UGNU PILOT AREA – SIMULATION MODEL

AND SENSITIVITY ANALYSIS

By

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Abstract

Collaborating with Hilcorp Alaska, LLC, the Ugnu pilot area is the subject of this project. Hilcorp Alaska is conducting field pilot test at Milne Point Field to prove commerciality with Ugnu heavy oil as well as an on-going Milne viscous oil polymer flood field pilot test in the Schrader Bluff sands. The Ugnu sand heavy oil represents much of the heavy oil on Alaska's North Slope and has potential for future development. Typical heavy oil has a viscosity of 1,000 – 10,000 centipoise, approximately akin to viscosities of honey and molasses, respectively. North Slope heavy oil is located around 3,000-foot depths and typically overlays existing fields. The project involves a reservoir simulation model and sensitivity analysis to support developmental drilling plans from a Milne Point Unit pad. Necessary geologic and reservoir properties were provided for usage in this project by Hilcorp. Production data was provided for history matching. Field geologic background was also supplied to aid in the understanding of the reservoir. The reservoir simulation model was built using Computer Modelling Group software, namely Builder and IMEX. The first model iteration contained one producer in an 8,500-foot lateral pattern. Further iterations included additional producers and injectors for waterflood and polymer flood studies. Conclusions and recommendations were drawn upon analyzing the reservoir simulation results centering around favorable production strategies, polymer flood performance, comparison to the on-going Milne viscous oil polymer flood pilot, and future polymer flood studies.

Completed objectives of this project included:

1. Developing a numerical reservoir simulation model for the Ugnu MB sand in the pilot area;
2. Evaluating the productivity of horizontal wells in the Ugnu MB sand;
3. Predicting ultimate oil recovery with waterflood and polymer flood;
4. Predicting polymer utilization, polymer injected per incremental oil barrels over waterflood.

Acknowledgments

I would like to express sincere gratitude to several individuals and organizations for supporting me throughout my Master's study. First and foremost, I would like to express my sincere thanks to Dr. Samson Ning, for his patience, enthusiasm insightful comments, practical advice, invaluable suggestions, helpful information, and unceasing ideas which have helped me tremendously at all times throughout this project and writing this report. His immense knowledge, profound experience, and professional expertise in reservoir engineering have enabled me to complete this project successfully I am thankful to him for his precious time in guiding me and answering my questions. Without his guidance and relentless help, this project would not have been possible.

My gratitude is extended to Hilcorp Alaska for making this project possible. Partnering with UAF to make real-world projects possible for students is a blessing and greatly enhances student learning and career possibilities. I would like to thank contributing members of Hilcorp for this project, including geologist Seth Nolan for aiding in this project including providing geologic models, and any other Hilcorp staff involved.

I would also like to thank the UAF Petroleum Engineering Department for my acceptance into the Master's program and their support throughout my journey through the program, including partnering with Hilcorp for this project. The faculty is fantastic and my success in the program would not have happened without their efforts. My thanks are extended to members of my graduate committee, Dr. Abhijit Dandekar and Dr. Yin Zhang.

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CHAPTER 1 INTRODUCTION

1.1 Overview

The vast resources of heavy oils above the famous fields including Prudhoe Bay is not well known. These heavy oil reservoirs are comparable in size to the light oil fields. The reservoirs containing lighter heavy oils (commonly referred to as viscous oils) in the Schrader Bluff or West Sak formations are in the process of being developed across the North Slope. However, the heavier oils in the shallower Ugnu formation has not been commercially developed. Constraints include technology factors and economics. Early appraisal results have been obtained via cold heavy oil production with sand (CHOPS) flowback and multi-zone drill-stem testing to obtain quality reservoir fluid samples. Cold production of heavy oil is possible and warrants further pilots. Massive sand production might not be necessary and horizontal wells may be a viable development alternative to CHOPS (Young et al. 2010).

The study area is within the Milne Point Unit (MPU) and is bordered closely by the Kuparuk River Unit and the Prudhoe Bay Unit. The area has significant heavy oil resources, refer to Figure 1. The geologic depositional environment is a distributary channel belt system. These tend towards a high net/gross ratio. The Ugnu formation interval is 350 feet gross and 250 feet net. Depth is approximately 3,500 feet to 4,000 feet. From core and thin section analysis, porosity values range from 24% to 40%. Gross permeability ranges from 5 to 13,000 mD. Oil is cold and heavy, with temperatures from 68 degrees to 75 degrees Fahrenheit. Oil quality ranges from 500 cp to 10,000 cp. The Ugnu consists of two main intervals, the L-Sands and the M-Sands, both with five intervals each. The MB sands are one of the two primary prospective sands in the M-Sands, with the other being MD sands. Per a Hilcorp developmental drilling plan later discussed, GR pay cutoff is 50 API, 24 ohm*m RESD (Deep Resistivity), and 31% porosity. Three S-37 cores have been analyzed by Omni/Weatherford, with the core reflective of the entire MB sand interval, yielding various permeability and porosity values. Ugnu's structure includes a regional monocline in the ENE to E dip. Ugnu oil type is heavy oil (like honey) and has potential for development. Light oils (like water) on the North Slope has been mostly developed, with examples being Prudhoe, Kuparuk, and Sag River reservoirs. Viscous oil (like syrup) has started development, such as West Sak / Schrader Bluff reservoirs (Pospisil, 2011). Figure 2 offers an overview of viscosity vs. depth for Alaska North Slope oil fields.

Hilcorp provided documentation in the form of a subsurface overview and a development drilling plan for the Milne Point Field Ugnu MB Sands from the respective pad. This contained information on drilling recommendations and objectives, development history, volumetrics, gravity/viscosity maps, and porosity-perm correlations. The program summary recommendation is to drill a horizontal well pattern in the Ugnu MB sand, with 2 producers and 2 injectors. One producer has already been drilled and is producing under primary depletion. This well is WELL-3, and its historical production data is used as the basis of history matching. WELL-3 is an 8,500-foot lateral well drilled from the respective MPU pad. A top structure map and geologic context map were provided by Hilcorp showing the proposed well pattern. WELL-3 pattern volumetrics was an area of 654 acres, net pay of 20 feet, porosity of 33%, water saturation of 25%, and oil formation volume factor of 1.04 reservoir barrels per stock tank barrel. This study will evaluate the productivity of the drilling development plan. The objectives of the program are to prove sustainable production from the Ugnu reservoir, develop a 24 MMBO OOIP Ugnu MB sand waterflood pattern, and to predict ultimate oil recovery with waterflood and polymer flood.

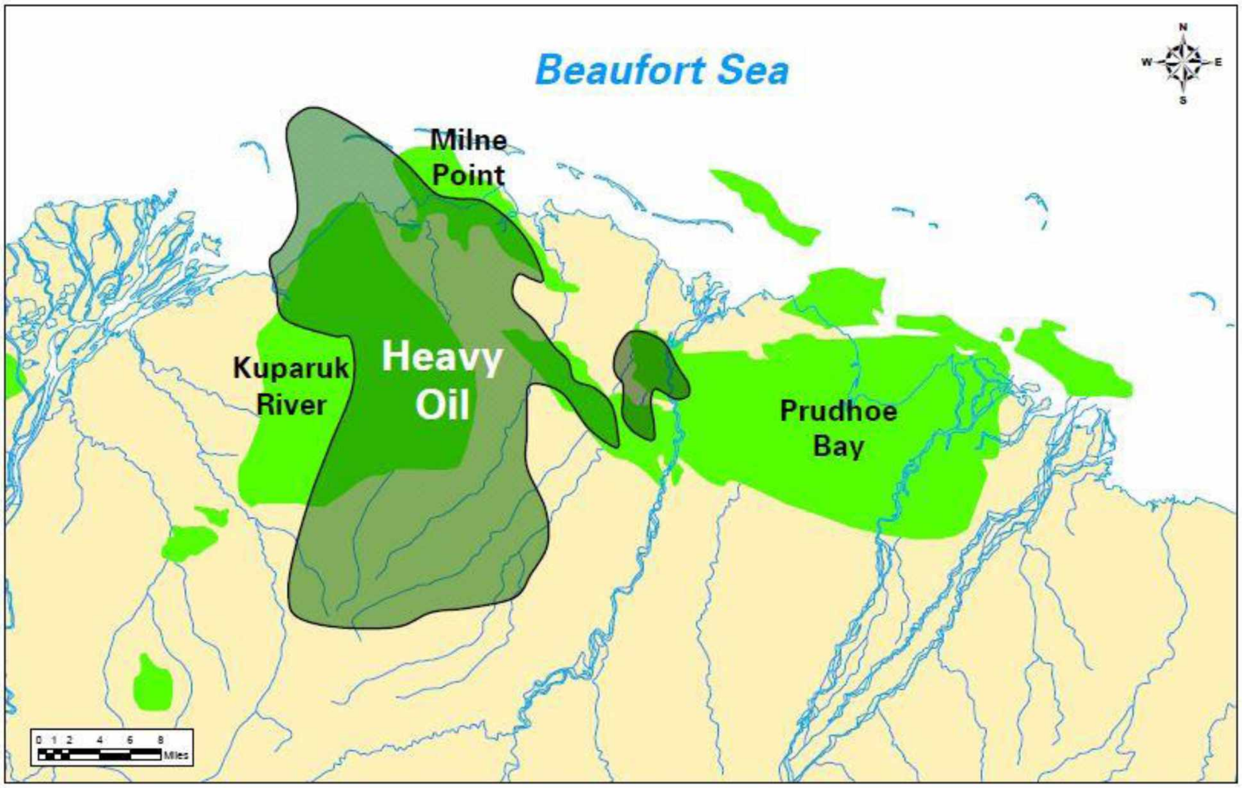

Figure 1: Alaska North Slope Heavy Oil (Pospisil, 2011)

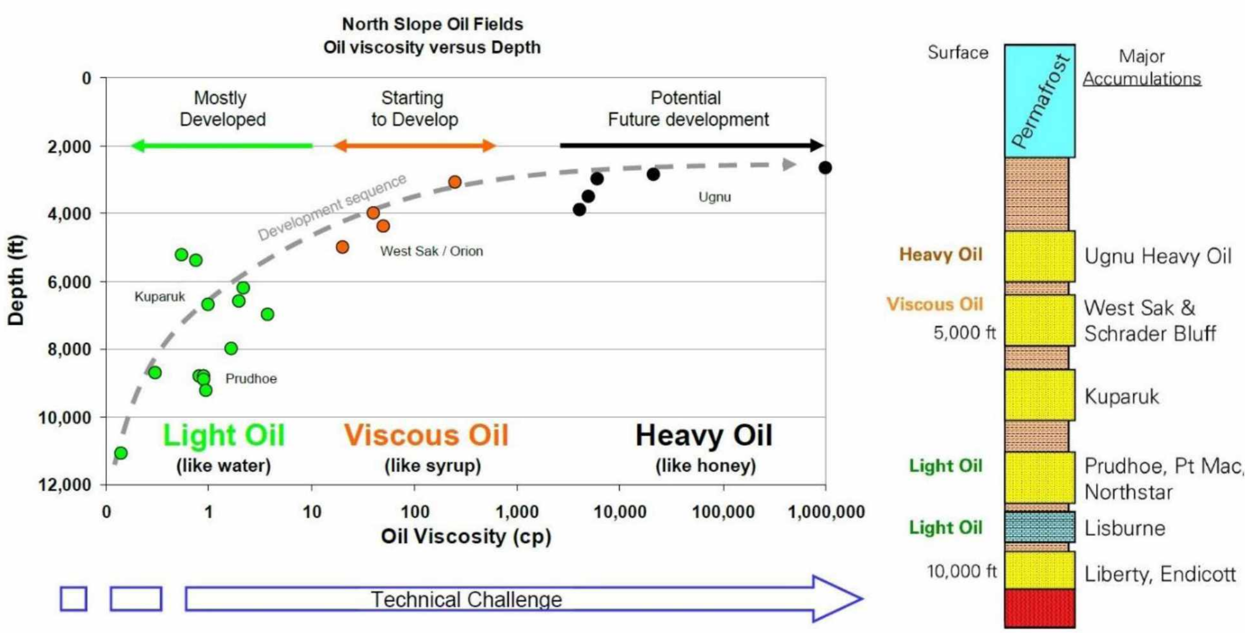

Figure 2: Alaska North Slope Oil Fields – Oil Viscosity vs. Depth (Pospisil, 2011)

1.2 Objectives

Objectives fall into two categories, report objectives, and study objectives.

Report objectives are preparing a report from the study that fulfill graduate school requirements for Master's Degree in Petroleum Engineering, conduct a literature review on relevant concepts such as polymer flooding, assist industry through academic participation, and building on / expanding the student's knowledge of industry and petroleum engineering topics at hand.

Study objectives are the following:

Collaborating with Hilcorp Alaska, LLC, the Ugnu pilot area will be the subject of this study. The project will involve a reservoir simulation model and sensitivity analysis to support developmental drilling plans from an MPU (Milne Point Unit) pad. This study will evaluate the productivity of the drilling development plan. The objectives of the program are to prove sustainable production from the Ugnu reservoir and develop a 24 MMBO OOIP Ugnu MB sand waterflood pattern. Detailed objectives of the program include:

1. Develop a numerical reservoir simulation model for the Ugnu MB sand in the Milne Point Unit pad pilot area;
2. Evaluate the productivity of horizontal wells in the Ugnu MB sand;
3. Predict ultimate oil recovery with waterflood;
4. Predict ultimate oil recovery with polymer flood;
5. Predict polymer utilization; polymer injected per barrel of incremental oil over waterflood.

CHAPTER 2 LITERATURE REVIEW

2.1 Ugnu Geology and Rock Properties

The sands of Ugnu and West Sak are part of the strata known as "Shallow Sands." Such strata comprise a portion of the marine and deltaic complex Late Cretaceous and Early Tertiary, which formed in the Kuparuk region (Hallam et al. 1992). The reservoir Lower Ugnu (M-sands) is the subject of recent evaluation and is approximated at 12-18 Bbbls. For deeper targets and several high-quality 3D seismic surveys, approximately 1,500 wells penetrate the Ugnu sands. (Young et al. 2010). The Stratigraphy of Ugnu is shown in Figure 3.

Regarding sedimentology, the Ugnu is a fluvial/deltaic series which is dominated by highly unconsolidated sand, with the sediment loosely arranged and not in layers. In the northern section of the Kuparuk River Unit, the 2 to 4 mile-wide east-west trending channel belt stretches for more than 9 miles. The sands have a high net/gross ratio inside the main channel belt, with areas of net pay over 75 ft varying from 0.74 to 0.92, with 0.8 average (Hallam et al. 1992).

The arrangement of Ugnu is characterized by a standard faulted northeasterly monoclinal dip. The Ugnu system gradually dips at about 2° from southwest to northeast. Early assessments of the interval set the depth of the thick pay interval between 2,200 and 3,200 feet. More recent data of Ugnu pool depth range from 4,500 feet in the east to 3,000 feet in the west (Young et al. 2010). There are common faults, and the structure of Ugnu is cut. 3D seismic results show predominant patterns as north-south and north-west-south. Through having effective up-dip and lateral seals, these faults help to compartmentalize the Ugnu reservoir.

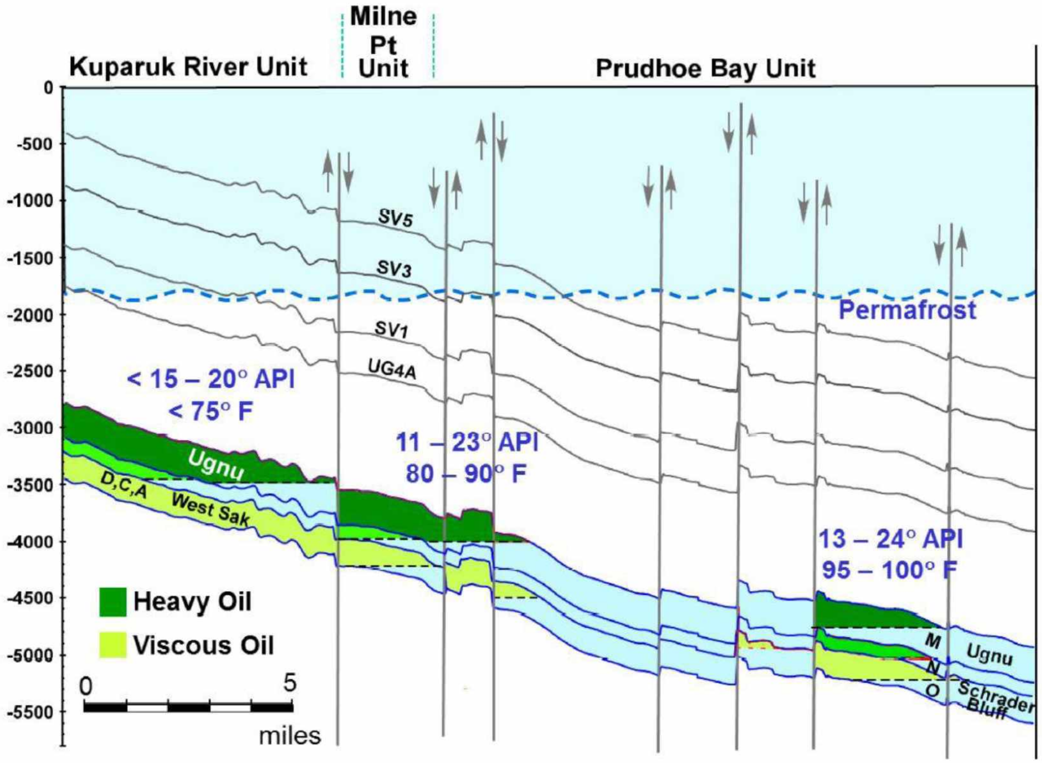

Figure 3: Ugnu Stratigraphy (Paskvan et al., 2016)

The log-derived average porosity for the main reservoir sand shows a general decrease from 37% in the west to 34% in the east, a porosity decrease corresponding to an increase in depth. The average oil saturation within the best portions of the reservoir varies from 66% to 72%. The data was from well-log analysis tunes with available core data (Hallam et al. 1992).

Permeability range is wide, with early estimates putting the target permeabilities above 700 mD and to several 1,000 mD, with low estimates down to several mD (Hallam et al. 1992).

Reservoir pressure is almost that of a normal hydrostatic pressure gradient of 0.433 psi/ft. Hallam et al. cite a reservoir pressure at a well in their study at 1,328 psi at 2,978 ft, equivalent to a pressure gradient of 0.446 psi/ft.

2.2 Ugnu Fluid Properties

Permafrost is a dense soil layer usually present in Arctic regions and stays frozen during the year. Permafrost plays a crucial role in the Ugnu production as it affects the temperature of the reservoir and thus the viscosity of the crude. Because of issues about melting the permafrost, thermal stimulation, and processing techniques such as steam injection are widely considered inefficient, creating several problems including stressing the well casing system. Many considerations include energy conservation and environmental damage. The thickness of permafrost within the region that includes the dense accumulation of Ugnu averages around 1,650 feet. The temperature at the base of the ice-bearing permafrost layer is around 31°F, with a temperature gradient of 1.1°F per 100 feet through the layer. The proximity to permafrost and resulting in lower temperatures harm the oil quality and results in heavier crude. Higher quality of Ugnu oil increases to the east, due to increased west to east burial depth. Figure 4 offers an example of how depth and proximity to permafrost influence the temperature of the oil and hence increase the viscosity. 15°C corresponds to 59°F, approximately reservoir conditions (Hallam et al. 1992). In general, reservoir temperature is estimated from 45°F to 75°F.

