact of this more precise retention specification is studied by comparing the best matched model forecast with a forecast performed using linear interpolation between only the maximum value of retention (at the maximum polymer concentration) and the origin (orange line in Fig. 2.6).

We find that the transmissibility contrast must be changed twice in time to fully match the polymer flooding production history. As described later, the timing of these is explainable through events in the reservoir that fundamentally alter flow paths. Of interest is how these events affect the oil recovery forecast. As such, we create separate cases incorporating each subsequent change. This means that three polymer flooding cases are created: Model A is matched for the waterflooding and early polymer flooding periods through mid-2019; Model B is matched for these periods plus the stable polymer flood through 2020; and the Full Model is matched for the entire history, including the observed surge event in J-28 along with an anticipated similar event in J-27. Forecasts are produced for each of the three polymer flooding cases, walking through the same time steps and constraints in order to compare the influence of these reservoir events on both the production history and future production. For each case, the top 24 history-matched models, defined as having the lowest objective function history matching errors, are used to compare the ranges in these predictions.

2.4 Results

2.4.1 Base Model

The base reservoir simulation model was run prior to history matching work. Simulated water cut results for both producing wells for all models are shown in Fig. 2.11. The base model results are indicated with the blue line, while the black circles represent the actual production history. As can be seen, the base model fails to replicate the early water breakthrough and high water cut observed in the actual production data. Furthermore, it does not capture the magnitude of water cut reduction observed during the polymer flooding period, nor does it capture the increase in water cut in J-28 in 2021. This demonstrates that the model must be calibrated to the production data before it is useful for forecasting.
2.4.2 Model A: Waterflood and Early Polymer Flood

2.4.2.1 Model A History Match

In order to match the early water breakthrough and high water cut observed during the waterflood period, transmissibility contrasts were introduced to the reservoir model in the form of the strip and block arrangement in Fig. 2.9 and Fig. 2.10. Transmissibility multiplier values, along with other history matching parameter values, are given in Table A-1. Values are shown for the best matched model along with the minimum and maximum among the top 24 matched models. The timing for when the parameter takes effect in the model is indicated with the “Start” column. The timing for when strip transmissibility multipliers are replaced is indicated by the “Replace” column. Note that the inter-well multipliers are not replaced, but instead aggregate. This first history match attempt, with transmissibility contrasts introduced to match the early production history, is referred to as “Model A.”

The resulting water cut history match for Model A is indicated in gray in Fig. 2.11, with the best matched model results indicated with the dark gray line and the range of results from the top 24 models represented with the light gray shaded area. The introduction of transmissibility contrasts successfully recreated the early water breakthrough and high water cut observed during the waterflood period. An adequate history match is maintained through the first eight months of the polymer flood period. However, the model fails to replicate the significant reduction in water cut observed after the polymer flood has matured after eight months. Thus, Model A successfully history matches the data through mid-2019 but is inadequate afterwards.

2.4.2.2 Continuous Waterflood Forecast

Since the waterflood period is adequately history matched by Model A, a base forecast on continued waterflooding was produced for each of the top 24 matched models. This waterflood-only prediction assumes no polymer flooding occurs; as such, the forecast begins in September 2018 and ends in June 2050. The oil recovery factor for the waterflood only case is shown in blue in Fig. 2.12. Outcomes ranged from 19-21% of the OOIP recovered by 2050, with the best matched model predicting 19.9% recovered under waterflooding alone.
2.4.2.3 Model A Polymer Flood Forecast

While an adequate history match for the full production history had not yet been achieved, a forecast from mid-2019 to 2050 was conducted for polymer flooding using Model A. This represents a project evaluation conducted at this point in the pilot’s life (mid-2019), prior to collecting the additional data that contradicts Model A. The oil recovery factor predictions for polymer flooding using Model A are shown in gray in Fig. 2.12. Outcomes ranged from 32-34% of the OOIP recovered by 2050 using polymer flooding, with the best matched model predicting 33.4% oil recovery.

2.4.3 Model B: Mature Polymer Flood

2.4.3.1 Model B History Match

Model A is unable to replicate the dramatic 50% decrease in water cut observed in mid-2019. To reproduce this extreme behavior, the three-cell width strips (i.e., B, C, D, F, G, H, J, K, and L in Fig. 2.9) were removed. Furthermore, the half-cell width strip (i.e., A, E, and I in Fig. 2.9) transmissibility was reduced. Finally, an additional accumulative “blanket” transmissibility multiplier was applied between each well pair. This is justified by the necessity to maintain a reasonable BHP match, thus continuing to honor the reservoir injectivity and deliverability. The new strip configuration is shown in Fig. 2.13, and the timing of these changes is provided in Table A-1. This new model is referred to as “Model B” for the remainder of this paper.

The resulting water cut history match for Model B is indicated in red in Fig. 2.11, with the best matched model results indicated with the dark red line and the range of results from the top 24 models represented with the light red shaded area. The second gold line indicates the timing of the reduction in strip transmissibility. As can be seen, the reduction in the transmissibility contrast successfully recreated the low water cut observed after the polymer flood benefits became apparent in mid-2019. The water cut history match is adequate for J-27 for its entire history, but is inadequate for J-28 in 2021. Here, the actual water cut increased rapidly to nearly 60% by August 2021, and Model B is unable to replicate this surge.

The produced polymer concentration history match for both producing wells is shown in Fig. 2.14. Actual field measurements are indicated by black circles. Model B is shown in red, with the solid dark red line indicating the best matched model and the light red shaded area representing the range of results from the top 24 models. Model B is able to match the moderate
produced polymer concentrations at the end of 2020 and the beginning of 2021, but it is unable to replicate the much higher values observed later in 2021. Improvements are desired.

2.4.3.2 Model B Polymer Flood Forecast

While an adequate history match for the full production history had not yet been achieved, a performance forecast for polymer flooding from the end of 2020 to 2050 was conducted using Model B. This replicates the project evaluation that would have been produced at this point in the pilot’s life (end of 2020), prior to the collection of the additional data that contradicts Model B. The oil recovery factor predictions for polymer flooding using Model B are shown in red in Fig. 2.12. Outcomes ranged from 38-42% of the OOIP recovered by 2050, with the best matched model predicting 40.6% recovered.

2.4.4 Full Model: J-28 Surge

2.4.4.1 Full Model History Match

In order to match the high water cut encountered in J-28 in mid-2021, one-cell width high transmissibility strips were returned in between J-23A and J-28. Furthermore, the half-cell width strip transmissibility was increased to match the higher produced polymer concentration in both producing wells. Finally, an additional accumulative “blanket” transmissibility multiplier was applied between J-23A and J-28 to maintain a reasonable BHP match and thus continue to honor the actual reservoir deliverability and injectivity. The new configuration is shown in Fig. 2.15, and the timing of these changes is provided in Table A-1. This new model, matched through all current production data, is referred to as the “Full Model” for the remainder of this paper.

The resulting water cut history match is shown green in Fig. 2.11, and the produced polymer concentration match is shown in green in Fig. 2.14. In both cases, the dark green line indicates the results from the best matched model, while the light green shading displays the range of values achieved by the top 24 models. The additional gold line indicates the timing of the increase in strip transmissibility in 2021. Note that the one-strip width blocks needed to be opened in January 2021 to ensure a reasonable match of the produced polymer concentration, even though this results in an earlier increase in water cut in J-28 than was observed in the actual data.

The BHP history match for all wells using the Full Model is shown in Fig. 2.16. BHP constraints used for polymer forecasting are indicated with a blue dashed line. While there is some
mismatch in the polymer flooding BHP history, particularly for J-27, the overall behavior is consistent with the actual production history, and the mismatches during the polymer flood period can be accommodated by modifying the forecasting BHP constraints. All history matching objective functions have been matched well enough to have confidence in the usefulness of the Full Model for prediction.

2.4.4.2 J-27 Surge Timing Sensitivity Analysis

Before the full model can be used for forecasting, the anticipated occurrence of a surge event in J-27 analogous to the event observed in J-28 must be considered. The polymer flood expected ultimate oil recovery prediction for varying anticipated timing for water surging in J-27 is shown in Table 2.5. If surging occurs in J-27, the recovery decreases dramatically. In general, earlier surging resulted in slightly lower recovery compared to a delayed surge. Importantly, in all cases, the recovery with polymer flood exceeds that predicted for waterflooding alone.

While assuming that the surge occurs immediately at the start of forecasting is unreasonably pessimistic, the conservative approach is to assume the surge occurs sooner rather than later. As such, the polymer flood forecast for the Full Model assumes that a water surge event occurs in J-27 at the start of 2022.

2.4.4.3 Full Model Polymer Flood Forecast

For the Full Model, the top 24 history matched models are forecasted assuming a surge event in J-27 at the start of 2022. The oil recovery factor predictions for polymer flooding using the Full Model are shown in green in Fig. 2.12. Outcomes ranged from 34-36% of the OOIP recovered by 2050, with the best matched model predicting 35.0% recovered.

The oil recovery for the best-matched Full Model polymer flood and the best-matched waterflood forecasts are plotted against the pore volumes injected in Fig. 2.17. Note that while fewer pore volumes of polymer solution are injected, higher oil recovery is achieved than under waterflooding alone. This suggests that the polymer solution is more efficient at displacing oil toward the producing wells.
2.4.4.4 Effect of Retention Tailing

The producing water cut and polymer concentration history match using the Full Model with and without the retention tailing effect are shown in Fig. 2.18 and Fig. 2.19, respectively. The use of the linear model in place of the tailing model increases the water cut and decreases the produced polymer concentration during 2020 and 2021, reducing the quality of the history match. This indicates that the inclusion of the retention tailing effect is significant to the success of this history matching process.

The incorporation of retention tailing results in a higher anticipated oil recovery than the simpler but less accurate linear model. By 2050, the linear model predicts an oil recovery of 33.2%, notably lower than the 35.0% predicted by the forecast with the retention tailing effect.

2.4.5 Forecast Comparison

The oil recovery forecasts produced by Model A, Model B, the Full Model, and waterflooding alone are compared in Fig. 2.12. As can be seen, Model A produces the most pessimistic results, Model B is the most optimistic, and the Full Model (including the anticipated water surge in J-27 at the start of 2022) predicts an intermediate oil recovery. Importantly, all three polymer flooding models predict significantly higher oil production under polymer flooding compared to waterflooding alone.

2.5 Discussion

Our simulation approach focuses on introducing transmissibility contrasts to recreate flow behaviors that appropriately motivate the trends in production history. Other works have sought to achieve similar goals through the pseudoization of relative permeability (Fabbri et al. 2015; Luo et al. 2017). In reproducing the effects of reservoir heterogeneity, relative permeability pseudoization can severely distort the relative permeability curves (Delaplace et al. 2013). Thus, we prefer to introduce reasonable transmissibility heterogeneity at the grid scale. That said, simulation work can be sensitive to uncertainties in relative permeability measurements; in our case, we know that the water used for the laboratory core flooding is higher salinity than the water injected in the field. As such, we do still tune the relative permeability during our history matching process, similar to the approach pursued by Delaplace et al. (2013) and Sabirov et al. (2020). Interestingly, both our work and that reported by Delaplace et al. (2013) noted that the endpoint
water relative permeability had to be reduced. In our case, the discrepancy is likely attributable to differences in water salinity, with the laboratory experiment utilizing high salinity water while the actual injection water is from a low salinity source.