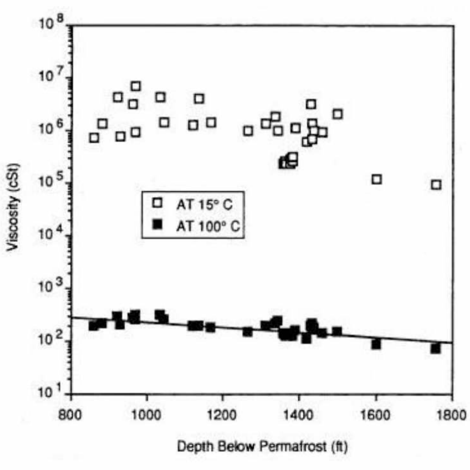

Figure 4: Ugnu Viscosity vs. Depth Below Permafrost with Effect of Temperature (Hallam et al. 1992)

High viscosity key properties and considerations include slow flow (wells produce at a lower rate than light oil wells). Also, waterflooding is less effective due to the viscosity contrast between heavy oil and water, and this is explored more later. Heavy oil can also tend to produce a lot of sand, however, slotted liners limit sand production into the wellbore. Extensive research has been done for sand-control strategies for ANS heavy oil developments (Burton et al. 2005). Heavy oil lends itself towards progressive cavity pump (PCP) applications with the multilateral design of up to 25,000 feet of completed laterals, however conventional well design with CHOPS has been used for early appraisals (Pospisil, 2011).

Ugnu oil is heavy and of low gravity. Hallam et al. state the gravity as 7.1 to 11.5° API, as well as a relationship with depth below the permafrost, indicating different degrees of biodegradation. A more recent document (Pospisil, 2011) puts the API gravity at 8° to 14° API and oil quality over 1,000 cp.

2.3 History Matching in Reservoir Simulation

If a reservoir simulation model is developed, the validity of the model is tested using it to simulate a field's output under past operating conditions. This is generally achieved by matching historical production data, such as oil vs. time in an oil reservoir, and comparing performance parameters such as gas/oil ratio (GOR), water/oil ratio (WOR), and reservoir pressure or bottom-hole well pressures. If there are substantial variations between the measured output and the well/reservoir system's established output, then changes are made to the reservoir simulation model to minimize this disparity. The process is called history matching and is essentially calibrating a reservoir simulation model. Figure 5 depicts an example of history matching.

If a history match is obtained, predictions of potential output of the well/reservoir are made under various operating scenarios. Owing to the uncertainty in the geological and reservoir simulation models for new areas, numerous predictions are also made with different reservoir parameters to assess the uncertainty in the forecasts. Multiple historically matched models based on different geological models and experimental designs can also be used to describe production forecast uncertainty (PetroWiki, Reservoir Simulation Applications).

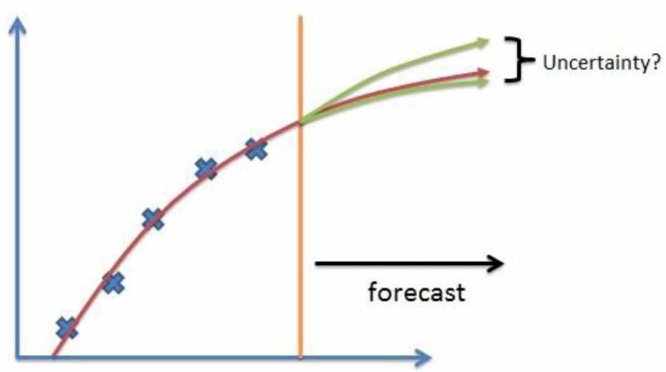

Figure 5: History Matching in Reservoir Simulation

(https://www.streamsim.com/sites/default/files/singlemodel1.png)

2.4 Water Flooding

Waterflood is a secondary recovery process in which water is pumped into the reservoir formation to displace oil. Injection water drives the displaced oil into nearby production wells. Problems with waterflood may involve inefficient recovery from early water breakthrough, resulting in a high water cut (Craig, 1971). This is common with heavy oil. Water flooding is the conventional EOR system used in the North Slope (and Mohanty) and is further improved by the abundance of low salinity aquifer water at Milne Point, rendering it affordable and a practical solution. While water flooding is a standard EOR solution for light oil, due to the unfavorable mobility ratio between injected water and reservoir oil, it is not recommended for heavy oil reservoirs. The injected water bypasses the native reservoir fluid and creates a finger-like flow pattern which leaves a large amount of oil unswept, a condition is called viscous fingering. Figure 6 depicts water flooding with an unfavorable mobility ratio.

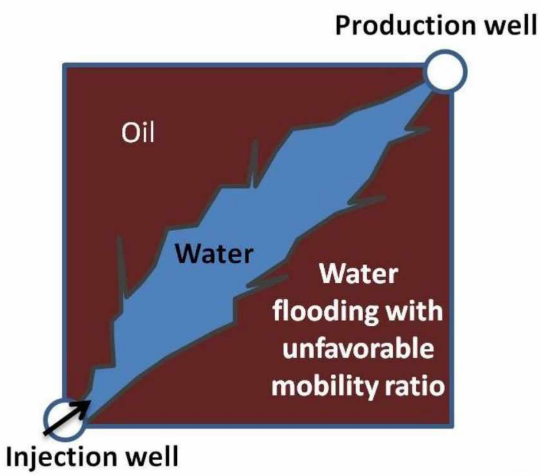

Figure 6: Water Flooding, adapted from large.stanford.edu/courses/2015/ph240/zerkalov1/

Mobility ratio (M) is defined as the ratio of mobility (λ) of the displacing fluid (water) to the mobility of the displaced fluid (oil), where mobility is effective permeability (κ) divided by viscosity (μ) of the same phase. With water as the displacing fluid, the mobility ratio can be defined as described in equation (1) (PetroWiki, Microscopic Efficiency of Waterflooding).

$$M = \frac{k_{rw}}{\mu_w}\frac{\mu_o}{k_{ro}}, \tag{1}$$

Where k_{rw} and k_{ro} are water relative permeability and oil relative permeability, μ_w and μ_o are water and oil viscosities, respectively.

It is important to note the mobility of the oil is defined ahead of the displacement front. However, that of the injectant is defined behind the displacement front. This ensures the respective effective permeability values are assessed at different saturations. The volumetric sweep efficiency and the mobility ratio have an inverse relationship, and the volumetric sweep efficiency can be described by equation (2).

$$E_V = E_A E_I, \tag{2}$$

Where E_A and E_I are the areal and vertical sweep efficiencies, respectively.

A mobility ratio (M) greater than one is unfavorable because this will cause the displacement mechanism to become unstable and the so-called "viscous fingering" effect. In the case of a significant difference in viscosity between the displacing fluid (water, lower viscosity) and the fluid being displaced (oil, higher viscosity), the mobility ratio would be greater than one, resulting in poor recovery. The fingering effect is strongly undesirable because it significantly expands on itself and decreases production. To decrease the mobility ratio below one, the approach of using viscous fluid (polymer) to increase the viscosity of displacing fluid has been developed - this approach is called polymer flooding and is discussed next.

2.5 Polymer Flooding

Polymer flooding is an enhanced oil recovery technique. Polymer flooding uses water with an increased viscosity by adding polymers. The viscosity is increased to reduce the mobility of the injectant and improve the mobility ratio which is defined as the mobility of the displacing fluid to that of the oil in place. Sweep efficiency is improved due to a reduced mobility ratio (PetroWiki, Polymer Waterflooding). The addition of polymers to water increases its viscosity and decreases the water permeability due to mechanical entrapment, thereby reducing its mobility. For more than 40 years, polymer flooding has been used to successfully extract the remaining oil from the reservoir, up to 30% of the original oil in place. Due to decreased water production and higher oil extraction, the overall cost of using the method of polymer flooding is lower than that of flooding with only water.

The two most used polymers are hydrolyzed polyacrylamide (HPAM) and xanthan. The procedure typically starts with pumping water containing surfactants to reduce the interfacial tension between the layers of oil and water, and to change the reservoir rock's wettability to enhance oil recovery. The polymer is then combined with water and continually pumped (can take several years) for a long period of time. When about 30 percent to 50 percent of the reservoir pore volume has been injected, the addition of polymer stops and the drive water is pumped into the injection to drive the polymer slug and the oil bank in front of it into the production wells (Abidin et al. 2012).

By reducing the mobility ratio within the reservoir, the EOR polymer flooding method increases recovery performance and efficiency. Polymer flooding can be the best choice for engaging with highly heterogeneous reservoirs such as unconsolidated sandstone and heavy oil reservoirs. Figure 7 shows the flooding of polymer with a desirable mobility ratio. This helps encourage smooth, uniform displacement of fluid and decreases the risk of viscous fingering effect, thus increasing the efficiency of oil recovery.

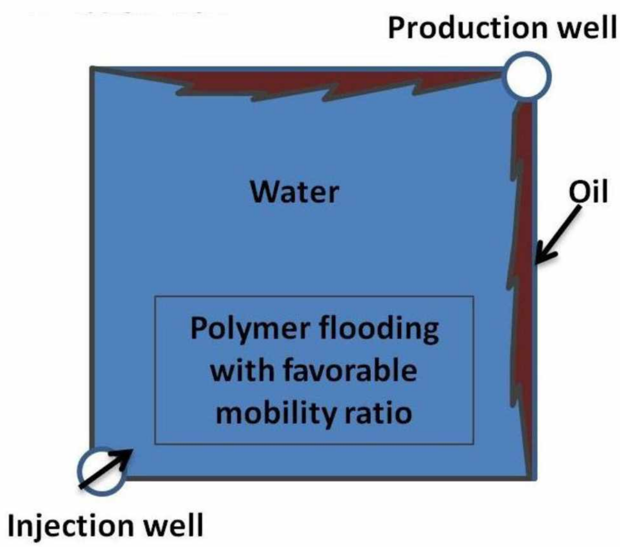

Figure 7: Polymer Flooding, from large.stanford.edu/courses/2015/ph240/zerkalov1/

Polymer retention in reservoir rock will often profoundly affect the technical and economic success of a polymer-flooding project. The amount of oil that will be recovered per pound of polymer injected is inversely related to polymer retention. Polymer retention should be determined carefully, or at least estimated carefully, before initiating a polymer waterflood. Polymer retention for a given polymer flood is normally best estimated by conducting flooding experiments in reservoir rock with reservoir fluids at reservoir temperature. Laboratory measurements of polymer retention in reservoir rock are usually reported as mass of polymer adsorbed per unit mass of rock and are usually reported as microgram/gram of polymer adsorbed onto reservoir rock (Huh et al. 1990). An equation for polymer retention is shown in equation (3), (Manichand and Seright, 2014).

$$R_{pret} = \{[\Sigma\ [(C_{poly}/C_{polyo} * \Delta PV) - (C_{trac}/C_{traco} * \Delta PV)]] + IAPV\} * C_{polyo} * PV / M_{rock} \tag{3}$$

Here, C_{poly} is the effluent polymer concentration, C_{trac} is effluent tracer concentration, C_{polyo} is the injected polymer concentration, C_{traco} is the injected tracer concentration, PV is the volume in one pore volume, ΔPV is the pore-volume increment, and M_{rock} is the rock mass in the core.

Polymer adsorption results primarily from physical adsorption and not chemisorption. Polymer adsorption is often the major cause of polymer retention. Figure 8 depicts polymer retention and shows the two dominant mechanisms of retention: (1) adsorption on the surface of large pores, and (2) the mechanical entrapment in small pores.

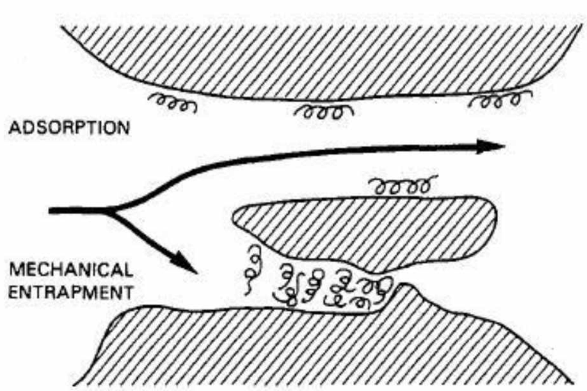

Figure 8: Polymer Retention (Huh et al. 1990)

2.6 Current Milne Point Unit Polymer Flood Pilot

There has been a polymer-flood pilot ongoing in the Milne Point Unit (MPU), supported by the Department of Energy and administered by the National Energy Technology Laboratory (Dandekar et al. 2019). A collaboration between government, academia, and industry, participation included not limited to the Department of Energy, UAF, and Hilcorp Alaska. This polymer flood field pilot was the first-ever on Alaska's North Slope and the authors felt the pilot could be a "game-changer" to enhance the recovery of heavy oils. The goal of the project was to validate the use of polymer floods for enhanced heavy oil recovery on Alaska's North Slope.

The pilot area contains two horizontal injectors and two horizontal producers, with laterals in the range of 5,000 ft. Before the pilot, the pattern was waterflood and resulted in an oil recovery of 7.6% and a water cut as high as 67%. The reservoir characteristics in the pilot area are favorable to polymer injection with formation porosity and permeability in the range of 30-35%, and 100-3000 mD respectively. The low reservoir temperature is 70°F, oil undersaturated with an API of ~15°, and in-situ oil viscosity of ~300 cP. Polymer mixing and pumping facilities injected HPAM. The HPAM is shipped in powder form, with sacks of 1650 lbs. The polymer powder is mixed with water through a hopper system, then injected with positive displacement pumps. Source water was low salinity at 5,000 ppm. The target viscosity was 45 cP and required polymer concentration between 1,600 and 1,800 ppm (parts per million). The functionality of the polymer mixing and pumping facility was successful, for the first time in a remote Arctic environment. No injectivities issues or polymer breakthrough were encountered after five months of polymer injection. Lab tests revealed moderate polymer retention values of 28 micrograms per gram of reservoir rock. Other details were discussed including the mixing unit (referred to as the Polymer Slicing Unit), laboratory core floods, and treatment of effluent stream containing produced oil, water, and polymer. An acceptable separation of oil and water, especially when spent polymers were present, was a challenge and needed further research.

The authors concluded this research will assist in a shift towards enhancing the recovery of heavy oils on Alaska's North Slope through polymer flood. Benefits include 8-10% OOIP recovery increment over waterflooding, extending the life of the Trans-Alaska Pipeline System, and creating environmentally friendly EOR methods. At the time of writing, the pilot study is ongoing. In an unreferenced 2020 update by the authors made available for this project, several updated conclusions have been made. Conclusions include after 1.5 years, no polymer breakthrough or severe injectivity issues have been recorded and obtaining polymer retention values continue to be a challenge.

Conclusions in the 2020 update include cautious optimism that the positive trend of steady progress and promising indications of the pilot will continue and the author's original conclusion of polymers being a game changer to enhance the recovery of heavy oils on Alaska's North Slope will stand. According to a project Gantt chart available on the National Energy Technology's website (Barnes J, 2018), the project is ongoing with pilot-scale validating and recommendation for polymer flooding scheduled to occur in 2021 and 2022.

CHAPTER 3 FIELD DATA PROVIDED BY HILCORP

Information provided by Hilcorp included the reservoir model, WELL-3 historical production data, Pressure-Volume-Temperature (PVT), relative permeability, and capillary pressure data.

3.1 Reservoir Model

The RESCUE model was provided by the geologist. RESCUE is a joint industry project managed by the Petrotechnical Open Software Corporation (POSC). The acronym 'RESCUE' stands for Reservoir Characterization Using Epicenter. It forms the basis of the standard for the transfer of data from geomodels to upscalers. In this case, the RESCUE model provided array properties information to Builder such as Grid Bottom, Grid Centroid X, Grid Centroid Y, Grid Paydepth, Grid Thickness, and Grid Top. The RESCUE format model defined "block units" (formed by 3D surfaces representing horizons, boundaries, and fault surfaces), 3D grids, and properties such as porosity and permeability.

The MB sands were specified in the RESCUE model and were selected to import into the Builder model. RESCUE properties including horizontal permeability, null blocks, and porosity were mapped into CMG properties. Both permeability and porosity were included within the model. Porosity was based on log data and permeability was calculated using a porosity-permeability correlation which was developed using core data in the Ugnu reservoir. The RESCUE model also contained NULL blocks. Sand is 1 and 0 were the null values. The RESCUE model also included the necessary well trajectories, as shown in Figure 9 and described in Table 1. Figure 9 shows a middle layer of the reservoir and horizontal permeability. Table 1 pertains to the four wells in Figure 9. The first iteration of the RESCUE grid contained block units with an areal dimension of 250x250 feet which was later considered too large. The second iteration of the RESCUE grid contained block units with an areal dimension of 100x100 feet. This dimension was considered fine enough, and the simulation did not behave in a manner that would indicate the need for smaller block units. Reservoir model revision history is as follows:

- Version 1 (December 27th, 2019) – Included WELL-3, 250’x250’ x 2’ thick block units
- V2 (January 9th, 2020) – Revised major dimension block units to 100’x100’x2’ thick
- V3 (February 19th, 2020) – Refined porosity and permeability values, other 3 wells
- V4 (February 25th, 2020) – Final Model, permeability truncated at 10,000 mD

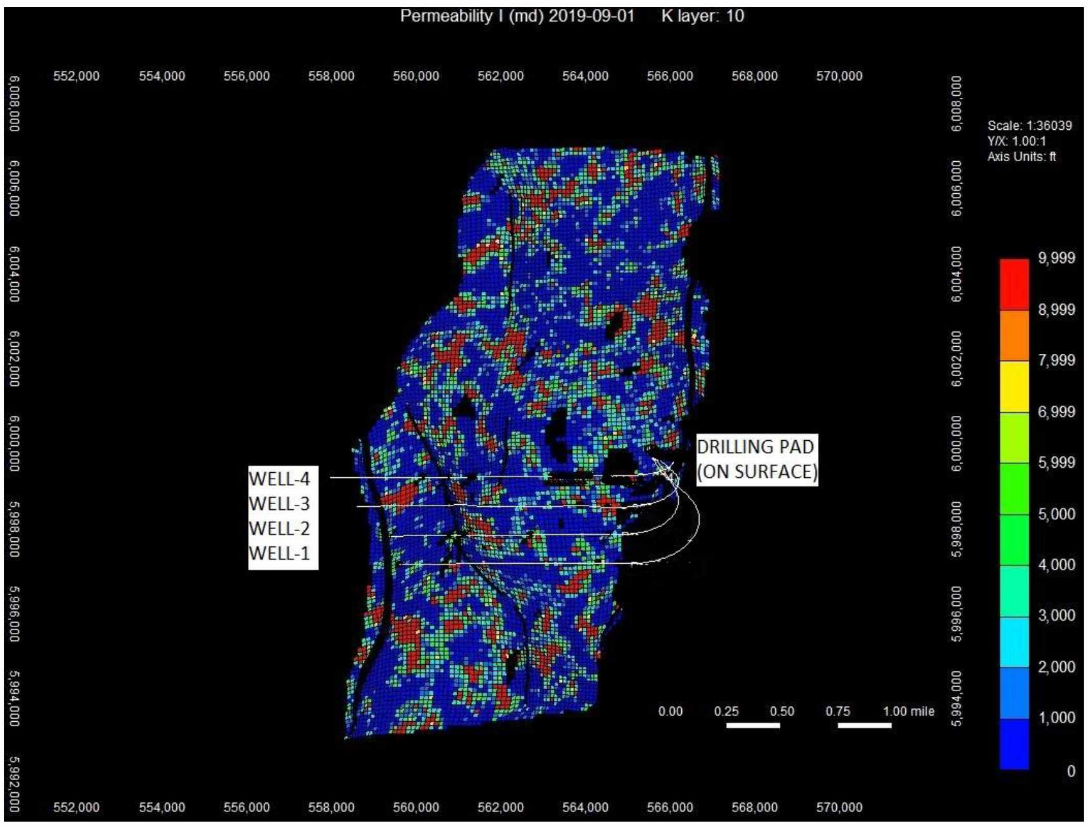

Figure 9: Reservoir Gridding & Well Trajectories. Inter-well distance is roughly 700 feet.