A novel key to our history match was the inclusion of the retention tailing effect measured in the lab as described by Wang et al. (2020). It is understood that high retention values (greater than 200 μg/g, for instance) can lead to poor economic performance (Manichand and Seright 2014). However, the inclusion of the retention tailing effect rectifies large retention measurements with otherwise anomalous positive performance (Wang et al. 2020). The tailing effect suggests that about 70% of the injected polymer propagates through the reservoir rapidly with low retention (Wang et al. 2020). This helps to explain some of the production trends noted in this field pilot, such as the low water cut associated with higher produced polymer concentration in late 2020 and through 2021 (especially in well J-27). Furthermore, neglecting the tailing effect in favor of a linear retention model will result in overly pessimistic evaluations, perhaps erroneously excluding successful polymer projects.

The use of machine-assisted history matching software was critical to improved calibration of this model over the results obtained in a previous simulation study for this pilot (Wang et al. 2021). Similar to the expectations reported by Delaplace et al. (2013) and Ibiam et al. (2021), the assisted history matching process achieved a better match than what is reasonably expected through manual history matching, with the added benefit of a range of feasible models. In particular, the assisted history matching process allowed more parameters to be varied independently, such as the individual transmissibility multipliers for each strip. We consider our calibrated model to be an improvement over the Wang et al. (2021) model in that transmissibility multipliers are changed in time much less frequently. Furthermore, each of those changes in time can be explained through fundamental changes in the behavior of the reservoir.

Consider Model A, calibrated through the waterflood period. This history match is needed to recreate the premature water breakthrough and high water cut observed in both production wells, indicative of poor injection conformance. Transmissibility heterogeneities were introduced regionally to a pattern of strips and blocks, similar to the history match concepts of Delaplace et al. (2013) and Anand et al. (2018). Without further information, one could legitimately argue that these strips represent high permeability channels or fractures; thus, one would expect this transmissibility contrast to remain even with the introduction of polymer flooding. Indeed, given
that the block transmissibility multipliers do not change with time in our model, we believe these block multipliers do recreate a reasonably heterogeneous horizontal permeability in an otherwise oversimplified homogeneous layer model. The strip transmissibility multipliers are a different story, as will be explained shortly.

Operating on the assumption that the transmissibility contrasts will not change with the introduction of polymer flooding, one would apply Model A to produce the forecast shown in gray in Fig. 2.12. Comparing the predictions of Model A to the actual production data from mid-2019 onward (Fig. 2.11), we see that this model fails to capture the significant decrease in water production attributable to the introduction of polymer flooding. Model A also requires extremely low producing BHPs to meet the oil rate actually achieved from 2019 onward, resulting in the shut-in of the producing wells for a number of months at the start of forecasting. So, Model A is clearly pessimistic, failing to capture the full benefit of polymer flooding and predicting a deliverability issue that was not observed. To overcome this mismatch and correctly reproduce the dramatic water cut decrease and apparent restoration of injection conformance in mid-2019, the transmissibility contrast between the strips and the blocks was reduced by lowering the strip transmissibility multipliers, producing Model B (Fig. 2.13). This now redefines our understanding of what the strips represent. Because the strips’ transmissibility must change with time, they are unlikely to represent simple permeability heterogeneity since permeability is typically constant. The change in the strip transmissibility seems tied to benefits provided by the polymer, with some delay in the effects as the polymer flood matured and came to dominate the reservoir flow structure. Thus, the presence of the strips likely represents an inefficiency in waterflooding that is overcome with polymer flooding.

It has been well documented that conventional simulators do not organically recreate viscous fingering effects (Fabbri et al. 2015). When mobile water displaces a less-mobile heavy oil, the poor mobility ratio leads to viscous fingering, causing an early water breakthrough in the producing wells. By injecting a polymer solution, the less mobile injected fluid has a more favorable mobility ratio with the heavy oil, reducing these fingering effects. The high transmissibility strips can thus be interpreted as a forcing mechanism for the viscous fingering expected during the waterflood period, an effect that could motivate the early water breakthrough and high water cut observed in the producing wells. The introduction of polymer necessitated the removal of these strips to reflect the reduction in fingering behavior.
Fig. 2.20 illustrates this concept by depicting the streamlines in the simulation model. The high transmissibility strips in the waterflood encourage viscous fingering-type behaviors that lead to delays in sweeping bypassed oil zones. These strips are removed during polymer flooding, reflecting the reduction in viscous fingering behavior and resulting in previously bypassed oil zones being swept much sooner.

During the waterflood period, most of the injected water goes through the high transmissibility strips directly to the producers, creating a finger-like effect and bypassing significant oil reserves. If waterflooding continued, we would expect this effect to continue as well; accordingly, the waterflood forecast maintains the same strip transmissibility arrangement as Model A. However, when polymer flooding commences and has matured to dominate the reservoir flow behavior, the fingering effect is reduced, and those bypassed oil zones begin to be swept.

It is worth noting that viscous fingering is not the only possible justification for the introduction of high transmissibility strips during waterflooding and subsequent reduction during polymer flooding. For example, the polymer may interact with high permeability zones or fractures, plugging these features and diverting injection to the unswept zones (Xu and Lu 2020). We favor the viscous fingering explanation over this diversion explanation for a number of reasons. Firstly, we found that to maintain the BHP match, an overall increase in transmissibility between each well pair was necessary even as the strip transmissibility multipliers were reduced. This suggests that the polymer flood did not influence reservoir injectivity and deliverability in proportion to the conformance improvement. This observation disfavors a plugging mechanism as fully describing the dramatic water cut reduction. In addition, only partially hydrolyzed polyacrylamide polymer is being injected; no cross-linker is present, and the polymer is not designed to swell in the formation. The polymer solution is designed to improve the mobility ratio, not to plug fast connection zones; the mechanism behind the improvement in conformance should be driven by mobility effects such as viscous fingering reduction. In reality, some combination of viscous fingering and fracturing may explain the observed production behavior.

The produced polymer concentration data indicated that the restoration of injection conformance with polymer flooding was not perfect. This is seen in the timing of polymer breakthrough when the polymer was first observed in the producing wells in late 2020 (Fig. 2.14). In Model B, the half-cell width strip transmissibility multipliers were reduced but allowed to
remain higher than the surrounding matrix, leaving some connection between the producers and injectors to replicate the early arrival of the polymer at the producers. To encourage this higher produced polymer concentration without also incurring an erroneously high water cut, the strips were all assigned a retention value of zero. This is justified given that retention can be variable in a reservoir due to variations in mineralogy (Manichand and Seright 2014). However, this extremely low retention value may indicate more of a fracture-type feature, where low or zero retention values have been reported (Wang et al. 2020). From this assessment, we believe that the introduction of polymer flooding improved injection conformance by reducing fingerling effects. However, the presence of fractures or high permeability channels in the reservoir prevented perfect conformance from being achieved.

Assuming this improved injection conformance holds, Model B produces the oil recovery forecasts shown in red in Fig. 2.12. Model B’s forecasts are much more optimistic than Model A’s, a justified optimism since Model A fails to capture the full benefit of polymer. However, while Model B’s history match holds through early 2021, Fig. 2.11 and Fig. 2.14 show that Model B fails to capture key production trends in mid-2021, including a water surge event that produced a higher water cut in J-28 and the higher produced polymer concentration observed in both producing wells. Thus, at this point in 2021, the improved injection conformance established in 2019 and 2020 seems to break down. As such, adjustments are made in 2021 to produce the fully history matched model. These adjustments include increasing the transmissibility multiplier on the half-cell strips for both producing wells to match the higher produced polymer concentration and reintroducing strips between J-23A and J-28 to capture the abrupt water surge event. For lack of better information, the reintroduced strips are placed in the same location as during the waterflood period. This is justifiable since the previous water injection would have improved the water relative permeability in these zones, so we would expect this polymer solution surge to occur in these previously swept areas rather than in previously bypassed zones (Thompson et al. 2018). That said, it was found that the strip width needed to be decreased to one grid cell to produce the best history match.

We believe this third strip arrangement implemented in the model in 2021 represents the effects of fracture overextension. Khodaverdian et al. (2010a) describe in detail how a fracture could develop during polymer flooding in unconsolidated sand. They point out that solids in the injection fluid can plug the sandface, leading to fracturing. During the ANS field pilot operations,
undissolved polymer beads ("fish-eyes") were observed in the injected fluid, potentially acting as solids that could plug the sandface and initiate a fracture. High injection rates of polymer solution into the heavy oil could lead to fracture propagation (Khodaverdian et al. 2010a). However, in an unconsolidated sand, these fractures would propagate through branching, forming a series of short subparallel fractures and zones of enhanced permeability referred to collectively as a "pseudofracture" (Khodaverdian et al. 2010a). As further evidence favoring a fracturing-type mechanism for the water surge observed in J-28 during polymer flooding, examining Fig. 2.16 shows that injection pressures increased substantially during polymer flooding relative to waterflooding. These pressures likely exceed the parting pressure of the shallow unconsolidated formation. While fracturing is often needed to maintain injectivity during polymer flooding, the "pseudofracture" may have propagated beyond the one-third producer-injector distance recommended, leading to a loss in injection conformance and the resulting water surge in J-28 (Khodaverdian et al. 2010b; Choudhuri et al. 2015; Seright 2017).

Fracturing or sand parting is not the only feasible explanation. In mid-2020, the operator reduced the target polymer viscosity from 40 cp to 30 cp, with the actual injected solution viscosity dropping as low as 20 cp. This reduced viscosity may be too low to maintain the improved injection conformance established with the previous 45 and 40 cp viscosity targets. Thus, viscous fingering effects may have returned, though to a lesser extent than observed during the waterflood. These two explanations are not exclusive; some combination could explain the water surge observed in J-28. With that said, the 10 cp reduction in injected viscosity is unlikely to produce fingering effects extreme enough to fully explain the dramatic and abrupt water cut increase in J-28. As such, we favor a fracturing-type mechanism to explain this behavior.

Since this surge event was observed in J-28, there is a likelihood that a similar event could occur in J-27. If polymer breakthrough is an indicator for this event occurring, then a surge is indeed imminent. Based on our forecast sensitivity, the earlier this event occurs, the more detrimental it is to the oil recovery. Therefore, we assume that the surge event is caused by fracturing, fingering, or another mechanism that occurs in J-27 at the start of 2022. The forecasts produced from this fully matched model are shown in Fig. 2.12. Accounting for the surge event produces a more pessimistic forecast than what was given by Model B, but the forecast remains more optimistic than that assumed for Model A. Another important takeaway from this figure is that, for all cases, oil recovery under polymer flooding exceeds that forecasted for waterflooding.
in both early and late times. Thus, the 330 cp heavy oil makes a very attractive polymer flooding target, especially given the high permeability of the unconsolidated formation.

These differences demonstrate how the predictive capacity of a simulator is limited by the information that the simulator has “seen”. The change in injected fluid mobility caused Model A, a valid history matched model for waterflooding, to be invalid for polymer flooding. This clearly demonstrates the stipulations of Flora’s Rule, requiring a change in time to make the model valid again (Ibiam et al. 2021). Then, the mechanism motivating the water surge in J-28 (and anticipated to occur in J-27) invalidated Model B, again reflecting that a change in flow behavior in the reservoir requires recalibration of the simulation model. It is worth noting that even if a different history match approach were pursued (i.e. relative permeability pseudoization), these key events would still need to be “seen” and calibrated towards. This would likely require updating the history match during the project lifecycle, leading to revisions in the production forecasts.

This work shows that an unconsolidated heavy oil reservoir subjected to multiple injected fluids is a very dynamic system that can be difficult to capture through reservoir simulation. Certainly, lengthy amounts of production data are necessary to achieve confident forecasts for such a system. Thus, a key takeaway from this work is that while reservoir simulation can be useful for scoping the potential of EOR techniques, caution should be used in drawing conclusions. A model that has been calibrated for a waterflood may not capture the full benefits of a polymer flood, leading to pessimistic assessments. In turn, this could cause value-adding EOR projects to be overlooked. Small scale field pilots cannot be replaced for providing the real-world data needed to make assessments for potential full-field application.

Future work will evaluate the economic success of the polymer flood field pilot through incremental economic analysis. The three models presented in this study will be subjected to this analysis to determine the economic impact of the changing reservoir flow conditions. The incremental economic analysis will then be used in conjunction with a simulation sensitivity analysis to provide recommendations for the future operation of this pilot and the design of future polymer floods.
2.6 Conclusions
A reservoir simulation model has been successfully calibrated to predict production from the ongoing ANS polymer flood field pilot to enhance the recovery of heavy oils. The history matching process and resulting production forecasts yield the following insights:

1. Transmissibility contrasts had to be introduced to the model to simulate early water breakthrough during waterflooding of heavy oil, which forces the viscous fingering behavior believed to motivate the early water breakthrough.
2. These transmissibility contrasts had to be reduced to simulate the restoration of injection conformance from tertiary polymer flooding.
3. Transmissibility contrasts were reintroduced to replicate a water surge event observed during polymer flooding in one of the production wells, which may represent fracture overextension resulting from polymer injection in the unconsolidated formation.
4. Oil recovery of polymer flooding is sensitive to the occurrence and timing of a similar water cut surge event in the other producing well (i.e., J-27). If the event can be delayed or avoided, oil recovery will increase.
5. Machine-assisted history matching procedures allowed many parameters to be varied independently, producing a more reasonable calibrated model than manual procedures. This is gauged by the reduced frequency of transmissibility changes in time and the simultaneous matching of producing water cut, produced polymer concentration, and BHP.
6. The proper definition of retention in the simulation model, incorporating a retention tailing effect, was useful to match the producing water cut and produced polymer concentration simultaneously.
7. All calibrated simulation models predict significantly higher oil recovery from polymer flooding compared to waterflooding alone.
8. A simulation model calibrated for waterflooding may not accurately capture the full benefit of an EOR strategy such as polymer flooding.
9. The predictive capacity of a simulation model is limited by the flow behavior captured in the production history. Thus, a previously calibrated simulation model may no longer be valid for predictions if events occur to change this flow behavior.
2.7 Acknowledgements

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2.8 Nomenclature

\[
\begin{align*}
\text{ANS} & = \text{Alaska North Slope} \\
\text{BHP} & = \text{Bottomhole Pressure} \\
\text{cp} & = \text{centipoise} \\
\text{EOR} & = \text{Enhanced Oil Recovery} \\
\text{ft} & = \text{feet} \\
\text{GOR} & = \text{Gas-Oil Ratio} \\
\text{HM} & = \text{History Match} \\
\text{k}_r & = \text{relative permeability} \\
\text{k}_{ro} & = \text{oil relative permeability} \\
\text{k}_{rw} & = \text{water relative permeability} \\
\text{mD} & = \text{millidarcy} \\
\text{OOIP} & = \text{Original Oil in Place}
\end{align*}
\]
**ppm** = parts per million

**psi** = pounds per square inch

**PVT** = Pressure Volume Temperature

**STB/D** = Stock Tank Barrels per Day

**S_w** = water saturation

**VR-WAG** = Viscosity-Reducing Water Alternating Gas

**°F** = degrees Fahrenheit

### 2.9 References


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2.10 Figures

Figure 2.1 ANS viscous and heavy oil resource. The blue shading represents viscous oil, with the darker blue indicating areas under current development. The purple outline represents heavy oil, not yet developed (Paskvan et al. 2016).

Figure 2.2 ANS polymer flood field pilot reservoir boundaries, with injector-producer well patterns (Dandekar et al. 2019).
Figure 2.3 Plan view of the reservoir simulation model.

Figure 2.4 Water-oil relative permeability curves measured in lab and calibrated during history matching.
Figure 2.5 Polymer solution viscosity as a function of shear rate and polymer concentration. From Wang et al. (2021).

Figure 2.6 Polymer retention as a function of polymer concentration.
Figure 2.7 Actual producing oil rate and water cut for wells (a) J-27 and (b) J-28. Switch from waterflooding to polymer flooding indicated with red vertical line.
Figure 2.8 Actual injecting water rate for wells (a) J-23A and (b) J-24A. Switch from waterflooding to polymer flooding indicated with red vertical line.
Figure 2.9 Location of high transmissibility strips (colored) in the model.

Figure 2.10 Location of inter-strip-blocks (colored).
Figure 2.11 Water cut simulation results for (a) J-27 and (b) J-28. “Reduce Contrast” and “Increase Contrast” refers to decreasing and increasing the strip transmissibility in time for the appropriate model cases.
Figure 2.12 Predicted oil recovery for each forecasted simulation case. The best matched model forecast for each case is indicated with a solid line, the most optimistic forecast for each case is indicated with a dashed line, and the most pessimistic forecast for each case is indicated with a dotted line.

Figure 2.13 High transmissibility strip arrangement during maturation of polymer flood through early 2021.
Figure 2.14 Produced polymer concentration simulation results for (a) J-27 and (b) J-28.

Figure 2.15 High transmissibility strip arrangement reflecting J-28 water surge in mid-2021.
Figure 2.16 BHP full history match for well (a) J-23A, (b) J-24A, (c) J-27, and (d) J-28.
Figure 2.16, continued. BHP full history match for well (a) J-23A, (b) J-24A, (c) J-27, and (d) J-28.
Figure 2.17 Oil recovery versus pore volumes injected for the base case polymer flood forecast and waterflood forecast. Note that both axes are given as percentages.

Figure 2.18 Producing water cut history match for (a) J-27 and (b) J-28, with and without the retention tailing effect.
Figure 2.19 Produced polymer concentration history match for (a) J-27 and (b) J-28, with and without the retention tailing effect.

Figure 2.20 Simulated flow streamlines for historic waterflood, forecasted waterflood, and polymer flood.
2.11 Tables

<table>
<thead>
<tr>
<th>Layer</th>
<th>Thickness (ft)</th>
<th>Horizontal Permeability (mD)</th>
<th>Porosity (%)</th>
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<td>2,000</td>
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**Table 2.1 Reservoir model properties by layer**

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<th>Value</th>
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<td>Oil viscosity (cp)</td>
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**Table 2.2 Additional reservoir model properties**

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<th>Well</th>
<th>Liquid Rate (STB/D)</th>
<th>BHP (psi)</th>
<th>Poly. Conc. (ppm)</th>
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<td>J-23A</td>
<td>1,500</td>
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<tr>
<td>J-24A</td>
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<td>J-27</td>
<td>1,000</td>
<td>800</td>
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<tr>
<td>J-28</td>
<td>1,000</td>
<td>650</td>
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**Table 2.3 Constraints for polymer flood forecasting**

<table>
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<th>Liquid Rate (STB/D)</th>
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<tr>
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<td>J-28</td>
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**Table 2.4 Constraints for waterflood forecasting**
Table 2.5 Expected ultimate oil recovery of polymer flooding using the Full Model with variable timing for anticipated water surge event in J-27.

<table>
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<tr>
<th>J-27 Surge Timing</th>
<th>Oil Recovery (%OOIP, 2050)</th>
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<td>34.7%</td>
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<tr>
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<tr>
<td>Jan. 2022</td>
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<td>Sept. 2021</td>
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### 2.12 Appendix

#### Table A-1 History matching parameters.

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<th>Parameter</th>
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<th>Minimum</th>
<th>Maximum</th>
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**Relative Permeability**

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**Inter-strip Block Transmissibility Multipliers**

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**Strip Transmissibility Multipliers, Waterflood & Early Polymer Flood**

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Table A-1 History matching parameters (continued).

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Chapter 3  Economic Evaluation of Polymer Flood Field Pilot

3.1 Abstract
Since August 2018, a polymer flooding field pilot has been underway in an unconsolidated heavy oil reservoir on the Alaska North Slope. Previously, a reservoir simulation model was constructed and calibrated to predict the oil recovery of the field test; it demonstrated that polymer flooding is technically feasible to significantly improve oil recovery from heavy oil reservoirs on the Alaska North Slope. However, the economic performance of the pilot, critical to determining its success, has not been investigated, which is another key metric used in assessing the overall performance of the field pilot. Therefore, this study focuses on evaluating the project’s economic performance by integrating the calibrated simulation model with an economic model. The investigation results demonstrate that the project value remains profitable for all polymer flood scenarios. Thus, the use of polymer flooding over waterflooding is attractive. However, the predicted value changes meaningfully between the scenarios, emphasizing that a simulation model should be taken as a “living forecast”. Subsequently, an economic sensitivity analysis is conducted to provide recommendations for continued operation of the ongoing field pilot and future polymer flood designs. The results indicate that a higher polymer concentration can be injected due to the development of fractures in the pilot reservoir. The throughput rate should remain high without exceeding operating constraints. A calculated point-forward polymer utilization parameter indicates a decreasing efficiency of the polymer flood at later times in the pattern life. Future projects will benefit from starting polymer injection earlier in the pattern life. A pattern with tighter horizontal well spacing will observe a greater incremental benefit from polymer flooding. This case study provides important insight for the broader discussion of polymer flood design from the economic perspective. It illustrates how expectations for performance may change as additional data is collected. It also formalizes the concept of "point-forward utilization" to evaluate the incremental efficiency of additional chemical injection.

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2 This chapter is co-authored by Keith, C. D., Wang, X., Zhang, Y. et al., and is an article in-prep for publishing in the 2022 Society of Petroleum Engineers Annual Technical Conference and Exhibition as well as for publishing in a peer-reviewed Society of Petroleum Engineers Journal.
3.2 Introduction

Globally, heavy oil resources make up a significant portion of the world’s oil reserve, up to 25% by some estimates (Ibiam et al. 2021). Often, these heavy oils are associated with high-permeability unconsolidated sand reservoirs (Mai and Kantzas 2008). Waterflooding has been applied in reservoirs with oil viscosity as high as 10,000 cp (Luo et al. 2017). However, heavy oil recovery with waterflooding is often less than 20% (Gao 2011) since displacement efficiency is hampered by viscous fingering effects stemming from an unfavorable mobility ratio (Mai and Kantzas 2008). In addition, sweep efficiency can be degraded due to channeling in heterogeneous formations (Luo et al. 2017).

A significant viscous and heavy oil resource has been found on the Alaska North Slope (ANS), mainly located within the existing Kuparuk River Unit, Prudhoe Bay Unit, Milne Point Unit, and Nikaitchuq Unit, as shown in Fig. 3.1 (Paskvan et al. 2016). These resources are contained in the poorly-consolidated shallow-marine Schrader Bluff and non-marine Prince Creek formations (Decker 2007). The Schrader Bluff and West Sak reservoirs in the Schrader Bluff formation may contain over 16 billion barrels of viscous and heavy oil, with an additional 10 billion barrels of heavy oil in the Ugnu reservoir of the Prince Creek Formation (Bidinginger and Dillon 1995; Decker 2007; Paskvan et al. 2016). Despite this significant resource, as of 2018, viscous oil makes up only 6% of Alaska’s oil production (Garg et al. 2018).

Field-scale production of ANS viscous oil resources began in the late 1990s (Targac et al. 2005), with production focused on favorable low viscosity (< 100 cp) portions of the reservoir (Paskvan et al. 2016). However, waterflood recoveries frequently fall below 20%, yielding only 150 million barrels of produced oil as of 2016 (Paskvan et al. 2016). Furthermore, considerable resources remain in higher oil viscosity portions of the reservoirs (Paskvan et al. 2016). Thus, growth potential in Alaska’s viscous and heavy oil production can be achieved by improving recovery from existing patterns and unlocking hitherto untargeted higher viscosity tranches.