Table 1: Well Summary

Well:	Producer/Injector:	Existing/Proposed:	Online Date:
WELL-1	Producer	Proposed	2020-08-01
WELL-2	Injector	Proposed	2020-07-01
WELL-3	Producer	Existing	2019-09-28
WELL-4	Injector	Proposed	2020-09-01

3.2 Historical Production Data

Production history data for WELL-3 was provided in tabular form for input into Builder. Plots of the tabular data are depicted in Figure 10 (production) and Figure 11 (Bottomhole pressure). The cyclic data that occurs and repeats roughly three times before 11/15/2019 is due to the pump stopping for a short duration (less than a full day), slightly decreasing the daily oil production rate for that day and leading to an increase in well bottom-hole pressure. Also, there is a sudden change in water-cut from 11/15/2019 due to well test uncertainties and likely errors. Since the well is lifted by a jet pump powered by water, the water cut is uncertain. The water cut jump is assumed not to be an actual occurrence. The actual history match is up until 11/15/2019 to avoid this uncertainty.

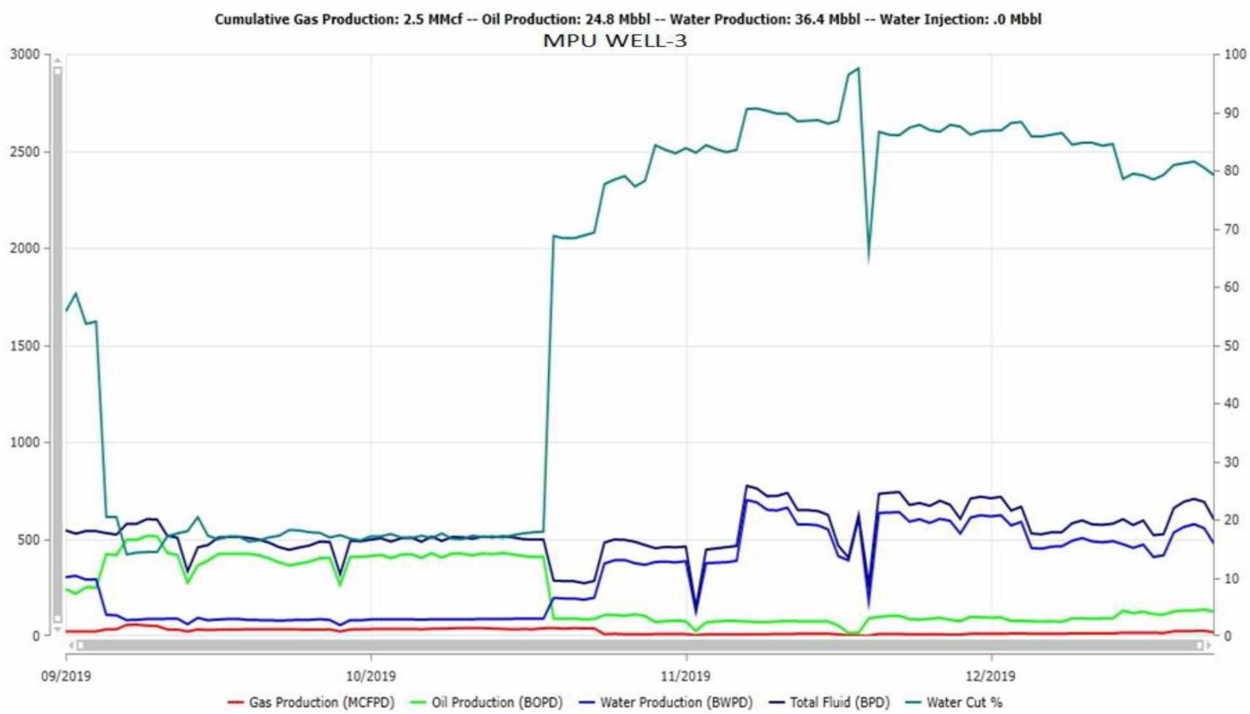

Figure 10: WELL-3 Historical Production Data for History Matching

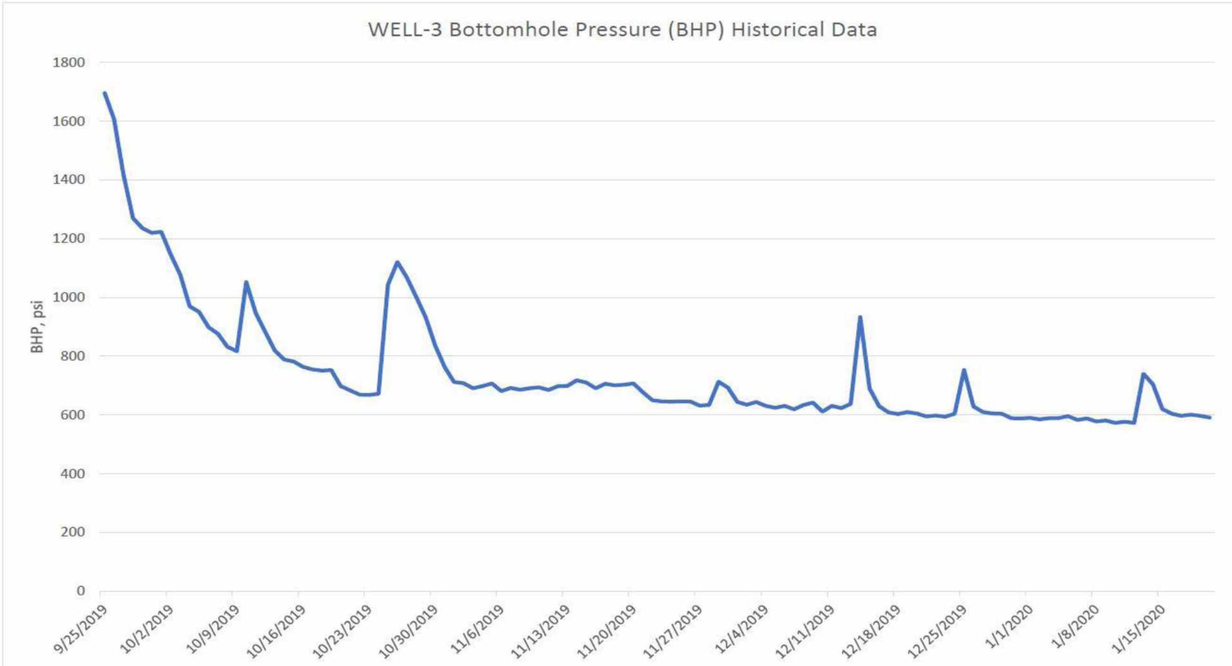

Figure 11: WELL-3 Historical Bottomhole Pressure Data for History Matching

3.3 PVT Data

PVT data to be used in the model was generated by the reservoir engineer using correlations developed based on proprietary PVT lab data. The geologist also assisted, and the PVT data was reflected in subsurface overviews and field development plans. Supplied properties included oil gravity, reservoir temperature, bubble-point, initial solution gas/oil ratio, and the dead oil viscosity. Saturated and undersaturated fluid properties were supplied as well. The below data was input into Builder for the history match and the simulations.

Table 2 shows the general PVT data. The pressure is ‘p’. Rs is solution gas-oil ratio for saturated oil at pressure ‘p’, Bo is the formation volume factor for saturated oil at pressure ‘p’, Eg is the gas expansion factor for condensate saturated gas at pressure ‘p’, viso is the viscosity of saturated oil at pressure ‘p’, and visg is the gas viscosity for condensate saturated gas at pressure 'p'. One of the key parameters in this table is the high oil viscosity cp, consistent with Ugnu heavy oil.

Table 2: PVT Data Table Inputted into Builder

#	p	Rs	Bo	Eg	viso	visg
	psi	ft3/bbl		ft3/bbl	cp	cp
1	14.7	0	1	5.49086	7502.59	0.010643
2	200	22.29	1.0093	41.4512	5291.19	0.010749
3	485.8	51.83	1.0189	199.913	3413.29	0.011454
4	956.9	96.85	1.0336	437.166	1838.68	0.01291
5	1051.12	105.31	1.0363	490.275	1647.19	0.013294
6	1145.34	113.58	1.039	545.128	1481.81	0.013712
7	1189.48	117.4	1.0403	601.529	1412.13	0.014166
8	1239.56	121.68	1.0417	717.766	1338.41	0.015183
9	1742.4	161.78	1.0547	914.006	827.36	0.017166
10	2056.8	184.22	1.062	1099.14	642.35	0.019383
11	2371.2	204.62	1.0686	1262.84	515.03	0.021666
12	2685.6	222.99	1.0746	1402.61	425.17	0.023889
13	3000	239.33	1.0799	1520.5	360.48	0.025985
14	4000	277.8	1.0925	1638.39	249.19	0.028082
15	5000	295.73	1.0983	1756.28	211.66	0.030178

Table 3 shows the oil formation volume factor above the bubble point as a function of pressure, and the first entry in Table 3 is the oil formation volume factor value at the bubble point pressure. All subsequent pressure entries are greater than this bubble point pressure and increase in a monotonic fashion. The software will determine if Table 2 or Table 3 will be used to find B_o, based on the calculated pressure, density, and bubble point pressure in a simulation block. A complete explanation can be found upon review of the *BOTAPI simulation keyword.

Table 3: Oil Formation Volume Factor above the Bubble Point as a Function of Pressure and Oil Density

#	p	Bo
	psi	
1	1189.48	1.0403
2	1742.4	1.0356
3	2056.8	1.033
4	2371.2	1.0304
5	2685.6	1.0278
6	3000	1.0252
7	4000	1.0169
8	5000	1.0087

Table 4 shows oil viscosity and its use in CMG signals the input of the pressure dependence of oil viscosity above the bubble point pressure and operates in much the same way as Table 3.

Table 4: Oil Viscosity above the Bubble Point as Function of Pressure and Oil Density

#	p	viso
	psi	cp
1	1189.48	1412.13
2	1742.4	1806.85
3	2056.8	2036.3
4	2371.2	2276.04
5	2685.6	2530.5
6	3000	2803.95
7	4000	3853.18
8	5000	5321.67

3.4 Relative Permeability Data

Relative permeability data to be used in the model was initially generated and provided by the reservoir engineer. Figure 12 shows the oil-water relative permeability input into Builder. Curve smoothing as recommended by CMG Builder was applied. The supplied data was sparse, and the curve smoothing technique applied produced the best fit to an analytical power-law model over the entire range of data. The smoothing technique ensures the matching of the original data at critical points and re-interpolates the original input using equal spacing. CMG used power-law smoothing with Corey exponents and took the form of equation 5 for K_{rw} and equation 6 for K_{row}, where K_{rw} is the relative permeability to water (fraction) at a given water saturation, and K_{row} is the relative permeability to oil (fraction) in the presence of the given water saturation. S_{wcit} is critical saturation, S_{oirw} is irreducible oil saturation, S_{orw} is residual oil saturation, S_{wcon} is connate water saturation. Pkrw and pkrow are the power-law exponents for K_{rw} and K_{row} respectively.

$$K_{rw} = K_{rwiro}\left(\frac{S_w - S_{wcrit}}{1 - S_{wcrit} - S_{orw}}\right)^{pkrw} \tag{5}$$

$$K_{row} = K_{rocw}\left(\frac{1 - S_{orw} - S_w}{1 - S_{wcon} - S_{orw}}\right)^{pkrow} \tag{6}$$

For Liquid-Gas relative permeability, curve smoothing as recommended by CMG Builder was also applied. The result is shown in Figure 13. For Liquid-Gas relative permeability, the critical gas saturation was adjusted from 0.04 to 0.12 via keyword in the array data. This was done to reduce the gas-oil ratio for history matching and is not reflected in Figure 13.

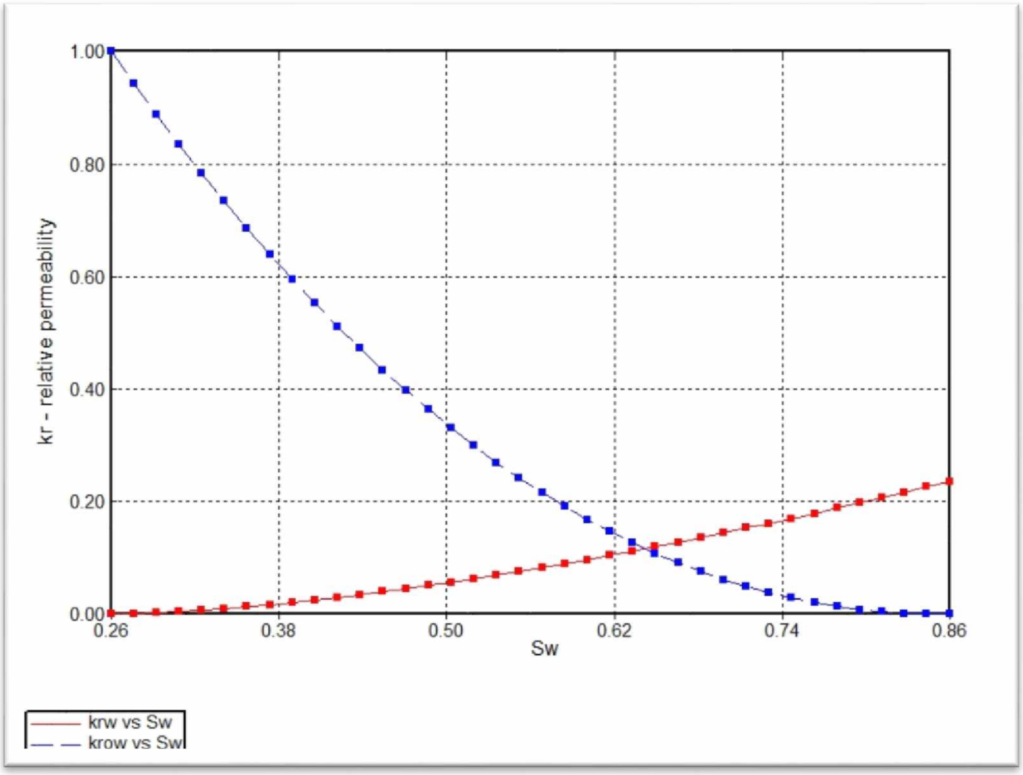

Figure 12: Oil-Water Relative Permeability Curve

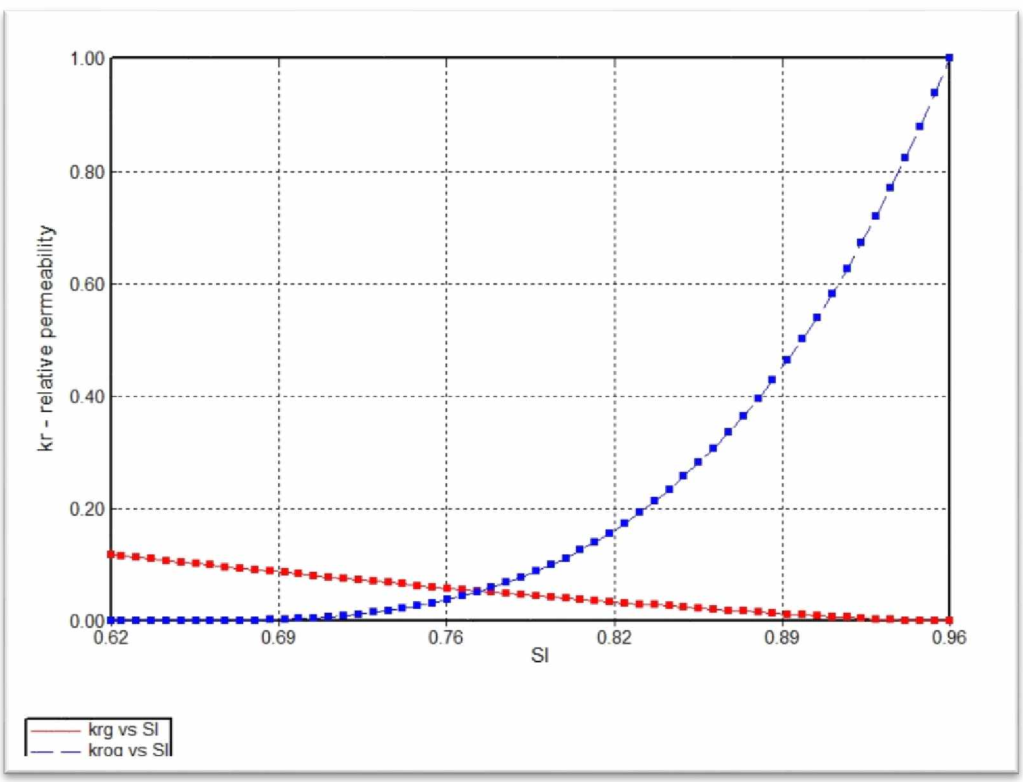

Figure 13: Liquid-Gas Relative Permeability Curve

3.5 Capillary Pressure Data

A capillary pressure curve from another well in the Milne Point field was used to initialize a water-oil contact transition zone. Previous unsuccessful measures to initialize the zone included setting the critical water saturation below the initial water saturation as well as setting the water-oil-contact below the reservoir. Interpolation was necessary to find the corresponding Pcow values for the Sw values in the relative permeability range and is presented in Figure 14. After the capillary pressure curve data was inputted water was able to move at the initial condition in the transition zone. This transitional water-oil contact led to stabilization in water cuts and the gas-oil ratio, assisting in better history match. A cross-section of the production zone is depicted in Figure 15. Initial water saturation ranges from approximately 26-28%. The well shown is WELL-3. 2019-Sep-01 is the beginning of the simulation.