Polymer flooding has become a popular enhanced oil recovery method worldwide (Seright 2017). Polymer flooding reduces the mobility ratio between the injected fluid and displaced viscous oil, improving the displacement efficiency (Luo et al. 2017). Recently, injectivity improvements using horizontal injecting wells have allowed successful polymer projects to occur in patterns with live oil viscosities as high as 10,000 cp (Delamaide 2018). Furthermore, polymer flooding has a minimal environmental impact, making it an even more attractive option for
improving oil recovery (Fabbri et al. 2014). This is especially true on ANS, where the fragile arctic environment could be particularly harmed by other heavy oil recovery techniques such as thermal recovery methods.

With these ideas in mind, the first ever polymer flood field pilot to enhance the recovery of heavy oils on the Alaska North Slope began in 2018. The pilot is implemented in an isolated region of the Schrader Bluff Nb sand within the J-Pad of the Milne Point Unit (Fig. 3.2). Reservoir properties are given in Table 3.1. Patterns include two horizontal producing wells, J-27 and J-28, supported by two horizontal injecting wells, J-23A and J-24A. Production began with waterflooding in 2016, followed by tertiary polymer flooding on August 28, 2018. Additional details on the field pilot can be found in the literature (Ning et al. 2019, 2020; Dandekar et al. 2019, 2020). The performance of the pilot actually exceeded the expectations: after implementing polymer flooding, the producing oil rate has remained above the predicted oil rate for waterflooding, with dramatic water cut reductions observed.

A simulation model calibrated for this ANS polymer flood field pilot was produced by Keith et al. (2022) using machine-assisted workflows. The main history matching approach involved introducing and then modifying horizontal transmissibility contrast to replicate the flow behaviors motivating observed production trends. Specifically, transmissibility contrast was introduced to the simulation model during the waterflood period to force viscous fingering behaviors. The contrast was subsequently reduced during polymer flooding to replicate the dampening of these fingering effects with the lower mobility injected polymer solution. Later, transmissibility contrasts were reinstated to replicate reduced injection conformance from fracture overextension. Although these different flow behaviors had a notable impact on the oil production forecasts, in all cases, the oil recovery predicted for polymer flooding was significantly higher than that predicted for waterflooding. As such, the polymer flood pilot has been deemed a technical success. Refer to Chapter 2 for additional details.

The previous simulation study indicates that the polymer flood field pilot is technically successful in increasing and accelerating the oil recovery. However, another key question is whether the additional investment necessary to implement the polymer flood is worth the enhanced oil recovery benefit (Delamaide 2018).

Some studies have examined the economic evaluation and optimization of polymer floods. Clemens et al. (2011) used streamline simulation to optimize the polymer flood design at the
pattern level based on polymer utilization factors. Choudhuri et al. (2015) performed similar work on a different oil field, using a history-matched streamline simulation model to identify the most and least efficient polymer flood patterns based on the calculated polymer utilization factor. Mogollón et al. (2016) coupled a simulation model with an economic model in an optimization software to scope the potential for polymer flood success in a mature heavy oil reservoir. Sieberer et al. (2017) examined the sensitivity of the economic value of polymer flooding to different design parameters at the full-field scale. Anand et al. (2018) also history-matched a simulation model to polymer flood performance and then used it to understand pattern performance via the polymer utilization factor. Hidayat and ALMolhem (2019) used a synthetic reservoir simulation model to test the oil recovery sensitivity to polymer flood properties and then optimize the polymer flood design for economic value. Ibiam et al. (2021) produced a range of history-matched simulation models spanning a breadth of geologic uncertainties; they optimized the polymer flood design for this range of models and demonstrated that even if the optimal polymer flood design was mismatched to the geologic uncertainty, the economic value still exceeds waterflooding.

Thus, there is a sizeable body of literature on polymer flooding economics and optimization. Our work seeks to extend these concepts to the ANS polymer flood pilot, continuing the dialogue with this unique case study. Furthermore, we propose a novel point-forward polymer utilization parameter that builds on the pattern utility plot developed by Choudhuri et al. (2015) in order to isolate the efficiency of individual periods of polymer injection – information that is obscured in traditional cumulative utilization factors (Sieberer et al. 2017).

This work seeks to evaluate the economic success of the first ever polymer flood field pilot to enhance the recovery of heavy oils on ANS. First, the reservoir simulation models produced by Keith et al. (2022) are used to produce recovery forecasts for both polymer flooding and waterflooding. Next, these forecasts are input into a custom-built incremental economic modeling tool, which evaluates the benefit of polymer flooding above waterflooding in these patterns. Subsequently, the simulation model and the economic model are used in conjunction to evaluate the sensitivity of the polymer flood performance to various design parameters, including the injected polymer concentration, throughput rate, polymer injection duration, polymer injection initiation time, and well spacing. Finally, recommendations are provided for the continued operation of this polymer flood pilot as well as the design of future polymer flood projects.
3.3 Methodology

3.3.1 Production Forecasting
In previous work, our team calibrated a range of reservoir simulation models to the production data from this polymer flood field pilot (Keith et al. 2022). Three simulation model cases were developed: Model A was history-matched only through the waterflood and early polymer flood period; Model B was history-matched through the maturation of the polymer flood; and the Full Model matched all current production data, including a water cut surge observed in well J-28 related to a fracturing mechanism. The top 24 history-matched models from each case are advanced to production forecasting. In particular, the Full Model base forecast incorporated an anticipated surge in well J-27 at the start of 2022. The methods used to produce these forecasts are reviewed as follows.

Each well is constrained by its current liquid rate and bottomhole pressure (BHP). The simulator attempts to achieve the liquid rate constraint unless the BHP constraint is exceeded, in which case the well runs on the BHP constraint. Forecasting for polymer flooding begins in mid-September 2021 and ends in June 2050. Waterflood-only forecasts are pursued to demonstrate production expectations had the polymer flood not been implemented. These waterflood forecasts start from the actual date when polymer flooding began (August 28th 2018) and again extend until June 2050. The constraints for polymer flood forecasting are shown in Table 3.2, and the constraints for waterflood forecasting are shown in Table 3.3. These constraints are based on recent well performance under the given injection strategy. Because all of the top 24 history-matched models for each case are run on the same constraints, the variability between these models can be interpreted as an injectivity and deliverability uncertainty test (Keith et al. 2022).

3.3.2 Economic Analysis
An economic modeling tool was custom built to analyze the incremental cost and benefit of polymer flooding compared to waterflooding. In other words, the tool evaluates the economic implications of the decision to switch from waterflooding to polymer flooding. To emphasize, it does not indicate whether the broader decision to produce from these patterns is economic; it only tells us if the polymer flood is more economic than waterflooding in this area. This choice provides for the focused analysis of the polymer flood campaign, allowing several simplifying assumptions to be made to reduce the number of uncertain parameters incurred during analysis.
Oil production from the pattern under both polymer flooding and waterflooding and polymer mass injected are determined by simulation and input into the economic modeling tool. The best-matched waterflood simulation model is used to provide the waterflood oil production forecasts for the incremental economic analysis. The best-matched \( P_{\text{best}} \), most optimistic \( P_{\text{high}} \), and most pessimistic \( P_{\text{low}} \) forecasts from the top 24 history-matched models for simulation Model A, Model B, and the Full Model are input into the economic modeling tool for evaluation.

Additional cost and price input parameters are supplied in Table 3.4. The revenue in the economic modeling tool is calculated from the incremental monthly oil production assuming a conservative base oil price of $40 per barrel. The mass of polymer injected can be considered one form of operating expenditure (OPEX) for the pattern; a base cost of $1.50 per pound is assumed for the acquisition and transport of the polymer. An additional form of OPEX is the incremental maintenance and surveillance required to implement a polymer flood compared to a waterflood; this value is approximated at $100,000 per year. Finally, the additional capital expenditure (CAPEX) incurred to acquire and install the polymer injection unit is approximately valued at $3,000,000 and expensed at once in August 2018. Cash flows are taken at the end of the month they occur and are discounted back to August 2018. Similar to Ibiam et al. (2021), a discount rate of 10% per annum is assumed.

The monthly incremental revenue for month \( n \) is calculated as,

\[
\text{Revenue}_n = (V_{o,p,n} - V_{o,w,n}) \times C_o
\]

where \( V_{o,p,n} \) is the volume of oil produced under polymer flooding for month \( n \), \( V_{o,w,n} \) is the volume of oil produced under waterflooding for month \( n \), and \( C_o \) is the oil price.

The monthly incremental OPEX can be calculated as,

\[
\text{OPEX}_n = M_{p,n} \times C_p + C_m
\]

where \( M_{p,n} \) is the mass of polymer injected in month \( n \), \( C_p \) represents the cost of polymer acquisition and transport, and \( C_m \) represents the cost of additional maintenance and surveillance incurred by polymer flooding.

The CAPEX is determined for each month as,

\[
\text{CAPEX}_n = \begin{cases} C_f, & n = 0 \\ 0, & n \neq 0 \end{cases}
\]

where \( C_f \) is the cost of polymer facility acquisition and installation.
The economic modeling tool calculates three parameters: the Net Present Value (NPV), the Discounted Profit to Investment Ratio (PI Ratio), and the Development Cost. To emphasize, all three of these parameters are calculated based on the incremental economics of the polymer flood strategy over a waterflood base case.

NPV is calculated as

\[ NPV = \sum_{n=0}^{N} BTCF_n \left( \frac{1}{1+i/12} \right)^n \]  

where \( i \) is the discount rate per annum and \( N \) is the maximum number of prediction months. The NPV gives an indication of the overall profit, in today’s dollars, obtained by implementing the polymer flood. Note that taxes and royalties are not included in the economic analysis as these parameters are confidential for the operators and not pertinent to this analysis. As such, this NPV is more accurately referred to as a cumulative discounted before tax cash flow; the term NPV will be used in this work for brevity and familiarity.

The Discounted PI Ratio, which gives an indication of how much profit is made for each dollar that is spent, is calculated as,

\[ PI \ Ratio = \frac{NPV}{\sum_{n=0}^{N} OPEX_n \left( \frac{1}{1+i/12} \right)^n + CAPEX_n} \]  

The Development Cost indicates how much money must be spent to produce each additional barrel of incremental oil. It is calculated as the sum of the undiscounted cumulative CAPEX and OPEX divided by the produced oil volume,

\[ Dev. \ Cost = \frac{\sum_{n=0}^{N} OPEX_n + CAPEX_n}{\sum_{n=0}^{N} V_{o,p,n} - V_{o,w,n}} \]  

Additionally, to evaluate the efficiency of the injected polymer independent of price parameters, the polymer utilization factor (PUF) is calculated as a function of time (Sieberer et al. 2017),

\[ PUF(t) = \frac{M_p(t)}{V_{o,p}(t) - V_{o,w}(t)} \]  

where \( V_{o,p} \) is the cumulative volume of oil produced under polymer flooding at time \( t \), \( V_{o,w} \) is the cumulative volume of oil produced under waterflooding at time \( t \), and \( M_p \) is the cumulative mass
of polymer injected at time $t$. This indicates how many pounds of polymer were injected per barrel of incremental oil produced (Delamaide 2016; AlSofi et al. 2017; Anand et al. 2018).

Finally, to indicate the sensitivity of our project evaluation to uncertain economic parameters, the economic analysis for the best-matched Full Model is repeated for more optimistic and conservative estimates of the oil price, polymer acquisition and transport cost, and polymer facility acquisition and installation cost. These conservative and optimistic input economic parameter estimates are provided in Table 3.4.

### 3.3.3 Design Sensitivity Analysis

A sensitivity analysis with regard to design parameters is conducted to optimize the current polymer flood pilot as well as provide guidance for future polymer flood projects. The best-matched Full Model is employed to generate production forecasts for these varying design parameters, and the incremental economic modeling tool is used to determine the economic implication of varying these parameters. Tested design parameters include the injected polymer concentration, throughput rate, polymer injection duration, polymer flood start time, and well spacing.