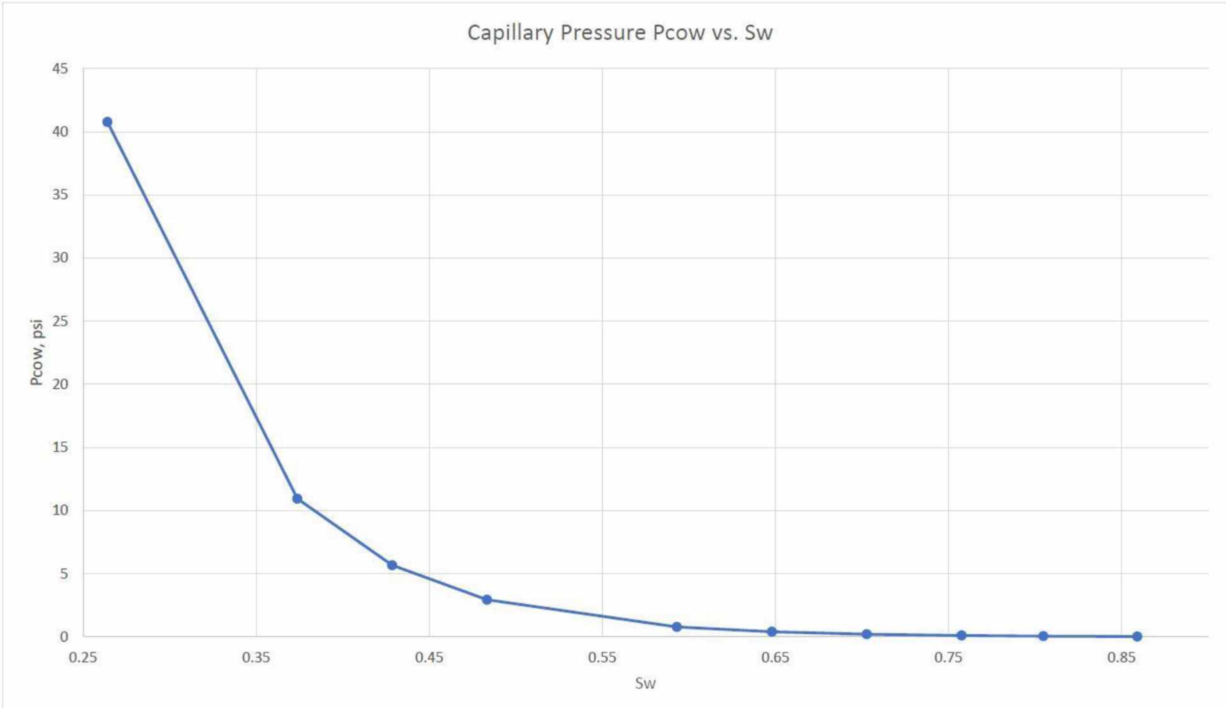

Figure 14: Capillary Pressure Curve

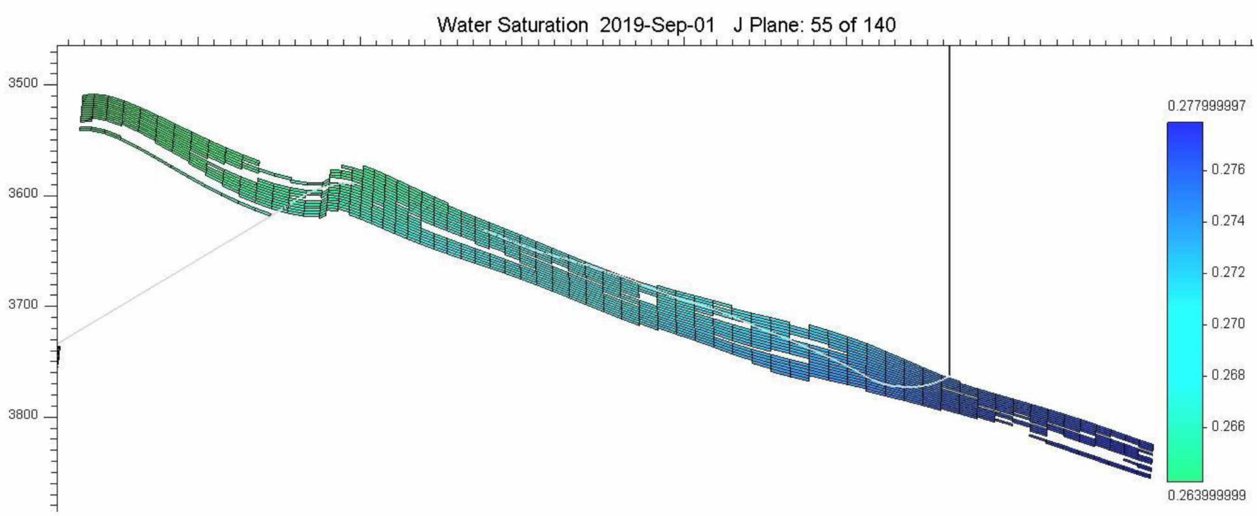

Figure 15: Water-Oil Transition Zone Initialization

CHAPTER 4 METHODS

4.1 Software and Logistics

The CMG reservoir simulation software package was used for the numerical reservoir simulation. CMG Builder was used as a Pre-Processor to build the simulation model. Builder simplifies the creation of simulation models by providing a framework for data integration and workflow management between IMEX and external data sources. The interactive, intuitive, and easy-to-use interface enables the users to quickly and efficiently incorporate all required data to build a simulation model.

CMG IMEX is a black oil and unconventional simulator which models primary and secondary recovery techniques for conventional and unconventional oil/gas reservoirs. IMEX can model simple to structurally complex, heterogeneous, oil and gas reservoirs, using small to very large scale multi-million grid cell models to achieve reliable production forecasts.

The simulation was run on a mid-range consumer computer but capable of handling small to medium size simulations with adequate speed. Simulation run-time was an early concern, however, the run-times for all simulations were satisfactory, with history match simulation run-times in the proximity of five minutes.

4.2 Well Properties

Typical well properties included perforations in all penetrated grids and a wellbore radius of 0.354 ft for 8.5” bit. A larger skin factor (50) was applied to production wells to reduce gas breaking out close to the wellbore region to assist with the history match. Skin factor, ‘s’, is a numerical value used to analytically model the difference from pressure drop predicted by Darcy’s law due to skin. Equation 4 gives the pressure drop (PetroWiki, Fluid Flow with Formation Damage).

$$\Delta p_s = \frac{141.2 q B \mu}{kh} s \ . \tag{4}$$

Where Δp_s is the pressure drop due to skin, ‘s’ is the skin factor and other symbols per typical petroleum engineering convention.

4.3 Critical Gas Saturation Adjustments

Critical gas saturation originally was 4% from the liquid-gas relative permeability. Simulations using 4% critical gas saturation lead to instabilities and large gas-oil ratio swings in mid-2020, beyond historical data. This value was increased to 12% using the *TSGCRIT keyword below array data.

4.4 Initialization

Initial Conditions were set for the simulation model. Initial conditions input included performing a gravity-capillary equilibrium of a reservoir initially containing water and oil. Reference Pressure and Depth was input as 1,602.1 psi and 3,700 feet, respectively. This corresponds to a normal hydrostatic pressure gradient of 0.433 psi/ft. Water-oil contact was set to 5,875 feet depth to achieve the necessary initialization and history match.

4.5 Sector Area for Study

A sector “Sector1” was created to view results within a geological area, especially the oil recovery factor. This was done using Builder’s sector/polygon tool. Figure 16 below shows the extents of the sector, which is an estimate of the drainage area. Sector1 allows the utilization of a function of Builder software which enables the user to create an area sector and through layers to analyze that area in more detail. The sector is comprised of all layers in the reservoir model, vertically from top to bottom.

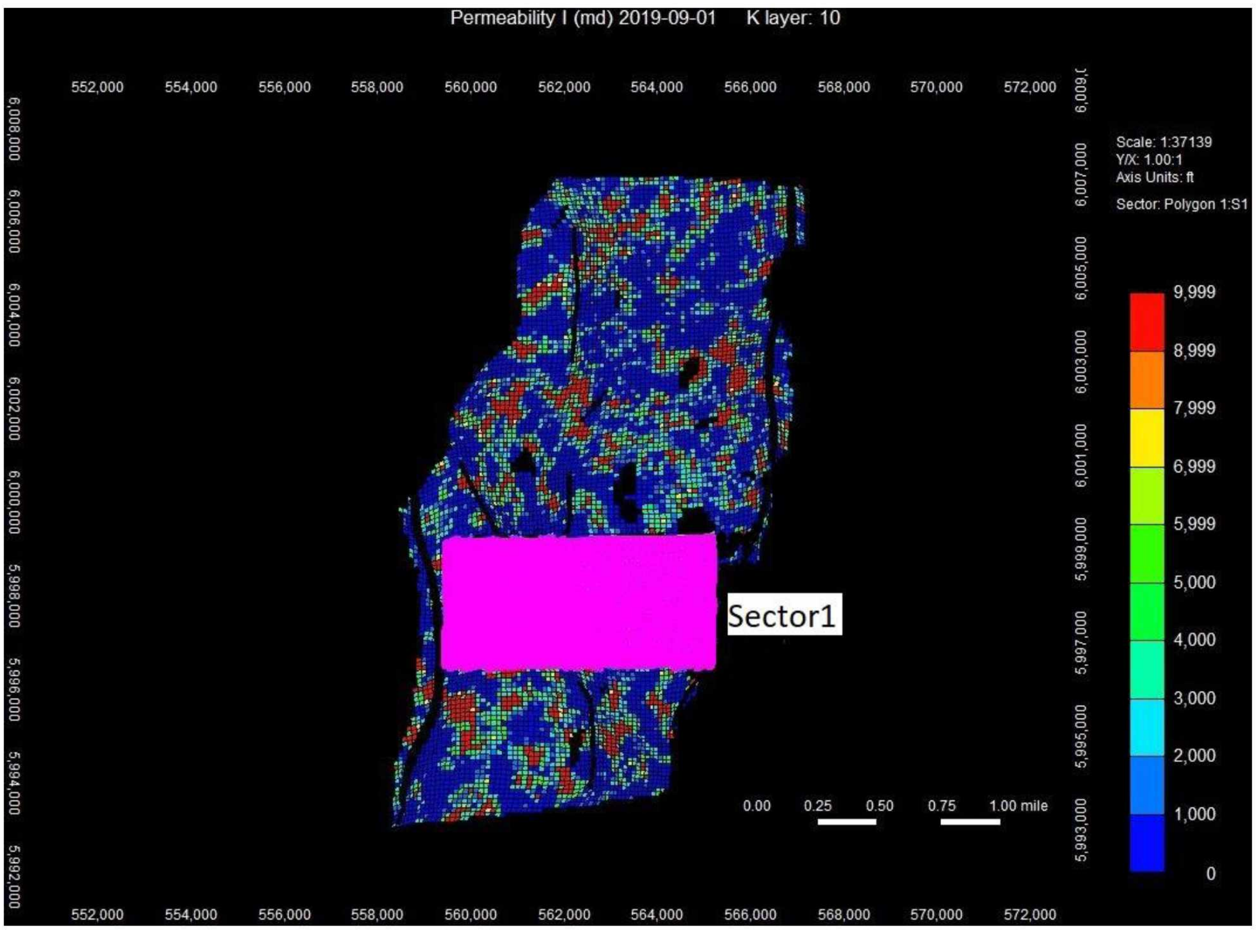

Figure 16: Sector1 Area of Study

4.6 History Matching

History matching methods reflected common industry history match methods explored in the Literature Review (Chapter 2.3). Primary recovery with exclusively WELL-3 was history matched. In general, the parameters adjusted for the history match included well skin, porosity, and permeability, water-oil contact level, critical gas saturation. If the simulated gas-oil ratio was high, critical gas saturation was reduced and skin factor was added to the production well. The final history match resulted in a skin factor of 50 on Well-3. If higher liquids flow were simulated vs actual, then permeability was reduced. If an unwanted high water cut was seen, then water-oil contact depth was lowered in the model. In early model iterations, gas-oil ratio rates were spiking at late times. To combat this, critical gas saturation was increased through curve scaling in the relative permeability tables. There was a continuing issue on early model iterations on the matter of permeability and porosity values. Model revisions were used to refine permeability and porosity values to succeed in a history match. No figures are presented in this report of simulations conducted before a successful history match. After the history match was successful, simulation predictions of approximately 30 years were carried out through 8/30/2049.

- As discussed in Chapter 3.2 on historical production data, there are anomalies in the historical data (primarily water production) past 11/14/2019, therefore the history match essentially used data from September 2019 to 11/14/2019.
- Oil Rate was the primary constraint for history match until 11/14/2019, refer to Figure 17. Other constraints seen in Figure 18 through Figure 21 were considered secondary and history matched through an iterative process. The oil rate from 11/15/2019 to 01/20/2020 was not included in the history match.
- Liquid Rate was the primary matching constraint past 11/14/2019, refer to Figure 18.

- Water-Oil contact was adjusted within the model until the appropriate water-cut match was observed (10-20%), the higher water cut after 11/14/2019 is considered due to well-test uncertainties. See Figures 14 and 15.
- GOR history matching included limiting variations of GOR seen in historical production data. The GOR history match achieved is seen in Figure 20.
- Bottomhole pressure was the last parameter to be matched, the matching process was iterative and included adjusting reservoir permeability, skin, and monitoring corresponding liquid and oil rates. See Figure 21.

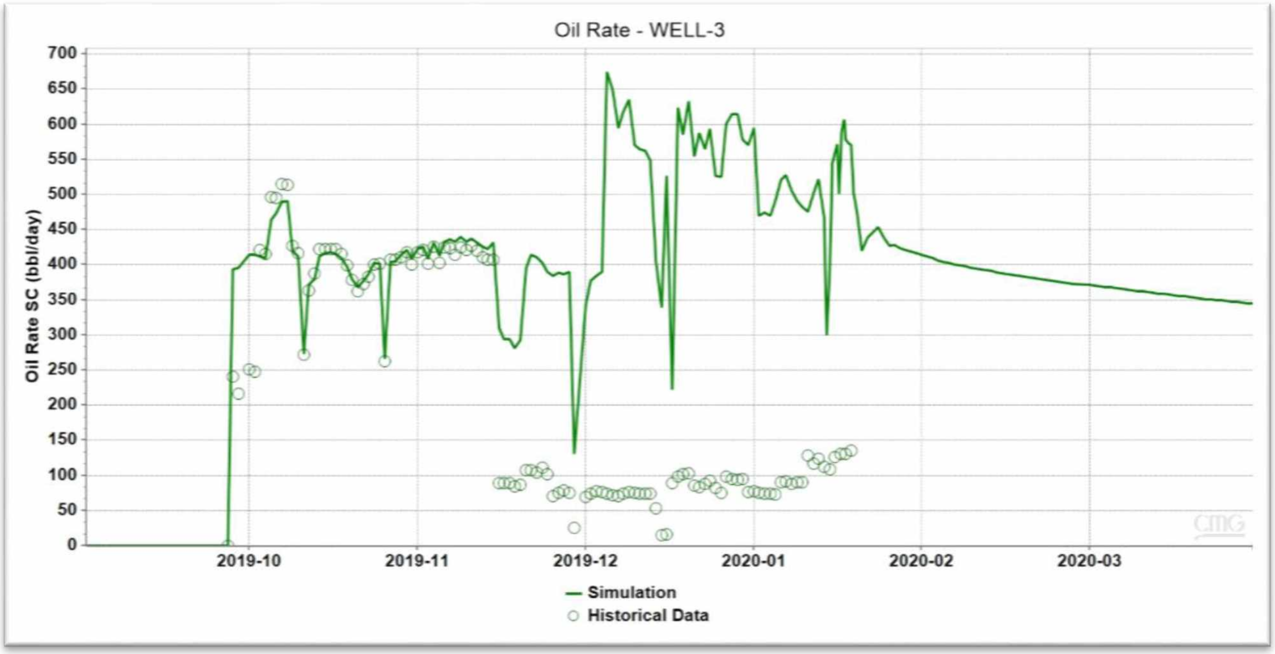

Figure 17: History Match of Oil Rate

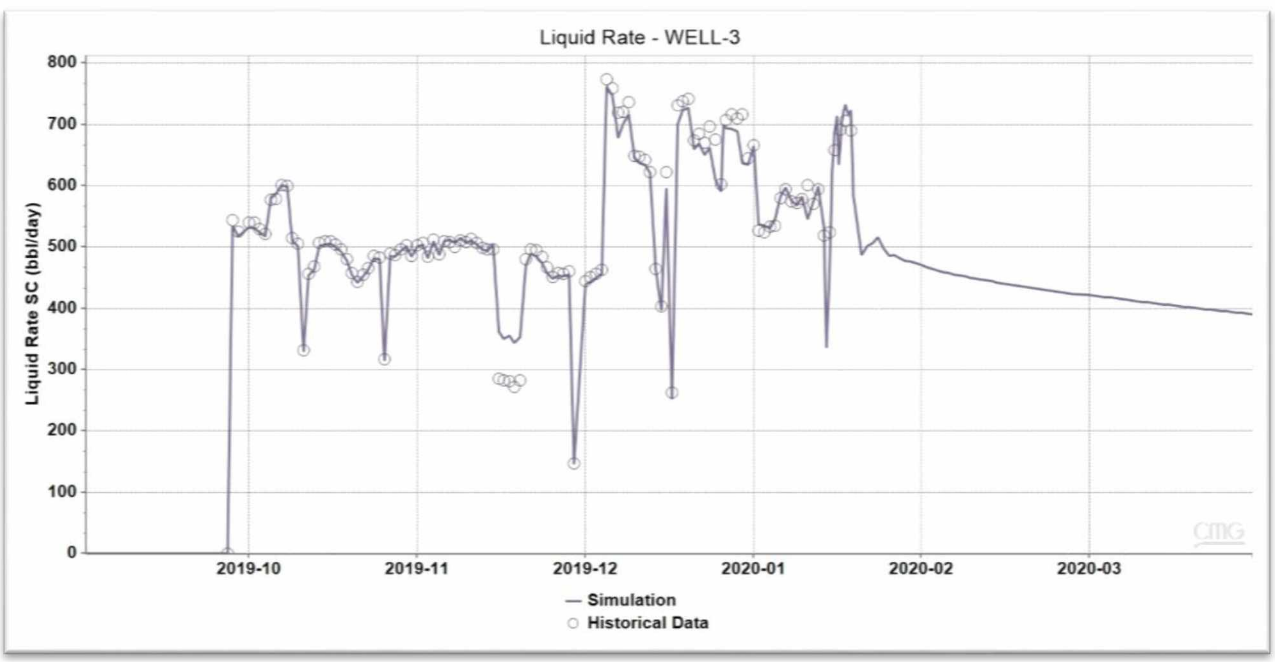

Figure 18: History Match of Liquid Rate

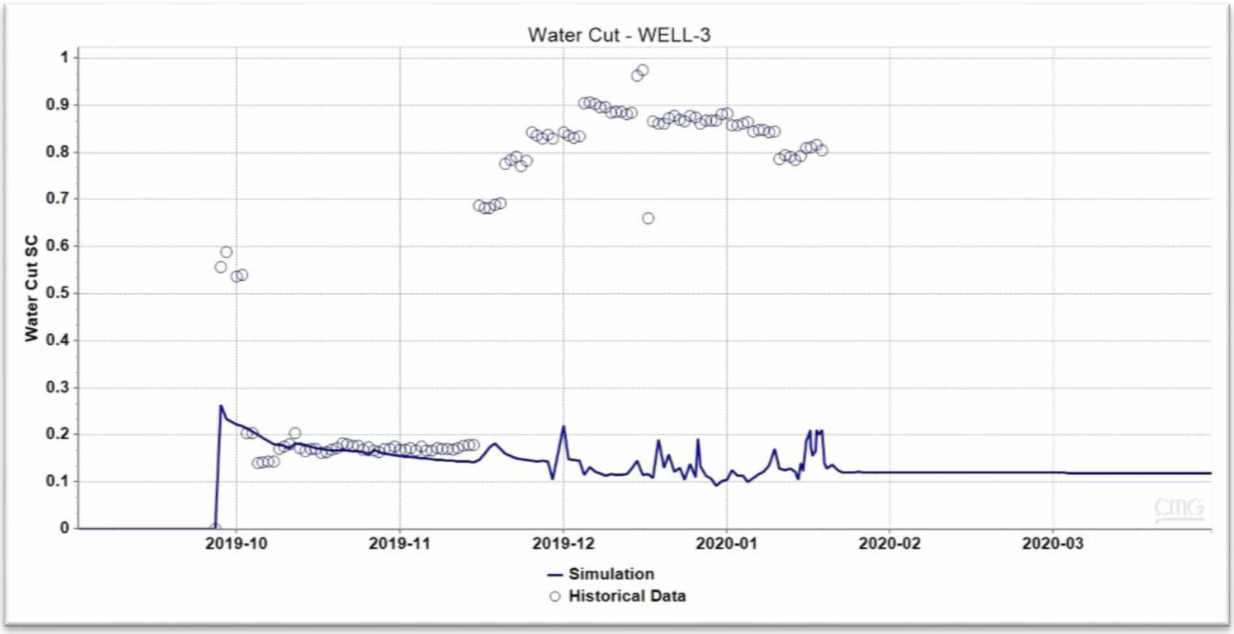

Figure 19: History Match of Water Cut

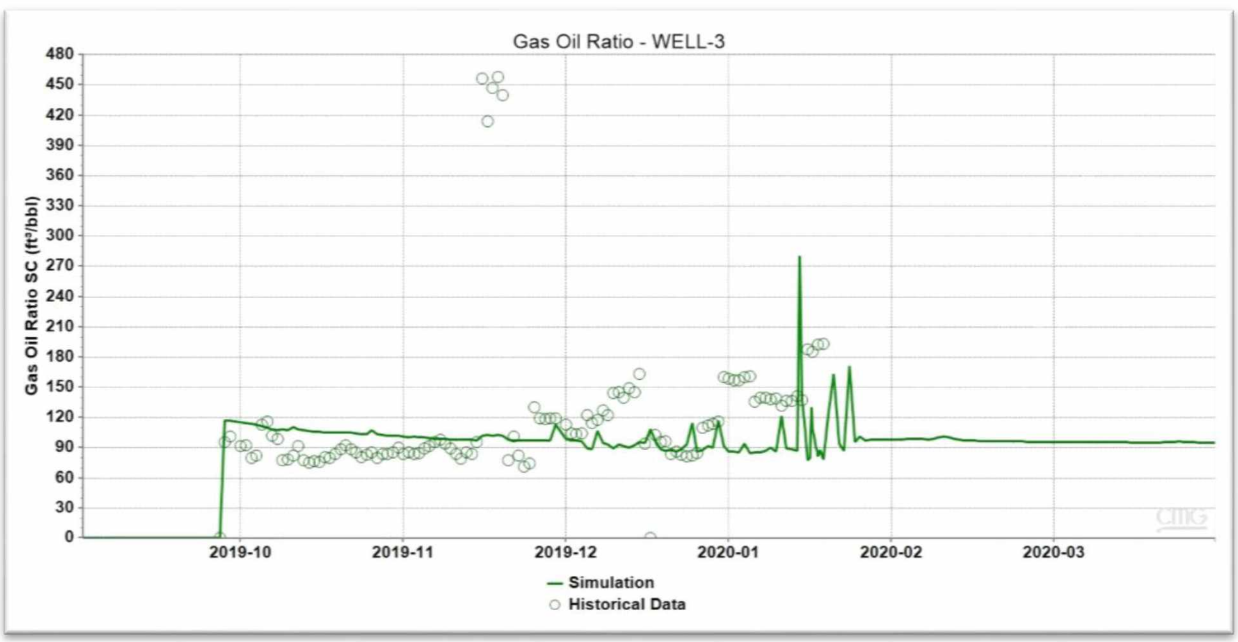

Figure 20: History Match of Gas-Oil Ratio

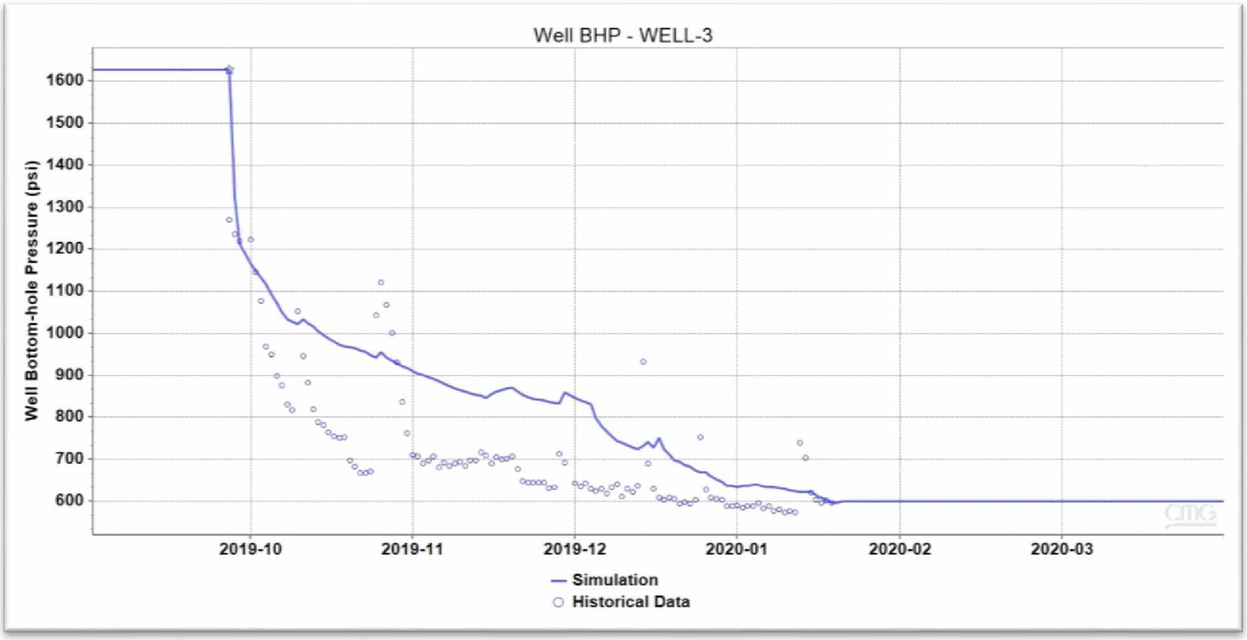

Figure 21: History Match of Bottomhole Pressure

4.7 Waterflood

Waterflood was simulated through the respective injection wells and setting target injector rates. Target rates were set to match maximum liquid production rates, at 1500 bbl/day. The logic in this was to provide a simple volume balance to the reservoir, with liquid in matching liquid out. No target pressure was set within the model. Detailed water salinities or viscosities were not considered, and the Builder software's default injection water properties were used.

4.8 Polymer Flood

The two most used polymers are hydrolyzed polyacrylamide (HPAM) and xanthan. This study assumed the injection of HPAM and compared the results of three different polymer strategies as depicted in Table 5. HPAM is the popular synthetic polymer in most of the polymer flooding processes. The *PISV *PREFCONC values used are approximate values from a lab measured viscosity-concentration curve for Milne Point. Conversion from lb/bbl to ppm includes a conversion factor of (10^6)/(42*8.34), where 42 is gallons per barrel and 8.34 is approximate pounds per gallon. This corresponds to approximately 0.35 lb/bbl = 1,000 ppm. Slug injection followed by water drive was not considered in this study. Polymer retention input to the simulator was 0.02808 pounds per barrel or 30 micrograms per gram of rock, a value provided from comparison cases.

Table 5: Polymer Flood Simulator Input Summary

	Polymer Viscosity	Polymer Concentration (Injection)		Polymer Retention
Keyword:	*PVISC	*PREFCONC	--	--
Unit:	cp	lb/bbl	ppm	µg/gram
100cp Polymer Flood Study:	100	1.0	2,855	30
50cp Polymer Flood Study:	50	0.7	1,998	30
20cp Polymer Flood Study:	20	0.4	1,142	30

CHAPTER 5 CONSTRAINTS FOR PREDICTIONS

5.1 Maximum Surface Liquid Rate Constraints

Maximum Surface Liquid Rates were set to 1500 bbl/day liquid per well. This constraint came from maximum rates from nearby comparison wells. This constraint was applied to all four wells and was applied at the beginning of the simulation prediction when additional wells came online. The constraint parameter name in Builder for this is STL surface liquid rate for producers and SWT surface water rate for injectors. The simulation could be easily re-run if field conditions are different and actual maximum liquid capacity rates were higher or lower than 1500 bbl/day, as was done in Chapter 6.6

5.2 Bottomhole Pressure Constraints

The minimum bottom-hole pressure on producing wells was set to 600 psi. This constraint is approximately the lowest bottom hole pressure of WELL-3's historical data. Injection wells have no minimum bottomhole pressure constraints, instead, they have maximum bottomhole pressure. Injection wells were set to have a max BHP of 2200 psi. The BHP bottom hole pressure parameter is used for both producers and injectors.

5.3 Other Well Constraints

Other applied constraints included general well events such as shut-in constraints until the date the well is online and automatic constraints generated by Builder applied to wells from the import of WELL-3 historical production data, including STO surface oil rate, STG surface gas rate, SWT surface water rate.

CHAPTER 6 PREDICTION RESULTS AND DISCUSSION

6.1 Prediction Results

Predictions were simulated for approximately 30 years, through 8/30/2049. General discussion of results immediately follows the prediction results depicted in Figures 22-32, see section 6.2.