#### 3.3.3.1 Injected Polymer Concentration

The injected polymer concentration is varied in the simulation model from 300 ppm to 2,700 ppm in 300 ppm increments. The polymer solution viscosity is specified as a function of shear rate at each different concentration. Forecasts begin from the end of the history-matched period, in mid-September 2021. Thus, this test represents a point-forward sensitivity analysis. It is assumed that the transmissibility multiplier configuration remains independent of the polymer concentration. Constraints are the same as given in Table 3.2.

#### 3.3.3.2 Throughput Rate

In this sensitivity test, the total pattern injection and production target rate is varied between 1,000 and 4,000 barrels per day (BPD). The allocation of rates to each well remains the same: J-23A receives 75% of the total pattern injection rate while J-27 receives 50% of the total pattern production rate. The total pattern injection rate and production rate are kept equal to maintain a voidage replacement ratio of unity and thus avoid matrix bypass events (Paskvan et al. 2016). This
total rate is referred to as the throughput rate. It is also important to note that these rates are only the target rate that the wells will try to achieve; if the BHP constraint would be exceeded, then these rates will not be reached. BHP constraints and the injected polymer concentration remain the same as in Table 3.2. Forecasting begins in mid-September 2021, so this study represents a point-forward sensitivity analysis.

3.3.3.3 Polymer Injection Duration

The decision on whether to continue to inject polymer at any given time is based on the expected efficiency of polymer flooding from that time onward, along with the prevailing economic conditions (Seright 2017). While we cannot forecast the prevailing economic conditions with much certainty, we can demonstrate how the polymer efficiency decreases with time and to what extent.

The traditional polymer utilization factor includes all cumulative polymer injection and cumulative incremental oil production (Sieberer et al. 2017). While useful, the cumulative nature of this parameter makes it challenging to evaluate the decision of when to stop polymer injection based on point-forward benefit expectations (Choudhuri et al. 2015). Choudhuri et al. (2015) provided a workflow to evaluate the utility factor of continued polymer injection. Their technique resulted in a pattern utility plot that can be used to optimize the time to switch a polymer flood back to waterflooding. Based on this approach, we propose a point-forward polymer utilization (PFPU) parameter that only considers the cost and benefit of an additional time increment of polymer injection. PFPU is given as,

\[ PFPU = \frac{M_{p,y+\Delta y} - M_{p,y}}{V_{o,y+\Delta y} - V_{o,y}} \]  

(3.9)

where the subscript \( y \) represents the year at which the decision to switch back to waterflooding is considered, and the subscript \( \Delta y \) indicates the considered duration of additional polymer injection in years. Note that the cumulative polymer injection and cumulative oil produced are both time series. Hence, PFPU is a time series as well with a “checkmark” shape similar to the typical polymer utilization plot.

To apply Equation 3.9, separate forecast cases are simulated featuring a switch from polymer injection to water injection in 2025, 2030, 2035, 2040, 2045, 2050, 2055, 2060, 2065, and 2075. The same constraints from Table 3.2 are used during polymer flooding. When the switch occurs, we expect the water to finger through the polymer bank (Fabbri et al. 2015; Seright 2017;
Anand et al. 2018). As such, the strip transmissibility arrangement from the history-matched waterflood period is re-implemented in the simulator when the switch back to waterflooding occurs. The well constraints are also changed at the switch to waterflooding to those given in Table 3.3. Five-year intervals \((\Delta y = 5\) years\) are used for the switch time between the various cases. The forecast is carried out to 2075 so that we can better observe the behavior of this exercise. This work calculates the PFPU time series for each case by comparing subsequent switch time cases. The minimum PFPU achieved for each case is used for evaluation.

3.3.3.4 Polymer Injection Start Time

A key design question for future heavy oil projects is whether it is more beneficial to start with waterflooding and then pursue polymer flooding as a tertiary recovery method or initiate polymer flooding immediately (Delamaide 2016). We seek to use our calibrated simulation model to test this question.

Because this design question represents a decision made at the start of the pattern life, the rate and pressure data from the historical period is not useful for evaluation. Thus, we use the simulation model entirely in forecasting and start the forecasts at the beginning of the pattern lives (June 2016). The wells are run on the appropriate liquid rate and BHP constraints for waterflooding (Table 3.3) and/or polymer flooding (Table 3.2). The Model A transmissibility contrast is implemented for the entire waterflood period, the Model B contrast is implemented for the first three years of polymer flooding, and the Full Model contrast is implemented afterward in anticipation of fracture overextension. Finally, we assume an 1,800 ppm polymer injection concentration for two years, followed by 1,200 ppm thereafter.

Cases are tested for polymer flooding only, waterflooding only, and switching from waterflooding to polymer flooding in January 2017 (6 months waterflooding), June 2017 (1 year waterflooding), June 2018 (2 years waterflooding), September 2018 (similar to what was actually performed), June 2019 (3 years waterflooding), June 2020 (4 years waterflooding), and June 2021 (5 years waterflooding).

The economic modeling tool is used to discount cash flows back to June 2016. It is assumed that the CAPEX for polymer facility acquisition and installation occurs in the same month that polymer flooding is initiated.
3.3.3.5 Well Spacing

The influence of well spacing under both waterflooding and polymer flooding is investigated. To do this, we modify the arrangement of the horizontal wells in the simulation model. We include one horizontal producing well (J-27) supported equally on both sides by horizontal injecting wells (J-23A and J-24A), representing a confined pattern (Delamaide 2018). The BHP constraints and the producer liquid rate constraint for polymer flooding and waterflooding are the same as given in Table 3.2 and Table 3.3, respectively. The rate constraint for each injector is modified to equal 50% of the producer rate constraint. The well spacing of the actual pilot is about 1,200 ft; this is varied in these sensitivity tests to 500 ft, 800 ft, 1,000 ft, and 1,500 ft.

Two cases are run for each investigated well spacing: waterflood and polymer flood. The polymer flood assumes no preceding waterflood (Delaplace et al. 2013). Since parameters are being changed from the historic period, the simulation is run on forecasting alone starting in June 2016. The arrangement is compressed or expanded as appropriate to fit the different well spacings. We assume the transmissibility contrast is independent of the well spacing. Thus, the same transmissibility contrasts between well pairs are utilized. For waterflood cases, Model A transmissibility arrangements are used. For polymer flood cases, Model B transmissibility contrasts are utilized. We assume a fracturing event occurs after three years for the polymer flood cases, introducing the full model strip transmissibility arrangement. Note again that this assumes that the timing of the fracturing is independent of well spacing. Finally, for polymer flood cases, we assume two years of injecting at 1,800 ppm polymer concentration, followed by 1,200 ppm thereafter.

The economic modeling tool is modified to discount cash flows back to June 2016. In addition, the waterflood and polymer flood forecasts for each well spacing tested are supplied for the incremental analysis. It is assumed that the CAPEX for polymer facility acquisition and installation occurred at the start of June 2016.

3.4 Results

3.4.1 Production Forecasting

The oil recovery forecasts produced by Model A, Model B, the Full Model, and waterflooding alone are compared in Fig. 3.3 (Keith et al. 2022). As can be seen, Model A produces the most
pessimistic results, Model B is the most optimistic, and the Full Model (including the anticipated water surge in J-27 at the start of 2022) predicts an intermediate oil recovery. Importantly, all three polymer flooding models predict significantly higher oil production under polymer flooding than waterflooding alone.

### 3.4.2 Economic Analysis

The polymer utilization for the best history-matched ($P_{best}$), most optimistic ($P_{high}$), and most pessimistic ($P_{low}$) of the top 24 history-matched models for the Full Model, Model A, and Model B is shown in Figure 3.4. Model B predicts the most efficient polymer flood (lowest polymer utilization), Model A predicts the least efficient polymer flood, and the Full Model remains intermediate. The Full Model and Model B reveal the characteristic checkmark shape of this time series plot, with some deviations due to normal operational inefficiencies. The polymer utilization factor first declines to a minimum value as the maximum oil bank response to polymer injection develops (Clemens et al. 2011; Anand et al. 2018). Model B predicts this peak response occurring around 2023, while the Full Model predicts an earlier maximum response around 2022. After this peak oil production, the incremental oil gain declines with time, causing the polymer utilization to rise again (Clemens et al. 2011; Anand et al. 2018). Note that Model A deviates from this characteristic shape because it does not capture the full historic benefit of the polymer flood (Keith et al. 2022).

The economic performance (incremental to waterflood) for the best history-matched ($P_{best}$), most optimistic ($P_{high}$), and most pessimistic ($P_{low}$) of the top 24 history-matched models for the Full Model, Model A, and Model B is shown in Table 3.5. Note that a higher NPV indicates a greater project value while a higher PI ratio and low development cost indicate a more efficient investment. Similar to the oil recovery evaluation, we see that Model A produces the most pessimistic results, Model B is the most optimistic, and the Full Model is intermediate. Thus, the best-matched Full Model simulation, hereafter referred to as the base polymer forecast, predicts that the polymer flood pilot will generate a present value of about $42.9 million during the entire 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.

Finally, the base polymer forecast is subjected to an economic parameter sensitivity test. Figure 3.5 shows how increasing or decreasing the oil price, polymer acquisition and transport cost,
and polymer facility acquisition and installation cost influences the NPV estimate, as a percent deviation from the base case ($42.9 million). The price ranges of these economic parameters are listed in Table 3.4. Because oil price is the most uncertain parameter, a wider range of values were tested ($20/bbl to $80/bbl). The economic analysis is highly sensitive to the oil price. On the other hand, the cost parameters are shown to be much less sensitive, indicating that inaccuracies in our estimates of these costs may not have a significant influence on our comparative economic analysis.

### 3.4.3 Design Sensitivity Analysis

#### 3.4.3.1 Injected Polymer Concentration

The oil recovery factor predictions for each tested polymer concentration (along with waterflooding alone) are plotted in Fig. 3.6. For all cases tested, the polymer flood performs superior to waterflooding alone, achieving higher oil recoveries. In general, increasing the injected polymer concentration up to about 2,100 ppm increases the oil recovery. However, for polymer concentrations above 2,100 ppm, the decrease in injectivity limits the injecting rate. The producing wells are thus less supported and produce less oil at these higher injected polymer concentrations, leading to a decline in the oil recovery factor.

The forecasted polymer utilization for each injected polymer concentration is shown in Fig. 3.7. In general, and particularly in earlier times, increasing the polymer concentration increases the polymer utilization. This indicates that the additional polymer mass injected with higher concentrations provides diminishing oil production benefit. However, for very high polymer concentrations (greater than 1,800 ppm), we see that the polymer utilization is less in late times compared to lower polymer concentrations. This is due to injectivity issues: for very high polymer concentrations, we end up injecting less cumulative polymer mass in later times because we cannot inject the same volume of solution. Therefore, the lower injected polymer mass leads to a lower polymer utilization.

The incremental NPV is plotted against the injected polymer concentration in Fig. 3.8. As expected, the incremental NPV follows very closely with the incremental recovery factor since the more valuable oil tends to dominate the NPV parameter. For increasing concentrations from 300 ppm to 2,100 ppm, the oil production and NPV increase. For concentrations greater than 2,100
ppm, the injectivity becomes too low, leading to less oil production and a lower NPV. From this, a higher injected polymer concentration (up to 2,100 ppm) would be recommended.