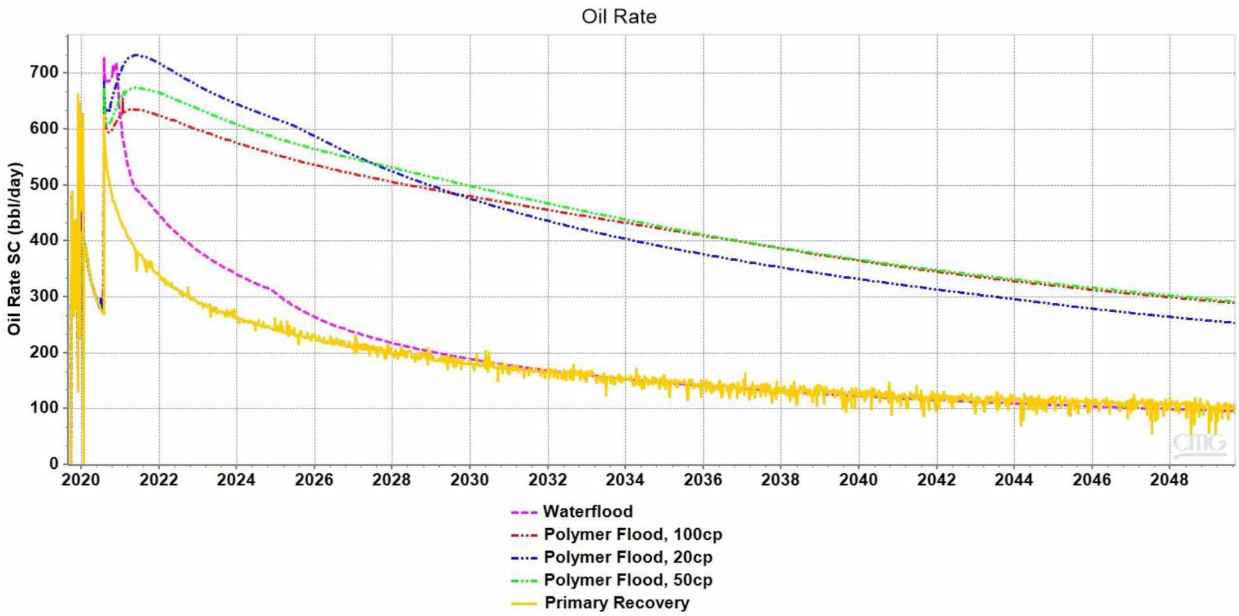

Figure 22: Prediction of Oil Rate

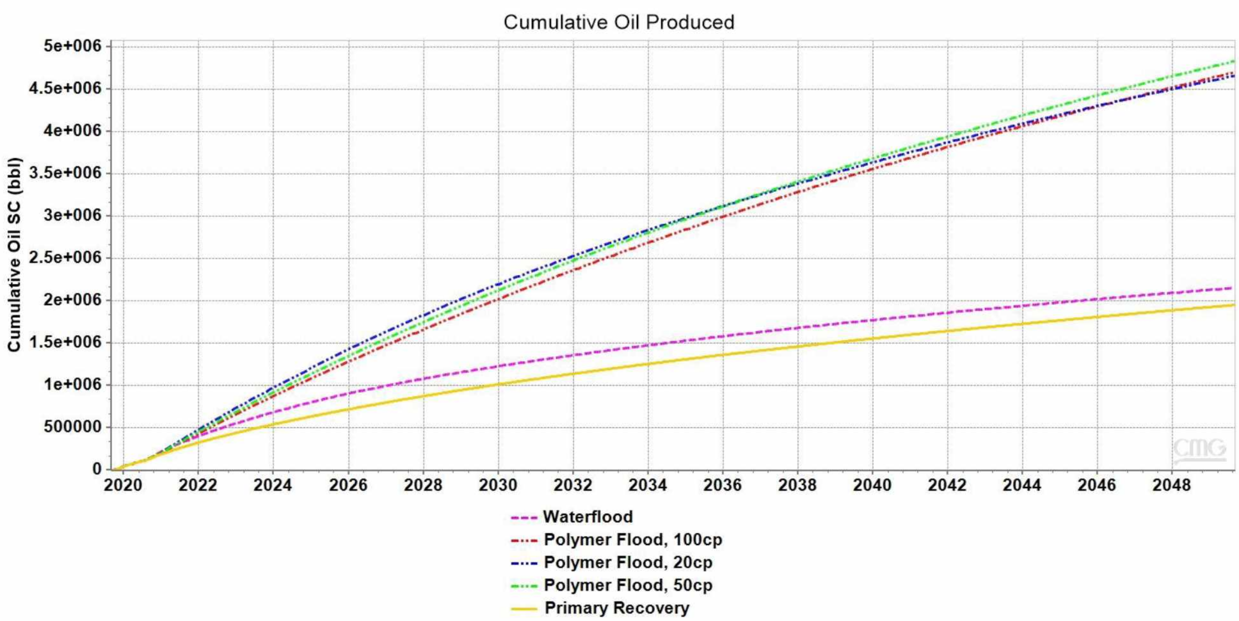

Figure 23: Prediction of Cumulative Oil Produced

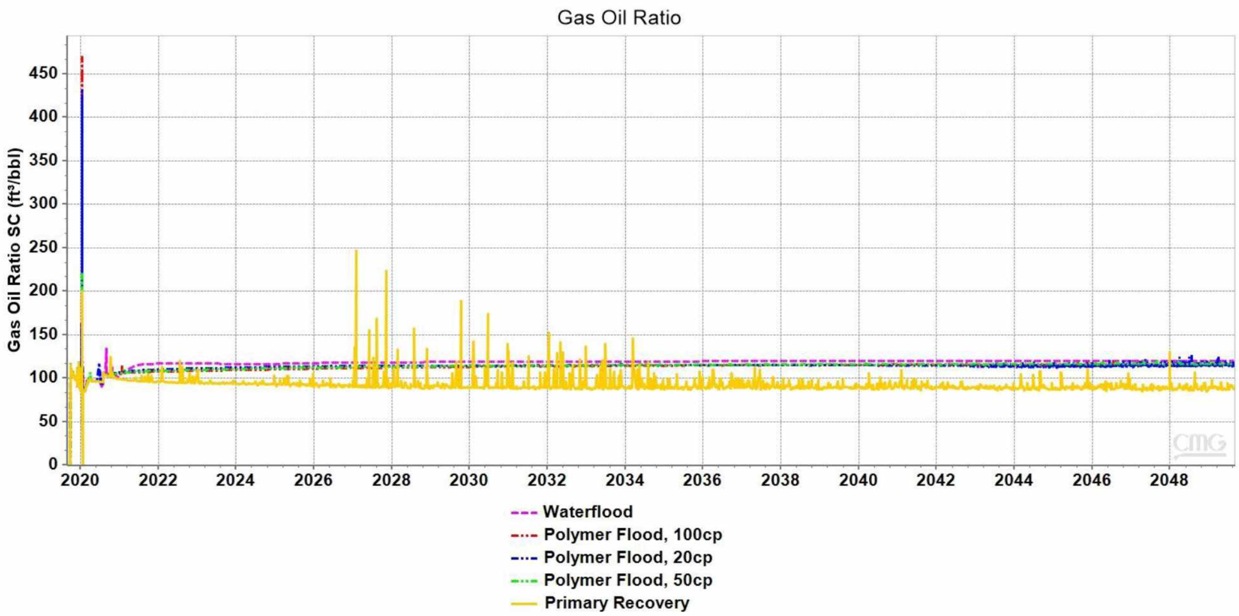

Figure 24: Prediction of Gas-Oil Ratio

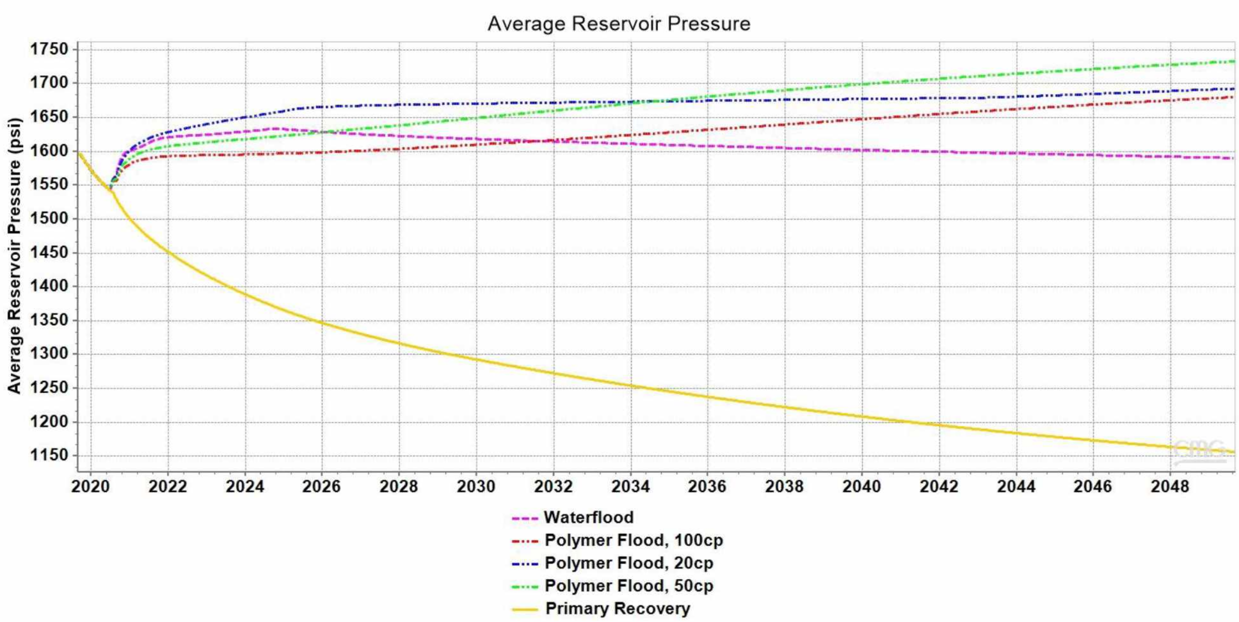

Figure 25: Prediction of Average Reservoir Pressure

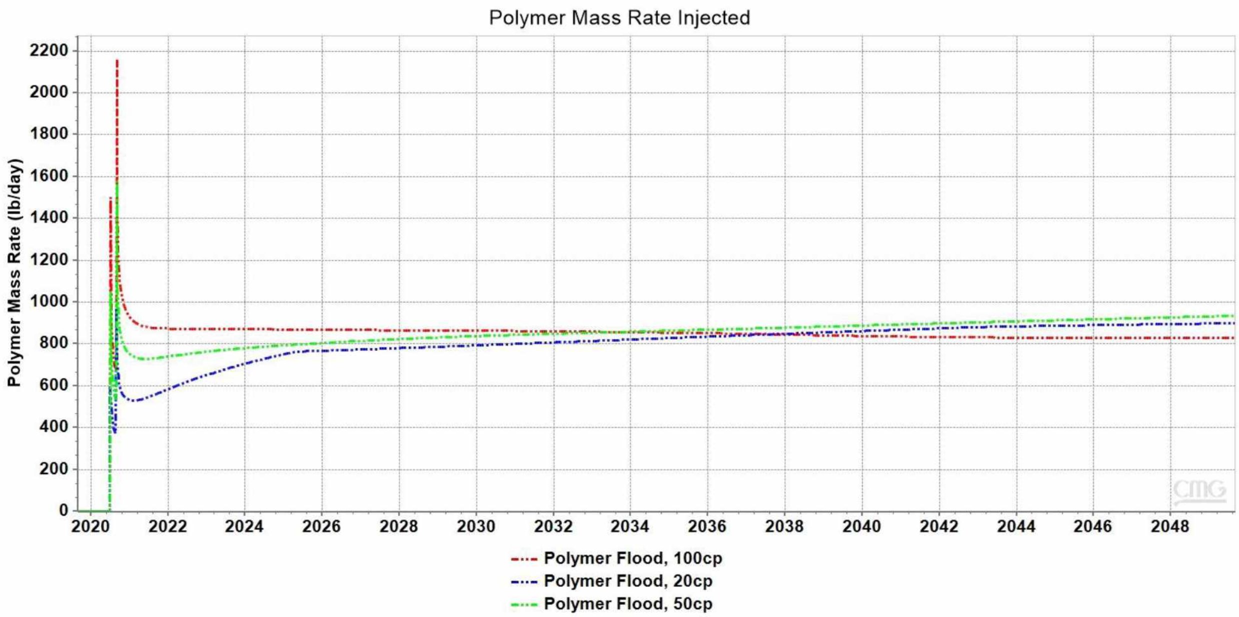

Figure 26: Prediction of Polymer Mass Rate Injected

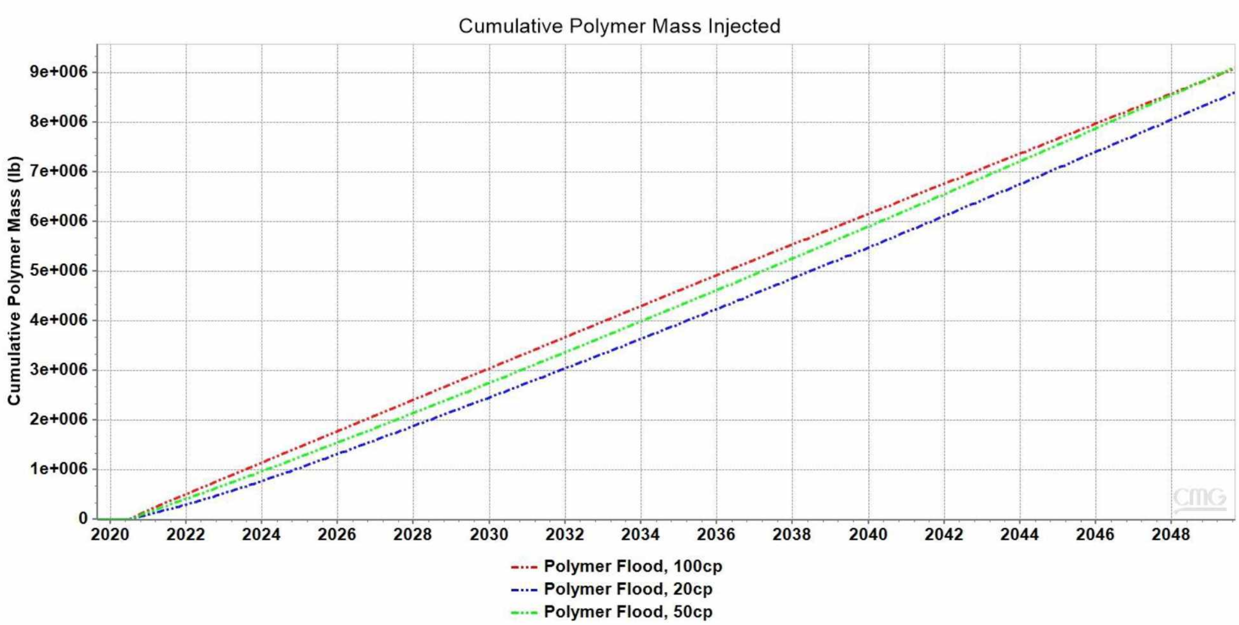

Figure 27: Prediction of Cumulative Polymer Mass Injected

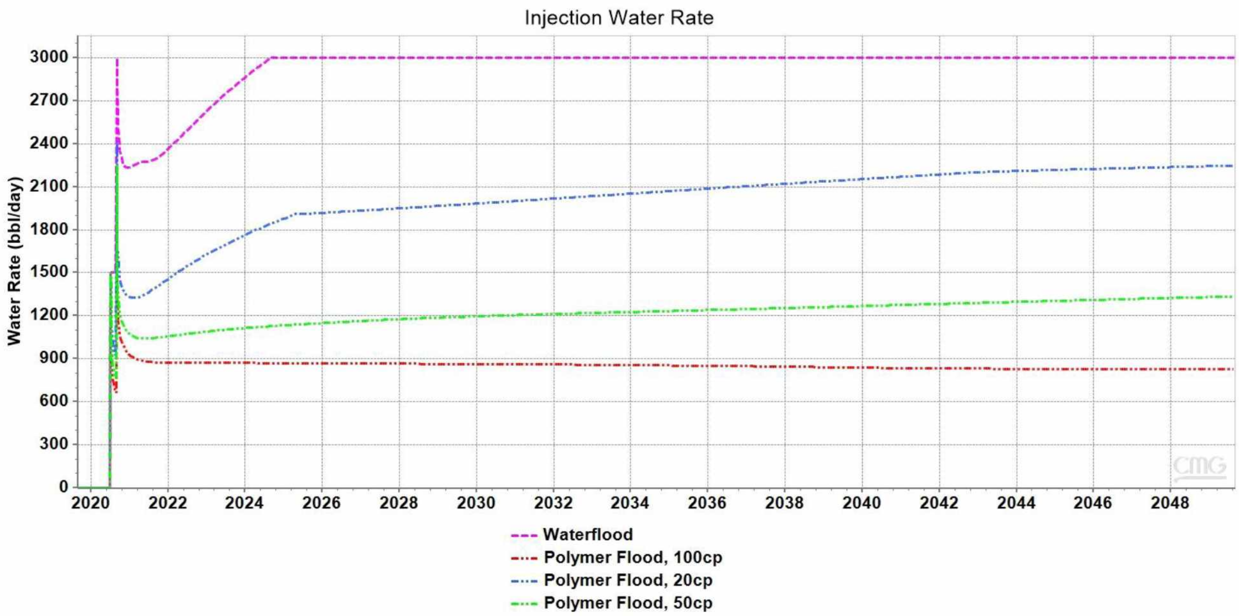

Figure 28: Prediction of Injection Water Rate

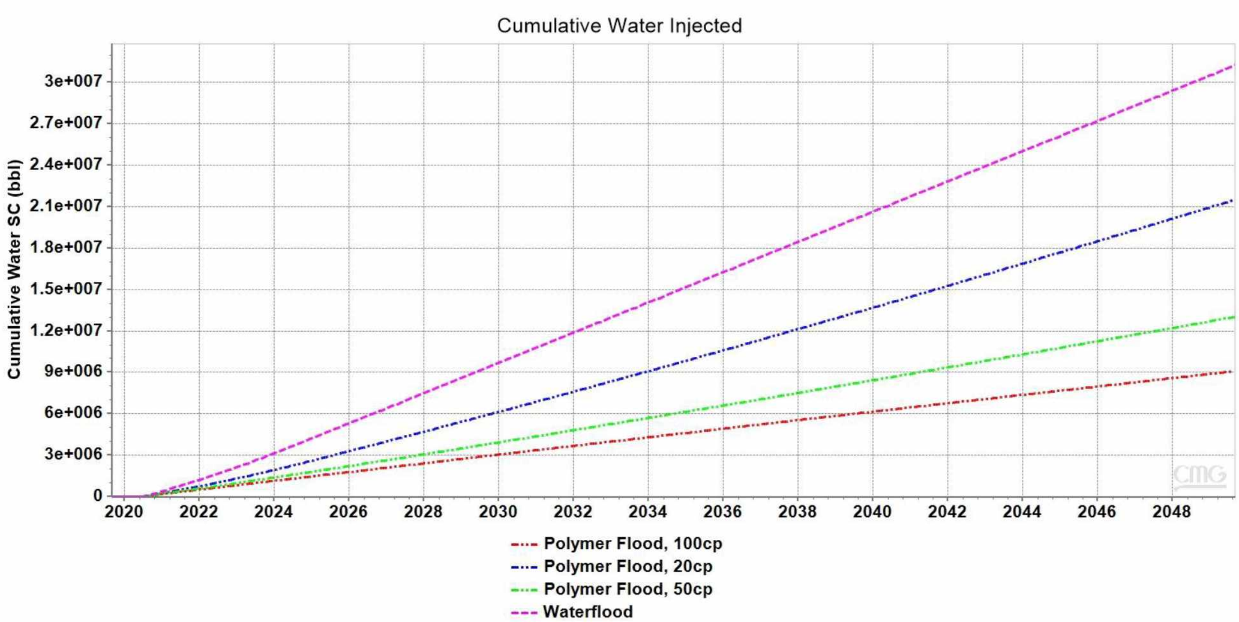

Figure 29: Prediction of Cumulative Water Injected

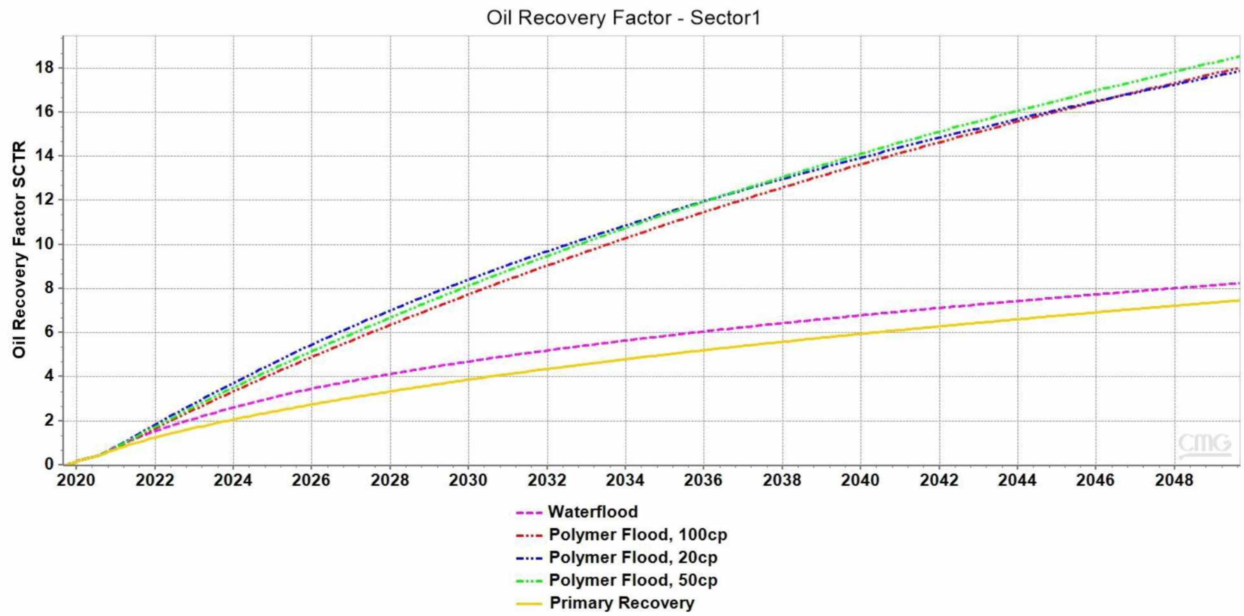

Figure 30: Prediction of Oil Recovery Factor in Sector1

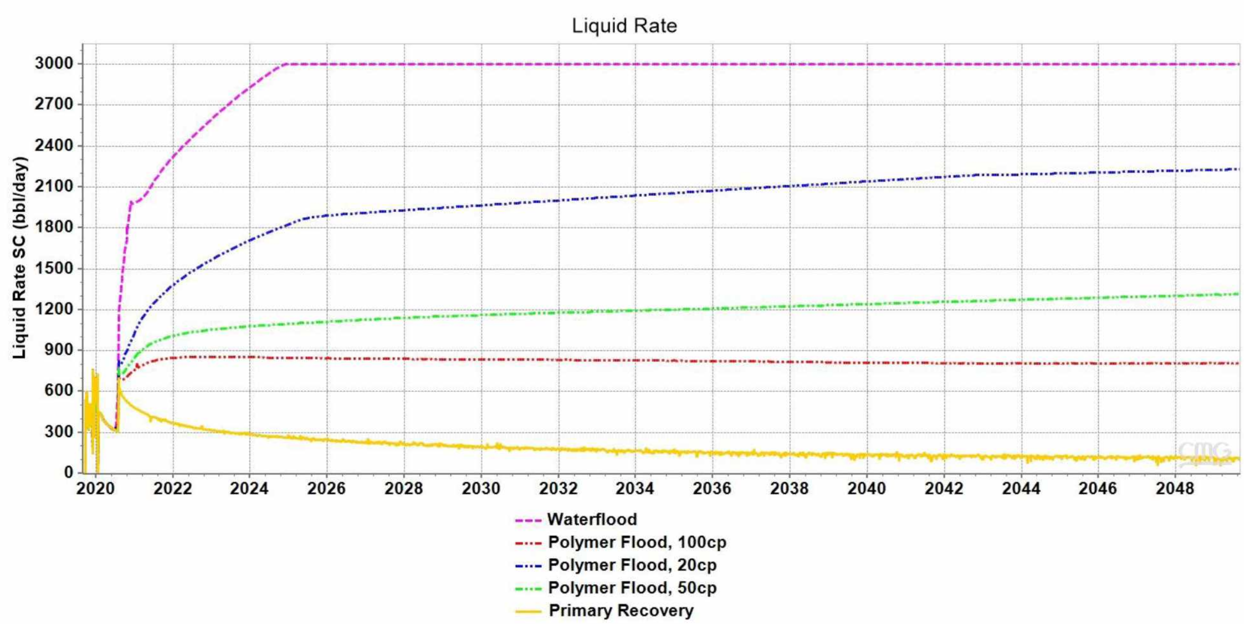

Figure 31: Prediction of Produced Liquids Rate

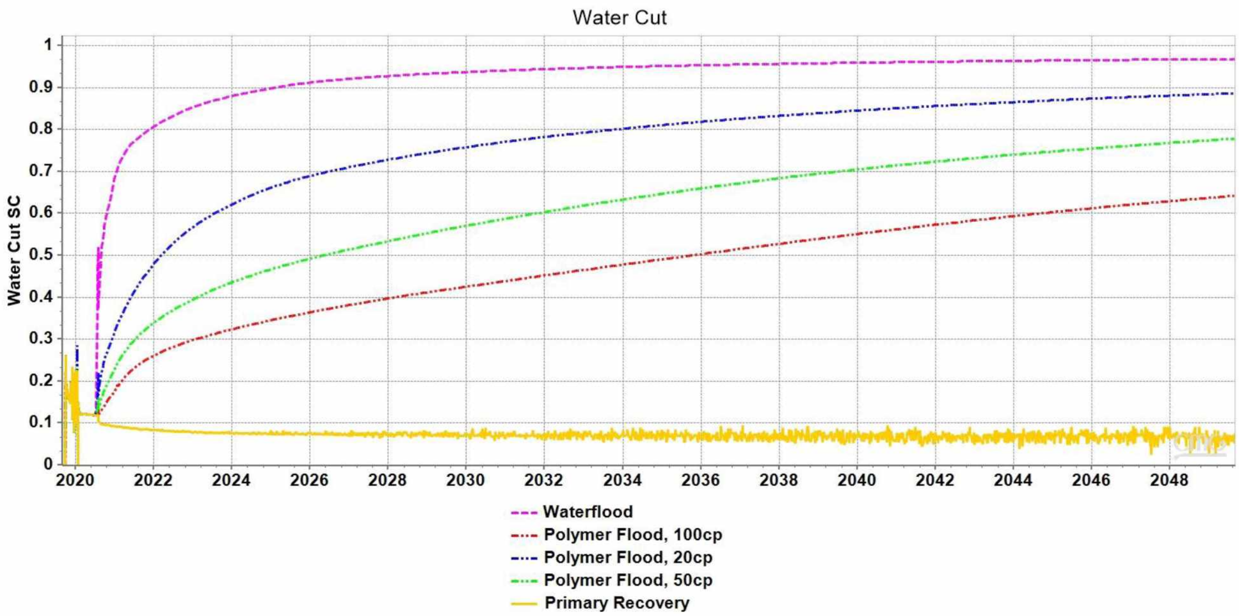

Figure 32: Prediction of Water Cut

6.2 Prediction General Discussion

The results are discussed below. Values for cumulative figures are stated for the end of the prediction. Values for rate figures are stated for the approximate rate at the end of the prediction.

- Figure 22 shows the Prediction of Oil Rate.
    - Primary Recovery: 100 bbl/day
    - Waterflood: 100 bbl/day
    - Polymer Flood: 300, 300, 250 bbl/day for 100cp, 50cp, 20cp respectively.
    - In early simulation after all wells in the respective simulations are online, the oil rate for all cases is around 600-700 bbl/day. Primary recovery quickly drops off due to a lack of pressure support, followed by waterflood. In early time, the 20cp polymer case results in the highest oil rate, followed by the 50cp case and then the 100cp case - likely because of the 20cp polymer case injecting more water and providing a less effective sweep displacement than the 50cp and 100cp case, leading to the 20cp case pushing more liquids to the production wells in early time. After 30 years in late time, the 100cp and 50cp show very similar oil rates around 300 bbl/day, followed by the 20cp case at around 250 bbl/day. In mid-late time starting around 2034, primary recovery and waterflood show very similar oil production rates at around 160 bbl/day – providing strong evidence that waterflood is not effective, as expected in this heavy oil application. In late prediction late time, both primary recovery and waterflood cases have oil rates around 100 bbl/day. The primary recovery oil rate varies the most (prediction line is not steady) when compared to other predicted rates because the corresponding gas-oil ratio varies slightly without pressure support from injectors. No pressure support from injectors leads to more gas break-out in the production well's

near-wellbore regions due to lower pressure in the simulator grid blocks in those areas.

- Figure 23 shows the Prediction of Cumulative Oil Produced.
  - Primary Recovery: 1.951 MMbbl
  - Waterflood: 2.153 MMbbl
  - Polymer Flood: 4.835, 4.701, 4.661 MMbbl for 100cp, 50cp, 20cp respectively.
  - Polymer cases showed the most productivity by a wide margin, followed by waterflood, closely followed by primary recovery. There are no significant differences between polymer flood cumulative oil produced predictions. The significant differences between the polymer flooding cases will be further explored.
- Figure 24 shows the Prediction of Gas-Oil Ratio.
  - Primary Recovery: 95 ft^3/bbl
  - Waterflood: 120 ft^3/bbl
  - Polymer Flood: 120 ft^3/bbl for each 100cp, 50cp, 20cp cases.
  - The recovery method did not significantly affect the Gas-Oil Ratio. This is likely because GOR is a function of near-wellbore region oil breakdown, not due to the displacement mechanism/recovery method. In all simulations, GOR stayed near-constant in the vicinity of 100 ft^3/bbl, with some variation in mid and late time. The recovery method did not significantly affect the Gas-Oil Ratio. This is likely because GOR is a function of near-wellbore region oil breakdown, not due to the displacement mechanism/recovery method.
- Figure 25 shows the Prediction of Average Reservoir Pressure.
  - Primary Recovery: 1150 psi

- Waterflood: 1590 psi
- Polymer Flood: 1680, 1730, 1700 psi for 100cp, 50cp, 20cp respectively.
- Injection contributes to significant reservoir pressure support. Polymer injection tends to yield more pressure support than waterflood, due to better sweep efficiency and less fluid breakthrough to production wells that would tend to lower the average reservoir pressure. After 30 years, average reservoir pressures for the polymer cases did not decline and were in the order of approximately 1,700 psi, with the waterflood case reservoir pressure at approximately 1,600 psi. In general, in all injection cases, the reservoir pressure is maintained and voidage is being replaced by injection fluids.

- Figure 26 shows the Prediction of Polymer Mass Rate Injected.
    - Polymer Flood: Approximately 875 lb/day for each 100cp, 50cp, and 20cp cases.
    - Polymer mass rate injected did not vary significantly between the three polymer cases. It was a surprise to see the absence of the 100cp polymer flood using a higher rate of polymer compared to the 20cp polymer flood. Later discussion will yield the differences between these cases. In early time, the higher target viscosity polymer flood (100cp) used a higher polymer mass rate, likely due to the relative ease of higher viscosity solution injection in that time frame as compared to others.
- Figure 27 shows the Prediction of Cumulative Polymer Mass Injected.
    - Polymer Flood: 9.084, 9.118, 8.603 million lbs for 100cp, 50cp, 20cp respectively.
    - No significant differences between the three polymer cases. Like Figure 26, it was a surprise to see the absence of the 100cp polymer flood using a higher amount of polymer compared to the 20cp polymer flood. Later discussion will yield the differences between these cases.