3.4.3.2 Throughput Rate

The oil recovery factor for tested throughput rates is plotted in Fig. 3.9. In general, increasing the throughput rate results in more oil production and thus a higher recovery factor. However, the simulation indicates that the reservoir is unable to support a throughput rate much higher than 3,500 BPD without encountering the BHP constraints in the wells. Thus, the 4,000 BPD case tested is not much improved from the 3,500 BPD case.

The forecasted polymer utilization for varying throughput rates is shown in Fig. 3.10. The clearest trend is observed at later times, where larger throughput rates feature a higher polymer utilization. This indicates that the additional polymer mass injected at higher throughput rates came with diminishing incremental oil benefits.

The incremental NPV is plotted against the throughput rate in Fig. 3.11. As expected, the incremental NPV follows very closely with the incremental recovery factor since the more valuable oil will tend to dominate the NPV parameter. Since the oil recovery improves with increased throughput rate, so too does the NPV. However, a limit to the improvement is reached at about 3,500 BPD due to BHP constraints.

3.4.3.3 Polymer Injection Duration

The recovery factor for each simulated case is shown in Fig. 3.12. As can be seen, when the switch from polymer flooding to waterflooding occurs, the recovery factor flattens substantially.

The minimum PFPU value is plotted versus the switch time in Fig. 3.13, directly showing how each additional increment of polymer injection is less efficient. For example, in 2025, it only takes about 1.5 pounds of polymer to produce an additional barrel of oil, whereas in 2050, it takes about 6 pounds.

3.4.3.4 Polymer Injection Start Time

The oil production rate for the tested polymer flood start times is shown in Fig. 3.14. For the first 5 months, waterflooding is capable of achieving higher oil rates than the polymer flood since higher throughput rates are possible with the improved injectivity of water. After that,
however, a rapid decline in oil rate is observed during waterflooding due to viscous fingering effects. When polymer flooding is implemented after a waterflood, the predicted oil rate increases and then stabilizes for about 2 – 4 years before declining. The duration of the stabilized oil rate period increases for earlier polymer flood start-times. Furthermore, the oil rate during polymer flooding declines much more gradually than during waterflooding, even with the fracturing event occurring.

**Fig. 3.15** shows the oil recovery factor for the tested cases. All of the polymer flooding cases converge to similar expected ultimate recovery (EUR) factors, indicating that the polymer flood startup time does not influence the ultimate oil recovery but does influence how quickly that oil is recovered.

The incremental NPV is plotted against the start time for polymer injection in **Fig. 3.16**. We observe that it is generally better to start the polymer flood earlier to achieve the higher sustained oil rates sooner and for longer. However, this test also indicates that it is better to start with a brief period of waterflooding rather than starting with polymer flooding only. This is due to the higher sustained throughput rate during the early waterflood period.

### 3.4.3.5 Well Spacing

The oil recovery factor predictions for both polymer flooding and waterflooding for various well spacing are shown in **Fig. 3.17**. Note that the recovery factor is based on the oil volume contained between the two injecting wells. For polymer flooding and waterflooding, decreasing the well spacing increases the EUR and the rapidity with which it is obtained. The polymer flood particularly shows a rate dependence since increasing the well spacing decreases the inter-well pressure gradient and dramatically reduces the injectivity. However, in all cases, the polymer flood greatly outperforms the waterflood. Therefore, polymer flooding is preferred over waterflooding within the tested bounds, regardless of well spacing for this heavy oil reservoir.

The polymer utilization is plotted for each well spacing in **Fig. 3.18**. In early times, larger well spacing leads to higher polymer utilization values and a delay in reaching the minimum value. This is because the larger spacing causes greater injectivity issues and a delay in seeing pressure support at the producers. However, at later times, larger well spacing leads to lower polymer utilization values. This is likely because the additional oil volume contained within the larger spacing provides greater benefit for the extended polymer injection. So, we can conclude that a
tighter well spacing yields a more efficient polymer flood due to the improved pressure support and that the maximum value from the patterns will be realized sooner.

Given identical reservoirs with wells that have already been drilled, an important question is whether polymer injection should be prioritized for patterns with tighter well spacing or larger well spacing. To examine this, we consider the difference in the EUR between waterflooding and polymer flooding cases at each well spacing. The EUR increase is plotted against the well spacing in Fig. 3.19. In general, increasing the well spacing degrades the incremental performance of the polymer flood over the waterflood. Larger well spacing leads to a lower inter-well pressure gradient and thus lower injectivity; polymer flooding is more sensitive to this injectivity decrease than waterflooding, so the differential performance of the polymer flood reduces. However, there is a limitation to this; at very tight well spacing, the waterflood performance improves more than the polymer flood performance, again causing the incremental performance of polymer flooding over waterflooding to decline. For reasonable well spacing optimized to consider well costs in this reservoir, we would generally expect tighter well spacing to yield improved polymer flood performance and greater incremental benefit.

The incremental NPV for polymer flooding over waterflooding is plotted against well spacing in Fig. 3.20. The trend is very similar to the incremental EUR. For moderate to large well spacing (smaller pressure gradients), increasing the well spacing reduces the incremental NPV for polymer flooding because the polymer flood is more affected by the lower inter-well pressure gradient causing injectivity challenges. However, for very tight well spacing (larger pressure gradients), the polymer flood incremental NPV again decreases since the waterflood performance begins to “catch-up” to the polymer flood. Overall, for reasonable well spacing, we would generally expect tighter spacing to yield improved economic performance for the polymer flood.

3.5 Discussion

3.5.1 Economic Modeling Tool
In deciding whether to implement a polymer flood or in evaluating the success of an existing project, it is important to consider the incremental performance of the polymer flood over waterflooding alone (Choudhuri et al. 2015; Sieberer et al. 2017; Thompson et al. 2018). The incremental economic analysis approach allows for a number of simplifications to be made by
canceling out cash flows that are similar between a waterflood and a polymer flood. This incurs a number of assumptions.

First, the incremental cost of water injection is assumed to be negligible. This is valid for a number of reasons. The water injection cost will be small relative to the cost of acquiring polymer. Furthermore, since water is injected in both the polymer and waterflood cases, a significant portion of the water injection will cancel out in the incremental calculation. This is a conservative assumption: the waterflood case will lead to a larger volume of water injected than the polymer case, meaning that this operating expense would actually show up as a benefit in the incremental economic analysis. Indeed, field experience in China indicates that the reduction in water injection can actually make polymer flooding cheaper than waterflooding (Gao 2011).

A second assumption is that the cost of the produced water treatment and disposal is also negligible. This assumption was made based on laboratory analysis, which revealed that the emulsion breakers currently used to separate the water and heavy oil would be sufficient even in the presence of polymer (Chang et al. 2020). Practically, the exact emulsion breaker cost allocation is currently unavailable. However, the question of the cost of water production may manifest itself in practice as a field-wide back-out opportunity cost, which is beyond the scope of this project. The additional comment should be made that a larger water volume is produced under the waterflood strategy relative to the polymer flood, so on a per-volume basis, this assumption is conservative, though the additional expense of polymer solution treatment may invalidate this statement. Again, field experience in China has indicated that reduced produced water volumes to treat can make polymer flooding cheaper than waterflooding (Gao 2011). Our decision in neglecting water injection and production is consistent with the incremental economic analysis pursued by Hidayat and ALMolhem (2019). Finally, it is clear from the robust results that our evaluation of the project as economically successful would not change even if additional costs are imposed.

Another assumption worth mentioning is that the gas treatment is assumed to be negligible. The low gas-oil ratio of the heavy oil makes this assumption very reasonable, especially since the incremental calculation would further reduce the amount of gas carried into the economic analysis.

In our pilot project’s patterns, the decision to implement polymer flooding did not require any additional well drilling or completion. As such, in our incremental economic analysis, well costs are not considered. Full-field scale polymer implementation may warrant additional wells
drilled, requiring well costs for a field scale design and optimization (Mogollón et al. 2016; Seright 2017; Sieberer et al. 2017). Again, this is beyond the scope of this pilot, where we are evaluating the decision to switch existing patterns from waterflooding to polymer flooding.

It is worth acknowledging the assumptions inherent in the price parameters supplied. The constant oil price assumption is not realistic – we know that oil price will vary in time. However, since we do not have the capability of predicting this with any certainty, a reasonable, conservative, constant value is used. This allows the economic modeling tool to be useful in indicating the potential for a project to succeed as well as for valuing that project compared to others in a portfolio. Our base oil price of $40 per barrel compares conservatively with other values used for similar work in literature, such as the $55 per barrel used by Ibiam et al. (2021). We further compensate for this simplification by testing the sensitivity to a range of oil prices. A similar discussion applies to the cost of polymer. Ibiam et al. (2021) supplied a polymer price of about $2 pound, while Delamaide (2016) assumed about $1.14 per pound. Our base cost of $1.50 per pound is intermediate, coming from Seright (2017).

Finally, the decision to neglect taxes and royalties in the economic analysis was made because this information is unavailable to us and is unnecessary for our purposes. The tax implications of the polymer pilot can only be adequately evaluated at the full-field level or beyond. By neglecting taxes and royalties, our analysis indicates the total benefit of the polymer flood campaign. It does not indicate how that benefit is distributed between the state, the operators, and other involved parties. The goal of this work is to indicate whether the polymer pilot is economically successful and to provide insight into improved polymer flood design. As such, our approach in neglecting taxes and royalties is fit-for-purpose and is consistent with other published works (Sieberer et al. 2017; Hidayat and ALMolhem 2019).

### 3.5.2 Economic Analysis

Our evaluation indicates that this polymer flood field pilot is an economic success. As seen in Table 3.5, at a conservative oil price of $40 per barrel, for all simulation cases tested we predict a positive and robust NPV, indicating that the decision to implement polymer flooding at the end of August 2018 was a good one. Furthermore, as demonstrated in Fig. 3.5, the project remains viable even at lower oil prices of $20 per barrel, indicating that our assessment remains valid even given the assumptions that limit our economic analysis. Additional incremental costs we neglected, such
as produced water treatment, can be roughly approximated in the model with a lower oil price (Seright 2017). Our conservative base oil price thus may indirectly account for these assumptions, and the success of the project even at lower oil prices further supports our assessment’s validity. It should be emphasized that for more optimistic oil prices, such as for the $80 per barrel price listed at the time of this writing, the project benefit grows substantially, making the polymer flood even more attractive.

The calculated polymer utilization further demonstrates the attractiveness of this polymer flood pilot independent of economic assumptions. As seen in Fig. 3.4, our best-calibrated forecasts (Full Model, $P_{bud}$) indicate a minimum polymer utilization of less than 1.5 lb polymer/bbl oil, achieved near 2022. Even by 2050, the cumulative polymer utilization remains under 4 lb/bbl. These values compare very favorably with other polymer utilization factors reported in the literature. As examples, polymer flooding in the Daqing oil field has reported commercial polymer utilization values between 3.3 and 7.4 lb/bbl, a polymer flood pilot in the Gudao ZYQ block of the Shengli oil field reported a polymer utilization of 2.5 lb/bbl, commercial-scale polymer flooding in the Shengli oil field produced an average polymer utilization of 7.4 lb/bbl, and polymer flooding in the Xinjiang oil field led to a polymer utilization of about 3.6 lb/bbl (Guo et al. 2021). Thus, we see that this ANS polymer flood pilot is highly efficient compared to other commercial polymer floods, corroborating its economic attractiveness.