- Figure 28 shows the Prediction of Injection Water Rate.
  - Waterflood: 3000 bbl/day
  - Polymer Flood: 830, 1330, 2250 bbl/day for 100cp, 50cp, 20cp respectively.
  - This figure starts to show some of the differences between the three polymer cases. The polymer flood was not able to inject the full volume of 3000 bbl/day at all polymer viscosities. At 100cp, the injection was approximately 900 bbl/day. Lower viscosities were about to inject significantly more with the 20cp polymer flood and the waterflood at around 2100 bbl/day and 3000 bbl/day, respectively. The waterflood case maxed the injection wells' capacities at 1500 bbl/day. In general, injection rates were approximately inversely proportional to the flood medium viscosity.
- Figure 29 shows the Prediction of Cumulative Water Injected.
  - Waterflood: 31.24 MMbbl
  - Polymer Flood: 9.086, 13.03, 21.51 MMbbl for 100cp, 50cp, 20cp respectively.
  - Waterflood used the most water, followed by polymer flood in order lowest viscosity to the highest. The more viscous the flooding medium, the less water was injected. For example, the polymer cases resulted in much less water injected than the waterflood case, with the 100cp case injecting the least. Injection capabilities discussed in Figure 28.
- Figure 30 shows the Prediction of the Oil Recovery Factor for Sector1. The recovery factor is the recoverable amount of oil initially in place in Sector1, expressed as a percentage.
  - Primary recovery RF: 7.464%
  - Waterflood RF: 8.247%
  - Polymer Flood RF: 18.020%, 18.533%, 17.864% for 100cp, 50cp, 20cp respectively.

- Polymer flood significantly increases the recovery factor, as expected because the recovery factor depends on the displacement mechanism. There is no significant difference between the oil Recovery Factors for the three different polymer cases. This was a surprise, as the high viscous polymer floods were expected to sweep more oil. The polymer flood incremental recovery factor above waterflood was approximately 10%.

- Figure 31 shows the Prediction of the Produced Liquids Rate.
  - Primary Recovery: 100 bbl/day
  - Waterflood: 3000 bbl/day
  - Polymer Flood: 810, 1320, 2230 bbl/day for 100cp, 50cp, 20cp respectively.
  - Waterflood leads to liquid rates of 3000 bbl/day (the producing wells' max capacities) to be seen starting in 2025. 3000 bbl/day comes from the 1500 bbl/day constraint placed on both production wells. After waterflood, polymer flooding created the next greatest liquid rates, in the order from most liquids to least liquids being 20 cp case, 50cp case, then 100cp case. Primary recovery resulted in the lowest liquid rate. The produced liquid rates mirror the water injection rate as shown in Figure 27 and discussed later. Generally, produced liquids rate matched injection rates for each case.
- Figure 32 shows the Prediction of Water Cut.
  - Primary Recovery: 6.0%
  - Waterflood: 96.8%
  - Polymer Flood: 64.2%, 77.8%, 88.6% for 100cp, 50cp, 20cp respectively.
  - In general, results mirror Figure 31. As expected in heavy oil, water breakthrough is early and the water cut is high in the waterflood case. In the waterflood case, the

water cut approached 95% by 2025. Polymer flooding shows more ideal water cuts with the 100cp case simulating approximately 65% water cut after 30 years, compared to water cut approaching 90% in the 20cp case. In general, water breakthrough was common and more volume injected lead to greater water cuts.

6.3 Primary Recovery Discussion

The primary recovery prediction could be high due to the relatively high critical gas saturation used. However, this could be a reality if foamy oil develops. Foamy oil is an oil-continuous foam that contains dispersed gas bubbles produced at the wellhead from heavy oil reservoirs under solution gas drive. An extensive study of foamy oil was not conducted in this paper. Extensive primary recovery is not the objective of developing this area and discussion necessary is brief.

6.4 Waterflood Discussion

Waterflood recovery in heavy oil reservoirs is often inefficient due to early water breakthrough and high water cut as discussed previously and in Chapter 2 Literature Review. This Ugnu heavy oil reservoir is no different, and the incremental waterflood recovery over primary recovery is minimal. Water and oil are immiscible fluids, meaning they do not mix and the oil and water cannot displace the other within an oil reservoir. Also, waterflood results in a very high water cut and a produced liquids rate, with no significant oil recovery. Waterflood provides no significant gain. Much of the waterflood and polymer flood observations and can be explained by background on the topics included in Chapter 2 Literature Review, including sweep efficiency, viscous fingering, and mobility ratio. The low water viscosity and high heterogeneity in the reservoir cause these issues. For most of the prediction, the waterflood case was able to inject the full 3000 bbl/day rate, 1500 bbl/day from each injector well, which we will contrast to polymer flood injection rates in the next section.

6.5 Polymer Flood

All three polymer cases lead to significant incremental recovery over both primary recovery and waterflood. Increased sweep efficiencies were apparent. There is no significant difference between the oil recovery factors for the three different polymer cases. All polymer cases injected roughly the same amount of polymer, with the main difference being the capability to inject higher viscosity polymer. The 100cp case was able to inject significantly lower solution rates than the 50cp and the 20cp polymer flood cases. Reservoir pressure was maintained, and voidage was predicted to be replaced where it can be. All three polymer cases resulted in a more efficient sweep that waterflood with oil recovery factors at approximately 18%. The 100cp polymer flood case resulted in less water breakthrough and lower water cut mostly due to lower volumes injected, with a water cut of approximately 65% at the end of the prediction timeframe. Increasing water cut leads to expensive fluid production from the reservoir due to the need for more surface facilities such as separators. Visual examination of the reservoir model through a range of simulation dates confirmed the expected benefits of polymer flooding, such as a more efficient sweep/displacement visualization than waterflood.

Polymer utilization can be defined as polymer mass in pounds injected per barrel of incremental oil over waterflood and is presented in Table 6. Generally, a lower utilization value (closer to zero) is better but other factors can also be important. All polymer cases resulted in a polymer utilization of around 3.5 lb/bbl. In this case, the finding that the full polymer solution volume was not able to be injected at all viscosities is significant and raised questions warranting little analysis of polymer utilization for now. Other apparent concerns from examining the table are the lack of difference between the polymer cases in oil recovery and polymer mass used, as well as the large difference between water injected. The following table should be examined in comparison with the updated study discussed in Chapter 6.6. The target concentration was able to be achieved, apparent by dividing cumulative polymer mass injected by cumulative water injected and examining the polymer flood summary in Table 5.

Table 6: Polymer Utilization (Polymer Injected Per Bbl of Incremental Oil over Waterflood

Polymer Flood - Constraint of maximum 1500 bbl/day per injector (3000 bbl/day total)							
Polymer Study	Polymer Flood Cumulative Oil Production	Waterflood Cumulative Oil Production	Incremental Oil Production over Waterflood	Cumulative Polymer Mass Injected	Polymer Utilization	Recovery Factor in Sector1	Cumulative Water Injected
	bbl	*bbl*	*bbl*	*lb*	*lb/bbl*	*%*	*bbl*
100cp 1.0lb/bbl 2,855_ppm	4,701,000	2,153,000	2,548,000	9,084,000	3.565	18.0%	9,086,000
50cp 0.7lb/bbl 1,998_ppm	4,835,000		2,682,000	9,118,000	3.400	18.5%	13,030,000
20cp 0.4lb/bbl 1,142_ppm	4,661,000		2,508,000	8,603,000	3.430	17.9%	21,510,000

Due to the lack of expected results and differences between the three polymer flood cases, it was concluded further study was necessary. The prior study was unable to show a total injection rate of above 1000 bbl/day for higher viscosity 100cp polymer case. This resulted in slightly unexpected results, with all three cases showing nearly the same levels of polymer mass injected. The 100cp should use more polymer mass than the 50cp case, which should use more polymer mass than the 20cp case. Also, a difference in recovery factor between the three cases was expected and not seen in the original flood studies above – the higher viscosity polymers should improve sweep efficiency and generally help produce more oil. Therefore, a revised polymer flood was conducted with the main revision being lower flood injected rates, as described in section 6.6.

6.6 Revised Polymer Flood – Results and Discussion

Re-simulating the three polymer cases with a maximum injection rate of 500 bbl/day for injector wells (1000 bbl/day for both wells combined) resulted in Figures 33-43. The 1000 bbl/day injector rate came from the maximum water rate seen on the original 100cp polymer flood study at approximately ~900 bbl per day. 100 bbl/day difference was granted as a safety factor and considering different reservoir conditions in the revised flood studies. The waterflood case was also updated, with a waterflood injector rate matching the polymer flood cases. The updated waterflood case will assist in updated polymer utilization calculations. Discussion is available in this section after the presentation of the figures below, and in general, the results were expected and produced the desired findings of the study. Values for cumulative figures are stated for the end of the prediction. Values for rate figures are stated for the approximate rate at the end of the prediction. Primary recovery values are not stated, as the prediction was not revised. As to not repeat commentary from the prior prediction results and discussion section, the discussion is centered around the waterflood and polymer flood changes seen in the revised prediction and that was expected in the prior prediction study that was not seen in that case.