One of the key takeaways from our previous simulation study was that a simulation model calibrated for waterflooding may not replicate the full benefit of polymer flooding or other enhanced oil recovery techniques (Keith et al. 2022). Here we have demonstrated the consequences of this on project economic evaluation. Model A was calibrated to the waterflood period only, whereas the Full Model was calibrated to all project data. When forecasts produced by these models are subjected to an economic analysis, we see that Model A underpredicts the project value by about 25%, estimating a $31.9 million project compared to the Full Model estimate of $42.9 million. In this case, the discrepancy would not alter our overall evaluation of the polymer flood pilot as being an economic success. However, if future polymer flooding projects in other patterns are scoped on the basis of waterflood-calibrated simulation models, the potential for the waterflood-based model to not capture the full benefit of polymer injection could erroneously indicate unattractive economics for polymer flooding.
On the other hand, Model B overpredicted the project value by about 45%, predicting a $61.4 million project. Model B failed to account for a future loss in injection conformance captured by the Full Model. Fracture overextension has been proposed as a reasonable explanation for this discrepancy (Keith et al. 2022). Model B likely captured the improvement in injectivity expected from fracture development, but it did not anticipate the fractures extending too far and degrading the sweep efficiency (Seright 2017). This is another important cautionary tale demonstrating how dynamic reservoir events can invalidate previous simulation models. Simulation forecasts should be taken as living forecasts, especially for dynamic heavy oil–polymer systems in unconsolidated sands.

3.5.3 Design Sensitivity Analysis

3.5.3.1 Injected Polymer Concentration and Throughput Rate

The injected polymer concentration and throughput rate from September 2021 onwards were varied individually in our tests. In general, increasing either parameter increased the oil production and thus increased the project value (Fig. 3.6, Fig. 3.8, Fig. 3.9, Fig. 3.11). This is consistent with the concept that increasing the amount of polymer injected into the reservoir should generally increase oil recovery (Choudhuri et al. 2015; Anand et al. 2018). However, injectivity imposes a limit in increasing either parameter, forcing a balance between improving sweep efficiency by increasing polymer concentration versus accelerating recovery through higher rates (Sieberer et al. 2017; Thompson et al. 2018; Sabirov et al. 2020). In our tests, too high a polymer concentration led to a decline in value due to injectivity losses (Fig. 3.8). On the other hand, the throughput rate was limited in the simulation model by the BHP constraint, resulting in a plateau in value (Fig. 3.11).

The development of fractures in the reservoir makes this question even more involved. The fractures provide improved injectivity that should accommodate higher polymer concentrations or flow rates, even though the fractures became overextended and hampered the sweep efficiency (Seright 2017). Because the reservoir is unconsolidated, these fractures may actually appear as a high-permeability band or “pseudofracture” (Khodaverdian et al. 2010); increasing the injected polymer viscosity may thus be preferable to improve the sweep efficiency in the face of these increased heterogeneities. Furthermore, the physical ability of the operator to increase the throughput rate depends on a number of additional limiting factors that may be absent or poorly
represented by the simulation model (Delaplace et al. 2013). Our simulation approach is also limited in that the high-transmissibility strips used to replicate a pseudofracture feature remain static with respect to rate or pressure; thus, additional dynamic effects could dissuade one from increasing the throughput rate for fear of further damaging the reservoir. Thus, based on this work, our recommendation for the future operation of these patterns is to consider increasing the injected polymer concentration. Up to injectivity constraints, increasing the polymer solution viscosity within the limits of injectivity should provide greater financial benefits (Seright 2017). In practice, a profile treatment such as a colloidal dispersion gel may be performed instead to restore the degraded sweep efficiency resulting from fracture overextension (Seright 2017). Based on laboratory analysis, if these “pseudofractures” develop a high permeability (> 50 darcies), a 260-μm microgel particle treatment could be effective for penetrating and shutting off the channel, diverting polymer injection back into the matrix (Zhao et al. 2021).

3.5.3.2 Polymer Injection Duration

Many polymer flood studies have provided consideration to the duration of polymer injection (Choudhuri et al. 2015; Sieberer et al. 2017; Hidayat and ALMolhem 2019; Sabirov et al. 2020; Xu and Lu 2020). Often, these analyses are based on the concept that prolonged polymer injection will not provide additional benefit compared to injecting chase water to push a mature polymer bank and oil bank through the reservoir (Green and Willhite 2018; Hidayat and ALMolhem 2019). In practice, the chase water will finger through the polymer bank, causing the water cut to increase and the oil production to decline (Fabbri et al. 2015; Seright 2017; Anand et al. 2018). Our simulation approach attempts to capture this effect by re-introducing high transmissibility strips to a waterflood following polymer injection. The results in Fig. 3.12 demonstrate that the oil production flattens immediately and dramatically when the polymer flood is switched to a waterflood, consistent with the water fingering through the polymer bank. Given this and practical water cut constraints for producing wells, it is not recommended that this polymer flood pilot be switched back to waterflooding. When the polymer flood is no longer beneficial, we believe the correct course of action is to abandon the pattern or consider other methods to improve the oil recovery rather than switching back to a waterflood.

It is important to understand when a polymer flood is no longer providing benefit. However, this depends strongly on the economic context at the time (Seright 2017). Our point-
forward polymer utilization plot (Fig. 3.13) indicates the efficiency of an additional increment of polymer injection, independent of economic parameters. Thus, plots like this can inform the future decision of when to postpone or abort polymer injection.

The caveat should be provided that our analysis focuses only on a single set of patterns. Other studies have considered the full-field perspective, comparing individual pattern polymer efficiencies to determine which patterns should be prioritized for polymer injection (Clemens et al. 2011; Choudhuri et al. 2015). Given limited polymer supply, polymer injection should be prioritized to the patterns that will benefit the most; however, an alternative course of action may be to increase the amount of polymer supplied to the field if patterns continue to benefit based on prevailing economic conditions.

3.5.3.3 Polymer Injection Start Time

A significant point of discussion in the literature has revolved around whether it is preferable for waterflooding to precede polymer flooding or if production should start under polymer flooding only. Some laboratory floods have suggested that an initial waterflood could stabilize the successive polymer flood (Fabbri et al. 2014), while other laboratory work suggests that the starting conditions for a polymer flood will not influence the ultimate recovery (Skauge et al. 2014). Field practice points out a number of other benefits to waterflooding first, including providing a baseline for performance comparison, allowing an earlier project startup without delay in establishing polymer facilities, filling the reservoir with a cheaper fluid, and avoiding delays in pressure support from injectivity challenges (Delaplace et al. 2013; Delamaide 2016). However, the majority of field practice indicates that polymer flooding should be commenced as early as possible in pattern development, when the mobile oil saturation is higher and before irreversible water channeling creates paths of higher water relative permeability that could degrade polymer flooding performance (Gao 2011; Delamaide 2016; Sieberer et al. 2017; Thompson et al. 2018; Ibiam et al. 2021).

As Fig. 3.15 shows, our work is consistent with the idea that the starting conditions for polymer flooding do not influence the ultimate recovery from patterns if no additional constraints (such as producing water cut) are imposed. However, there is a significant preference for earlier polymer injection from a net present value perspective. The higher mobile oil saturation in earlier times allows the polymer flood to achieve higher oil rates for a more sustained duration (Fig. 3.14);
higher rates achieved earlier in time will increase the NPV of a project significantly. Thus, the overall recommendation from this test is to commence polymer flooding as soon as possible.

It is also worth acknowledging that our test indicates that the optimal production scenario should involve about half a year of waterflooding followed by polymer flooding rather than starting with polymer outright. This is based on the premise that the injecting wells will be able to provide greater volumes under waterflooding than polymer flooding, so the producing wells will be able to draw greater volumes while maintaining a voidage replacement of unity. In practice, many real-world factors unaccounted for in our simulation influence the first months of production life to nullify this conclusion. For example, ANS viscous oil producing wells are normally opened gradually to avoid forming matrix bypass events (Paskvan et al. 2016). In addition, producing and injecting wells are not all drilled at the same time and may come online with a few weeks or months of stagger. Producing wells may be able to achieve high oil rates early on from primary production. For these reasons, it is unlikely that the actual production behavior between waterflooding and polymer flooding will be as different during the first months of pattern life as our simulation supposes. As such, the higher oil rate achieved in our simulation for waterflooding in the first months is likely an artifact of oversimplification and idealization. Therefore, our practical recommendation is to start polymer injection as soon as possible, though if polymer facility set-up is delayed, waterflooding may be value-generating in the meantime.

3.5.3.4 Well Spacing

Many studies have identified the importance of well spacing, patterning, and location on waterflooding and polymer flooding performance (Paskvan et al. 2016; Sieberer et al. 2017; Garg et al. 2018; Hidayat and ALMolhem 2019; Ibiam et al. 2021). A number of these works pursue well spacing as an optimization parameter (Sieberer et al. 2017; Hidayat and ALMolhem 2019; Ibiam et al. 2021). Our work demonstrates the sensitivity of recovery factor to well spacing for both polymer flooding and waterflooding, showing that increasing the well spacing decreases the oil recovery (Fig. 3.17). However, we are unable to execute a true well spacing optimization with our incremental economic modeling tool.

Specifically, for both polymer flooding and waterflooding, the cost of drilling and completing the wells is assumed to be the same, so these costs are not considered in the incremental analysis. However, the question of optimizing well spacing is strongly influenced by the well
costs, since a tighter well spacing would often necessitate additional drilling in order to produce the same total oil volume (Seright 2017). As such, our incremental economic analysis does not inform us of the economically optimal well spacing to drill for future polymer flood projects.

However, our analysis does tell us what well spacing would yield greater incremental economic performance under polymer flooding relative to waterflooding. In other words, if we have patterns in an identical reservoir with different well spacing, this test will tell us which patterns we would prioritize for polymer injection. As seen in Fig. 3.19 and Fig. 3.20, for the larger well spacing typical of ANS viscous oil production (Garg et al. 2018), we would prioritize tighter spaced patterns for polymer injection due to the sensitivity of polymer to injectivity issues (Hidayat and ALMolhem 2019).

3.6 Conclusions
An economic modeling tool was custom-built to analyze the performance of polymer flooding incremental to waterflooding. Integrating this tool with a range of calibrated reservoir simulation models yielded the following insights:

1. 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.
2. A simulation model calibrated for waterflooding may not accurately capture the full benefit of an enhanced oil recovery strategy such as polymer flooding, with notable consequences in the resulting economic evaluation.
3. However, failing to account for the potential of fracture development and overextension from higher injection pressures during polymer flooding may also significantly impact economic evaluation.
4. Within limits of injectivity, increasing the injected polymer concentration can increase the oil recovery and improve project economics.
5. Within limits of injectivity and other operational constraints, increasing the throughput rate can improve oil recovery and project economics.
6. There is little benefit in switching from a polymer flood back to a waterflood for the reservoir considered. Determining when polymer flooding is no longer viable depends
on the prevailing economic conditions of the time, but this decision can be informed by efficiency measures such as the proposed point-forward polymer utilization.

7. For patterns where polymer flooding is deemed beneficial, it is economically preferable to implement the polymer flood as early as reasonably possible.

8. Given line-drive patterns in the same reservoir with different reasonable horizontal well spacing, polymer flooding should be prioritized to the tighter spaced patterns.

3.7 Acknowledgements
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3.8 Nomenclature
\[
\begin{align*}
ANS &= \text{Alaska North Slope} \\
BHP &= \text{bottomhole pressure, psi} \\
BTCF &= \text{before tax cash flow, $} \\
CAPEX &= \text{capital expenditure, $}
\end{align*}
\]
\[ C_f = \text{cost of polymer facility acquisition and installation, } \$
\[ C_m = \text{cost of additional maintenance and surveillance, } \$
\[ C_o = \text{oil price, } \$/\text{bbl}
\[ C_p = \text{cost of polymer acquisition and transport, } \$/\text{lb}
\[ EUR = \text{expected ultimate recovery, } \%
\[ i = \text{discount rate, } \% \text{ per annum}
\[ M_p = \text{cumulative polymer mass injected, lb}
\[ M_{p,n} = \text{monthly polymer mass injected, lb}
\[ n = \text{number of the project month}
\[ N = \text{maximum number of project months}
\[ NPV = \text{net present value, } \$
\[ OPEX = \text{operating expenditure, } \$
\[ PFPU = \text{point-forward polymer utilization, lb/bbl}
\[ PI Ratio = \text{discounted profit to investment ratio}
\[ PUF = \text{polymer utilization factor, lb/bbl}
\[ t = \text{time, months}
\[ V_{o,p} = \text{cumulative oil production under polymer flooding, bbl}
\[ V_{o,p,n} = \text{monthly oil production under polymer flooding, bbl}
\[ V_{o,w} = \text{cumulative oil production under waterflooding, bbl}
\[ V_{o,w,n} = \text{monthly oil production under waterflooding, bbl}

3.9 References


Delamaide, E. 2016. Comparison of Primary, Secondary, and Tertiary Polymer Flood in Heavy Oil – Field Results. Paper presented at SPE Trinidad and Tobago Section Energy Resources Conference, Port of Spain, Trinidad and Tobago, 13-15 June. SPE-180852-MS. https://doi.org/10.2118/180852-MS


3.10 Figures

Figure 3.1 ANS viscous and heavy oil resource. The blue shading represents viscous oil, with the darker blue indicating areas under current development. The purple outline represents heavy oil, not yet developed (Paskvan et al. 2016).

Figure 3.2 ANS polymer flood field pilot reservoir boundaries, with injector-producer well patterns (Dandekar et al. 2019).
Figure 3.3 Predicted oil recovery for each forecasted simulation case. The best matched model forecast for each case is indicated with a solid line, the most optimistic forecast for each case is indicated with a dashed line, and the most pessimistic forecast for each case is indicated with a dotted line.
Figure 3.4 Polymer utilization plot for each simulation case. The best matched model forecast for each case is indicated with a solid line, the most optimistic forecast for each case is indicated with a dashed line, and the most pessimistic forecast for each case is indicated with a dotted line. The historic production period (Sept. 2018 – Sept. 2021) is included.

Figure 3.5 Sensitivity of base case (best matched Full Model) NPV assessment to economic parameters. Sensitivity is measured as the percent deviation in the NPV from the base case. The optimistic and conservative values of the economic parameters are given in Table 3.4.
Figure 3.6 Forecasted oil recovery factor at various injected polymer concentrations (from Sept. 2021 onwards).

Figure 3.7 Polymer utilization for various injected polymer concentrations.
Figure 3.8 NPV (incremental to waterflood) versus injected polymer concentration (from Sept. 2021 onwards).

Figure 3.9 Forecasted oil recovery factor at various throughput rates (from Sept. 2021 onwards). Note that the 4000 BPD case is nearly identical to the 3500 BPD case.
Figure 3.10 Polymer utilization for various throughput rates.

Figure 3.11 NPV (incremental to waterflood) versus target total throughput rate (through Sept. 2021).
Figure 3.12 Oil recovery factor forecast for various timing for switch from polymer flooding back to waterflooding.

Figure 3.13 Minimum point-forward polymer utilization versus year for switching from polymer injection back to water injection.
Figure 3.14 Oil production rate at various polymer flood initiation times.

Figure 3.15 Oil recovery factor at various polymer flood initiation times.
Figure 3.16 NPV (incremental to waterflood) versus start time for polymer injection. Note that the June 2016 case represents polymer flooding only with no preceding waterflood.

Figure 3.17 Oil recovery factor for polymer flooding (solid line) and waterflooding (dashed line) for various well spacing.
Figure 3.18 Polymer utilization plot for various well spacing.

Figure 3.19 Increase in expected ultimate recovery for polymer flooding over waterflooding versus well spacing.
Figure 3.20 NPV (incremental to waterflood) versus well spacing.
### 3.11 Tables

**Table 3.1 Reservoir properties for ANS J-pad polymer flood pilot**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>API °</td>
<td>15.4</td>
</tr>
<tr>
<td>Oil viscosity (cp)</td>
<td>332</td>
</tr>
<tr>
<td>Horizontal permeability (mD)</td>
<td>500 – 5,000</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>32</td>
</tr>
<tr>
<td>Reservoir depth (ft)</td>
<td>3,600</td>
</tr>
<tr>
<td>Reservoir thickness (ft)</td>
<td>15</td>
</tr>
<tr>
<td>Initial reservoir pressure (psi)</td>
<td>1,600</td>
</tr>
<tr>
<td>Bubble point pressure (psi)</td>
<td>1,303</td>
</tr>
<tr>
<td>Reservoir temperature (°F)</td>
<td>70</td>
</tr>
<tr>
<td>Rock compressibility (1/psi)</td>
<td>30E-6</td>
</tr>
</tbody>
</table>

**Table 3.2 Constraints for polymer flood forecasting (Keith et al. 2022)**

<table>
<thead>
<tr>
<th>Well</th>
<th>Liquid Rate (STB/D)</th>
<th>BHP (psi)</th>
<th>Poly. Conc. (ppm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>J-23A</td>
<td>1,500</td>
<td>2,600</td>
<td>1,200</td>
</tr>
<tr>
<td>J-24A</td>
<td>500</td>
<td>2,600</td>
<td>1,200</td>
</tr>
<tr>
<td>J-27</td>
<td>1,000</td>
<td>800</td>
<td>-</td>
</tr>
<tr>
<td>J-28</td>
<td>1,000</td>
<td>650</td>
<td>-</td>
</tr>
</tbody>
</table>

**Table 3.3 Constraints for waterflood forecasting (Keith et al. 2022)**

<table>
<thead>
<tr>
<th>Well</th>
<th>Liquid Rate (STB/D)</th>
<th>BHP (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>J-23A</td>
<td>2,100</td>
<td>2,100</td>
</tr>
<tr>
<td>J-24A</td>
<td>1,600</td>
<td>2,200</td>
</tr>
<tr>
<td>J-27</td>
<td>2,200</td>
<td>900</td>
</tr>
<tr>
<td>J-28</td>
<td>1,500</td>
<td>700</td>
</tr>
</tbody>
</table>

**Table 3.4 Input economic parameters**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Base Value</th>
<th>Conservative Value</th>
<th>Optimistic Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Price</td>
<td>$40 per barrel</td>
<td>$20 per barrel</td>
<td>$80 per barrel</td>
</tr>
<tr>
<td>Polymer Acquisition &amp; Transport</td>
<td>$1.50 per pound</td>
<td>$2 per pound</td>
<td>$1 per pound</td>
</tr>
<tr>
<td>Polymer Facility Acquisition &amp; Installation</td>
<td>$3 Million</td>
<td>$4 Million</td>
<td>$2 Million</td>
</tr>
<tr>
<td>Add’l Maintenance &amp; Surveillance</td>
<td>$100,000 per annum</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Discount Rate</td>
<td>10% per annum</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

96
<table>
<thead>
<tr>
<th>Case</th>
<th>FULL MODEL</th>
<th>MODEL B</th>
<th>MODEL A</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>P_best</td>
<td>P_high</td>
<td>P_low</td>
</tr>
<tr>
<td>NPV ($ Million)</td>
<td>42.9</td>
<td>45.5</td>
<td>41.3</td>
</tr>
<tr>
<td>Discounted PI Ratio</td>
<td>5.05</td>
<td>5.36</td>
<td>4.87</td>
</tr>
<tr>
<td>Development Cost ($/bbl)</td>
<td>8.35</td>
<td>8.02</td>
<td>8.80</td>
</tr>
<tr>
<td>Incremental Recovery Factor (%)</td>
<td>15.1</td>
<td>15.7</td>
<td>14.3</td>
</tr>
</tbody>
</table>
Chapter 4  Conclusions and Recommendations

4.1 Conclusions

This work provides a case study demonstrating a workflow to evaluate a polymer flood field pilot. This evaluation indicates that the first ever polymer flood field pilot to enhance the recovery of heavy oils on the Alaska North Slope is a technical and economic success. Potential mechanisms behind this success are illuminated.

The following conclusions were drawn from this work:

1. To correctly simulate waterflooding in a heavy oil reservoir, horizontal transmissibility contrasts were introduced to the simulation model to recreate the viscous fingering behavior motivating the observed early water breakthrough.

2. To capture the full benefit of the polymer flood in the simulator, the dampening of viscous fingering behavior was represented through the reduction in the horizontal transmissibility contrast.

3. To simulate the effects of fracture overextension during polymer flooding, transmissibility contrasts were reintroduced. Fracture overextension decreases the oil recovery expectation.

4. Machine-assisted history matching procedures allowed many parameters to be varied independently, producing a more reasonable calibrated model than manual procedures. This is gauged by the reduced frequency of transmissibility changes in time and the simultaneous matching of producing water cut, produced polymer concentration, and BHP.

5. The polymer flood field pilot is deemed a technical success because all calibrated simulation models predict significantly higher oil recovery from polymer flooding than waterflooding alone.

6. The polymer flood field pilot is deemed an economic success because all calibrated simulation models remain robustly profitable in a range of conservative economic scenarios.

7. A simulation model calibrated for waterflooding may not accurately capture the full technical and economic benefit of an EOR strategy such as polymer flooding. More generally, the predictive capacity of a simulation model is limited by the flow behavior captured in the production history. Thus, a previously calibrated simulation model and its
economic indications may no longer be valid for predictions if events occur to change this flow behavior. In particular, caution is recommended when using a waterflood-calibrated model to scope potential polymer flooding candidates.

8. Within limits of injectivity, increasing the injected polymer concentration can increase the oil recovery and improve project economics.

9. Within limits of injectivity and other operational constraints, increasing the throughput rate can improve oil recovery and project economics.

10. For the reservoir considered, there is little benefit in switching from a polymer flood back to a waterflood. Determining when polymer flooding is no longer viable depends on the prevailing economic conditions of the time, but this decision can be informed by efficiency measures such as the proposed point-forward polymer utilization.

11. For patterns where polymer flooding is deemed beneficial, it is economically preferable to implement the polymer flood as early as reasonably possible.

12. Given line-drive patterns in the same reservoir with different reasonable horizontal well spacing, polymer flooding should be prioritized to the tighter spaced patterns.

4.2 Recommendations

From this work and these conclusions, the following recommendations for future work are provided:

1. The current polymer flood field pilot is economically attractive and should continue to be operated.

2. Polymer flooding may be an attractive option to unlock additional heavy oil resources on the Alaska North Slope. For patterns where severe viscous fingering during waterflooding is observed or anticipated, polymer flooding should be considered as a potential solution.

3. Polymer flooding for heavy oil recovery on the Alaska North Slope should be expanded to other patterns to verify the results of this pilot.

4. The potential for produced polymer recycling to improve project economics should be investigated through modification of the simulation and economic models developed in this work.

5. To verify the efficacy of our history matching approach, other heavy oil floods under waterflooding and polymer flooding should be simulated using transmissibility contrast as
a time-adjusted parameter. If successful, relations between the required transmissibility contrast and known rock and fluid properties should be developed. This would allow *a priori* assumptions of the transmissibility contrast change under changing injected fluid viscosity or for scoping future patterns.

6. Our work upscaled the viscous fingering effect into a pseudoized geologic model. Other researchers have chosen to embed the viscous fingering effect into pseudo-relative permeability curves. This latter approach should be applied to this field pilot to compare the results of the two methods.

7. Other enhanced oil recovery processes, such as CO₂ flooding or other solvent flooding; polymer-alternating-solvent flooding; surfactant, surfactant-polymer, or alkali-surfactant-polymer flooding; microbial flooding; or nanoparticle flooding should be scoped for potential application on the Alaska North Slope via appropriate modification of the simulation and economic model developed in this work in conjunction with core flooding and other laboratory analyses.

4.3 References