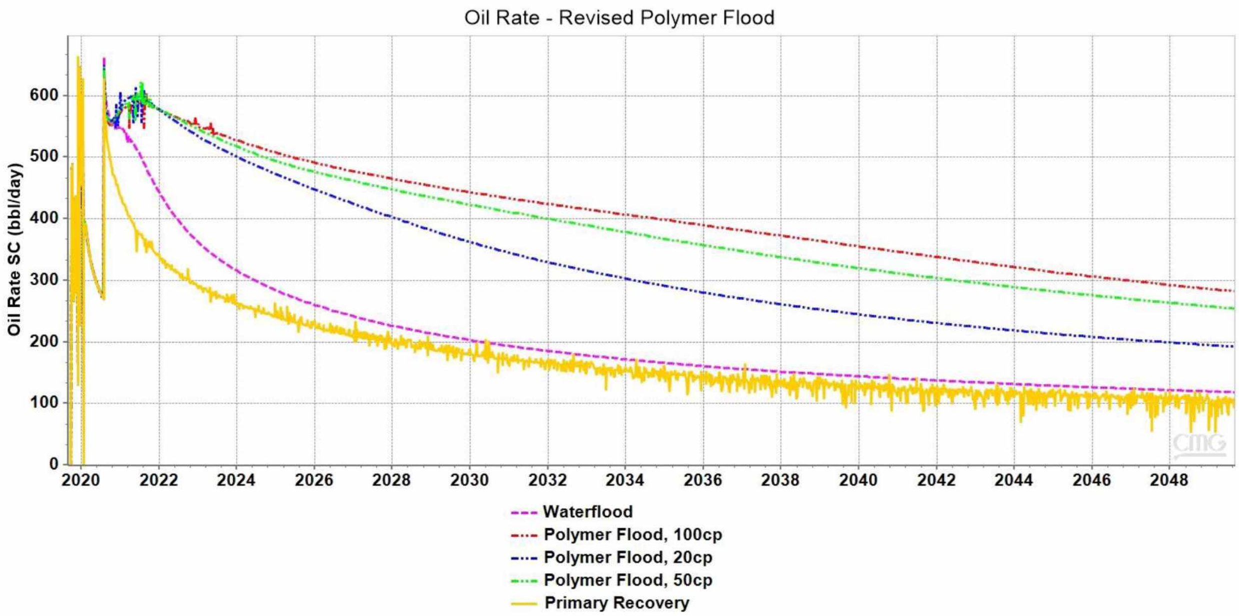

Figure 33: Revised Polymer Flood - Prediction of Oil Rate

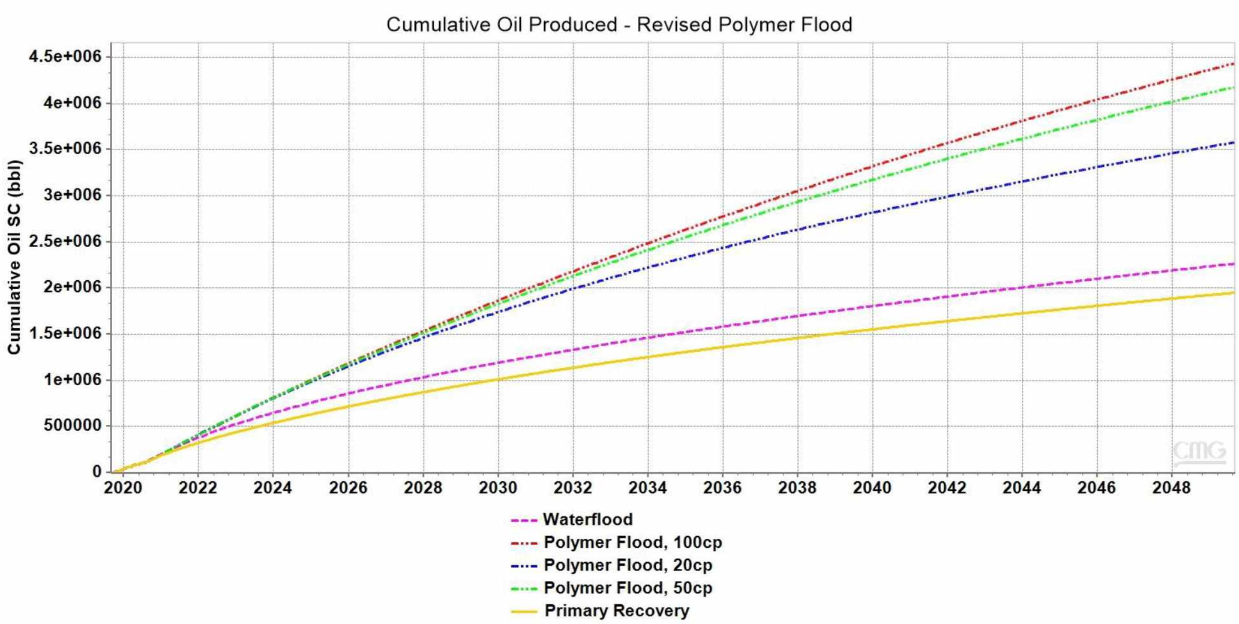

Figure 34: Revised Polymer Flood - Prediction of Cumulative Oil Produced

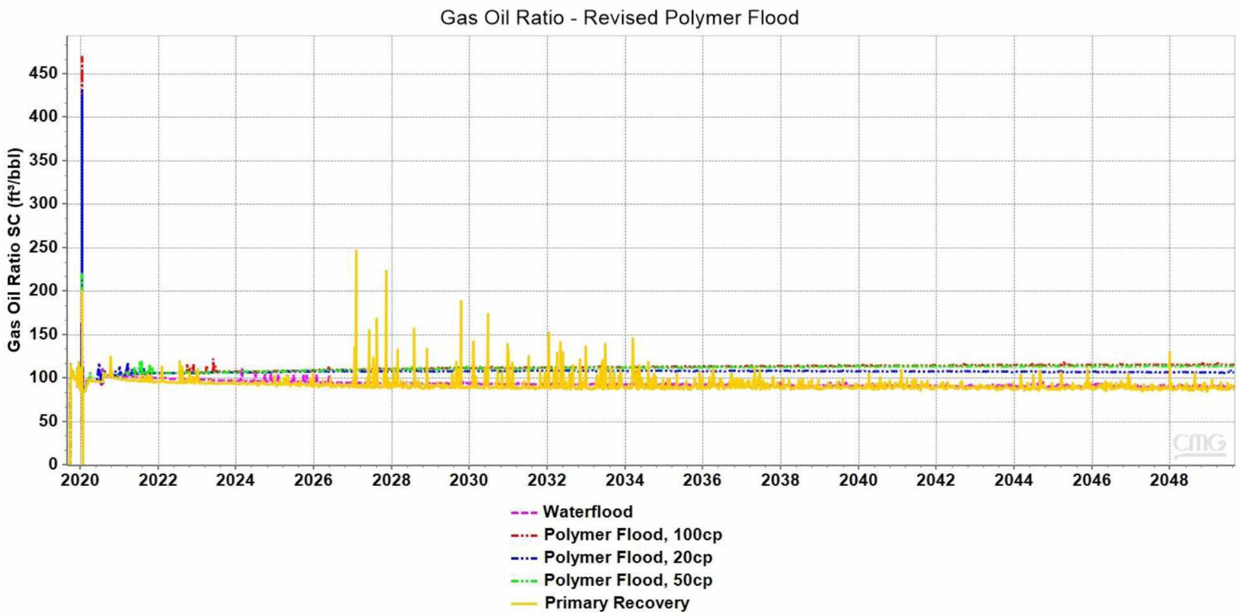

Figure 35: Revised Polymer Flood - Prediction of Gas-Oil Ratio

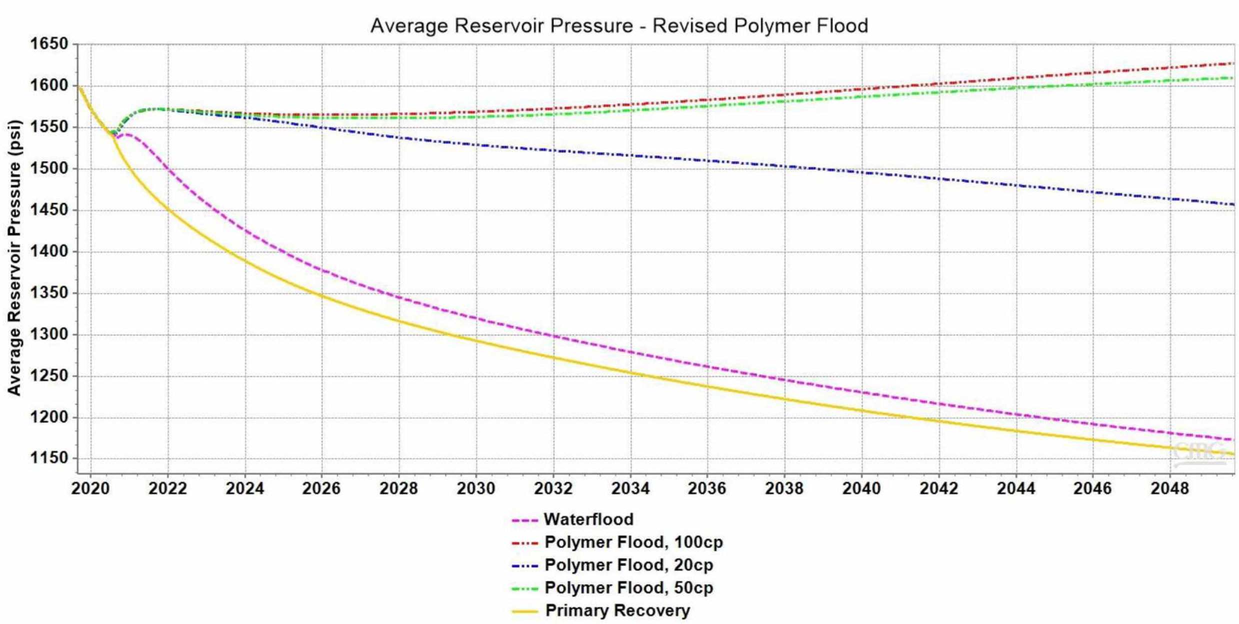

Figure 36: Revised Polymer Flood - Prediction of Average Reservoir Pressure

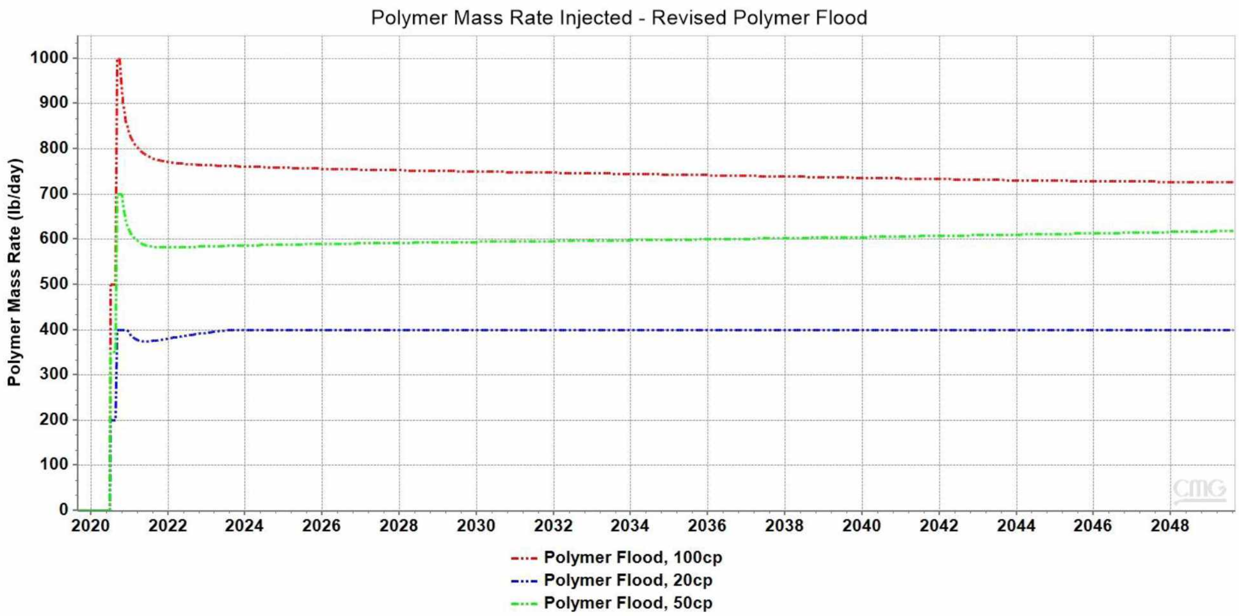

Figure 37: Revised Polymer Flood - Prediction of Polymer Mass Rate Injected

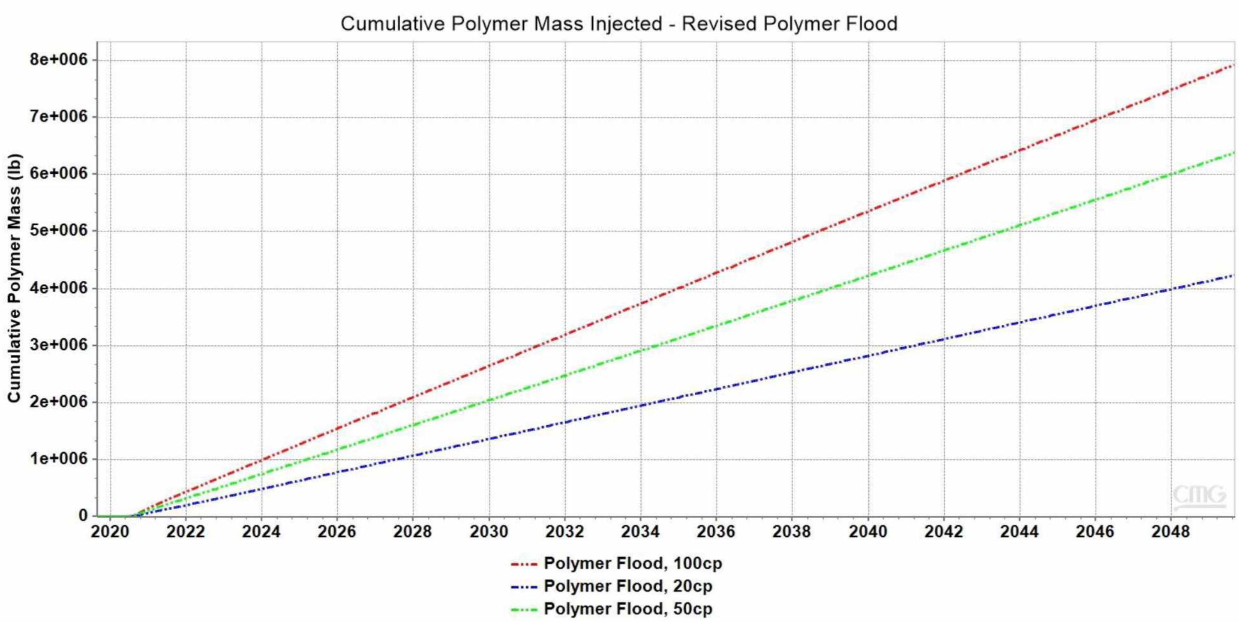

Figure 38: Revised Polymer Flood - Prediction of Cumulative Polymer Mass Injected

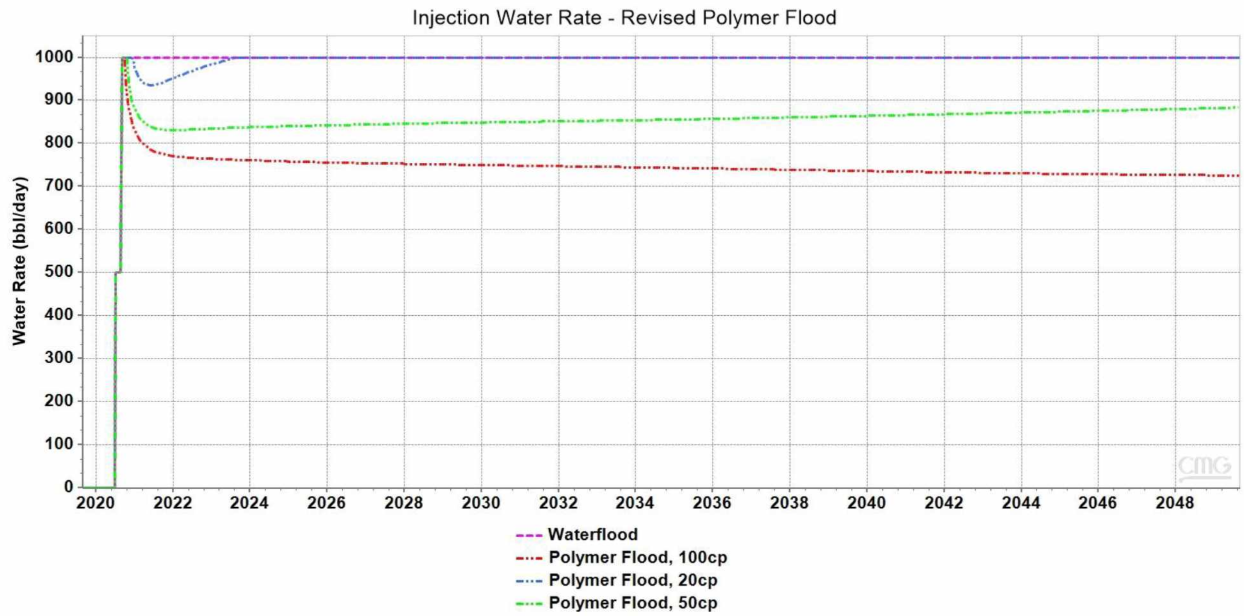

Figure 39: Revised Polymer Flood - Prediction of Injection Water Rate

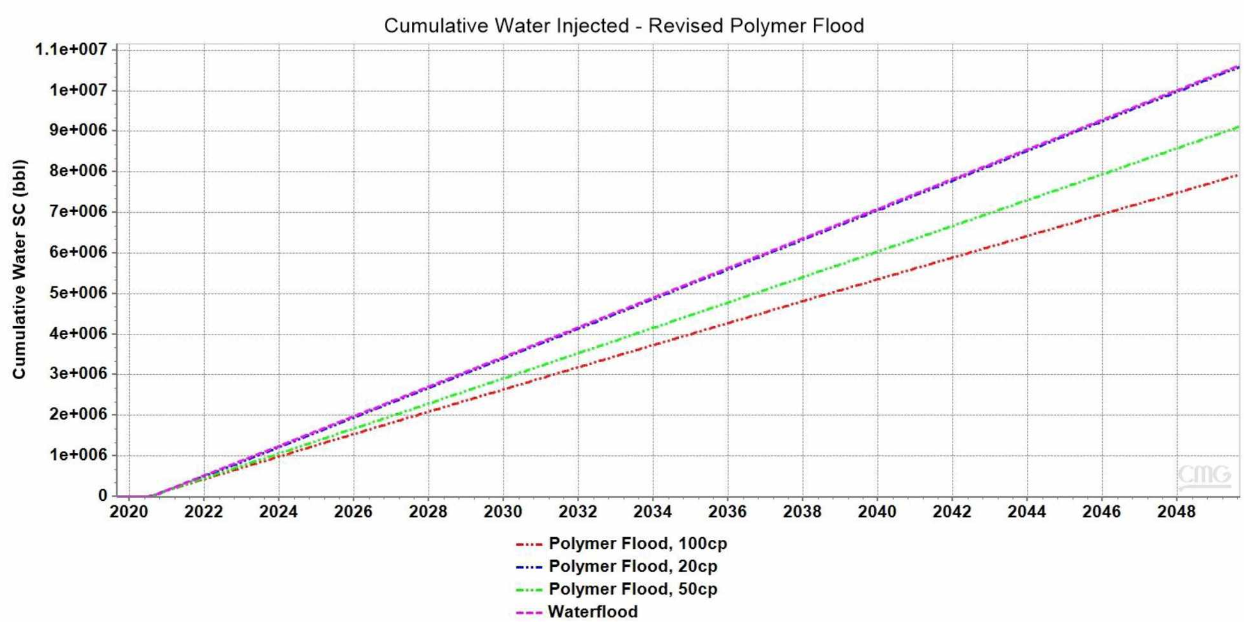

Figure 40: Revised Polymer Flood - Prediction of Cumulative Water Injected

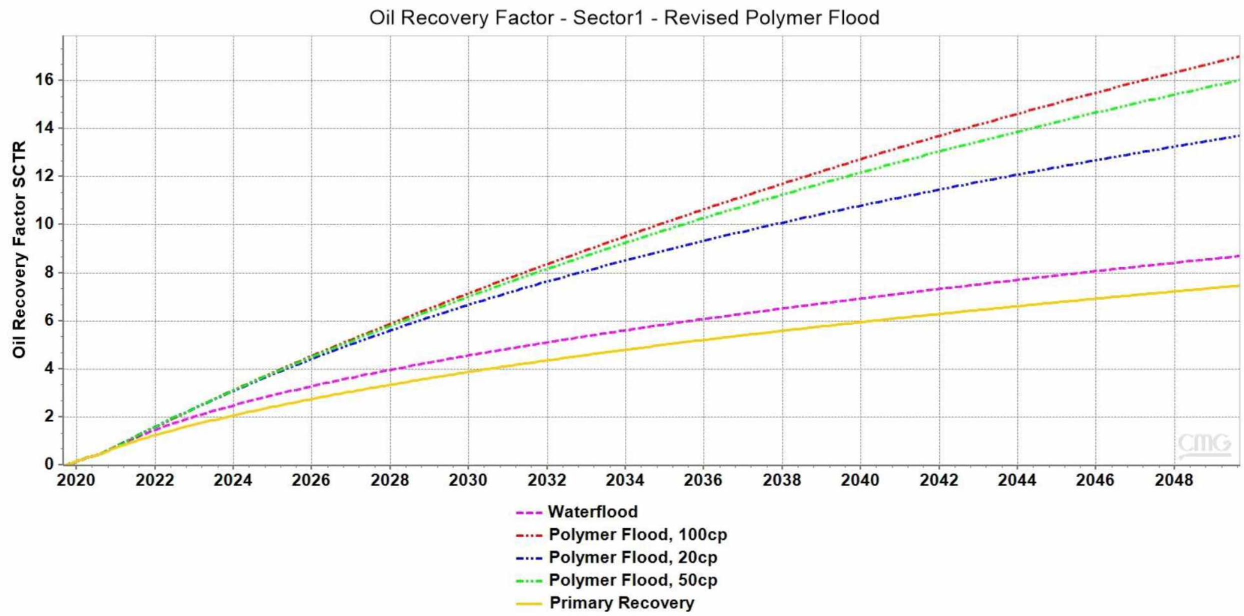

Figure 41: Revised Polymer Flood - Prediction of Oil Recovery Factor in Sector1

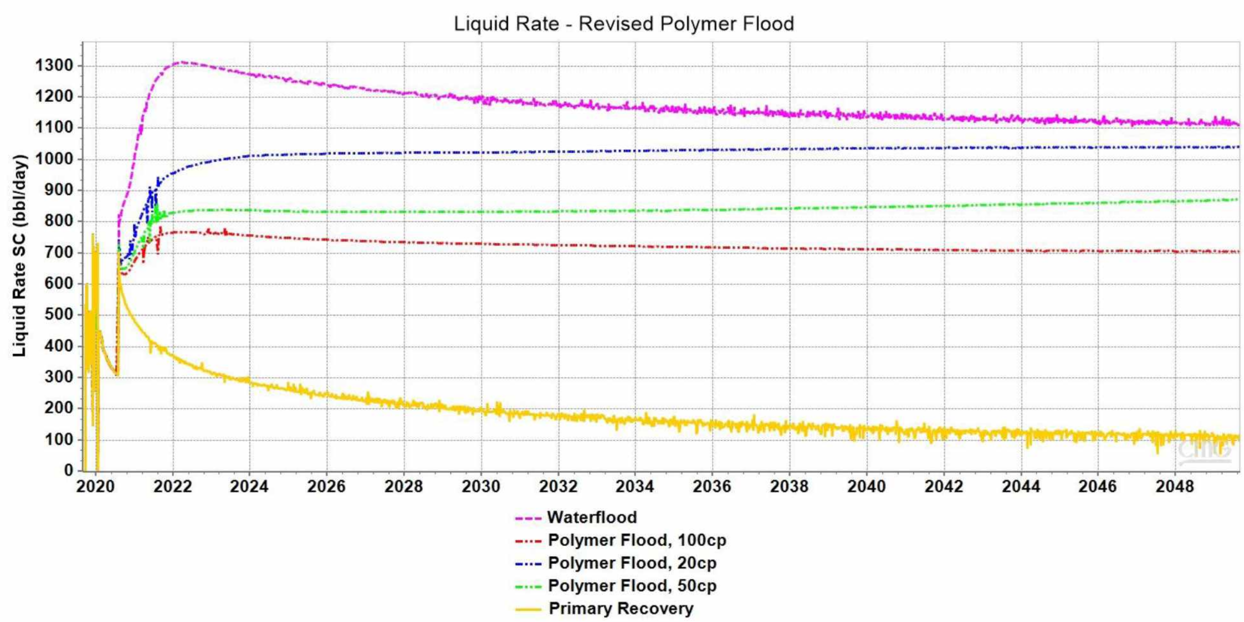

Figure 42: Revised Polymer Flood - Prediction of Produced Liquids Rate

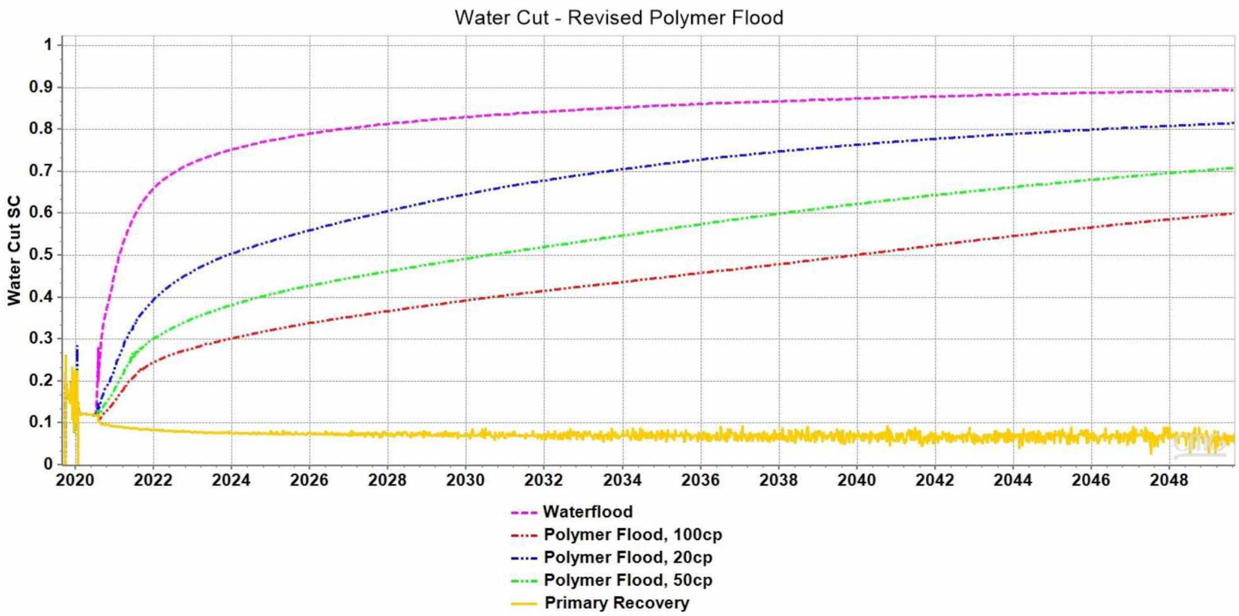

Figure 43: Revised Polymer Flood - Prediction of Water Cut

- Figure 33 shows the Prediction of Oil Rate for the revised polymer flood.
  - Waterflood: ~120 bbl/day
  - Polymer Flood: 280, 255, 190 bbl/day for 100cp, 50cp, 20cp respectively.
  - Revised polymer flood lead to slightly lower oil rates at the end of the prediction due to the lower injection rates, but oil rates were varied between the three polymer cases, which is an expected result.
- Figure 34 shows the Prediction of Cumulative Oil Produced for the revised polymer flood.
  - Waterflood: 2.266 MMbbl
  - Polymer Flood: 4.439, 4.182, 3.581 MMbbl for 100cp, 50cp, 20cp respectively.
  - Polymer cases again showed high productivity over waterflood. Cumulative production was less than prior study, but figures varied between the three polymer cases, leading to the capability for more in-depth analysis.

- Figure 35 shows the Prediction of Gas-Oil Ratio for the revised polymer flood.
    - Waterflood: 100 ft^3/bbl
    - Polymer Flood: 100 ft^3/bbl for each 100cp, 50cp, 20cp cases.
- Figure 36 shows the Prediction of Average Reservoir Pressure for the revised polymer flood.
    - Waterflood: 1175 psi
    - Polymer Flood: 1630, 1610, 1450 psi for 100cp, 50cp, 20cp respectively.
    - Injection lead to reservoir pressure support, but less than the prior study. 20cp polymer case showed pressure decline, a sign of voidage not being replaced. This is likely due to the limited injection rate, and more fluids could be injected in the 20cp case as necessary if 1000 bbl/day injection limitations were removed.
- Figure 37 shows the Prediction of Polymer Mass Rate Injected for the revised polymer flood.
    - Polymer Flood: 725, 620, 400 lb/day for 100cp, 50cp, 20cp respectively.
    - Injected rates match target concentrations (1.0, 0.7, 0.4 lb/bbl) and the higher viscosity polymer study show more polymer being used than the lower viscosity polymer studies.
- Figure 38 shows the Prediction of Cumulative Polymer Mass Injected for the revised polymer flood.
    - Polymer Flood: 7.934, 6.386, 4.232 million lbs for 100cp, 50cp, 20cp respectively.
    - Similar findings as Figure 37 on predicted polymer mass rate
- Figure 39 shows the Prediction of Injection Water Rate for the revised polymer flood.
    - Waterflood: 1000 bbl/day
    - Polymer Flood: 725, 880, 1000 bbl/day for 100cp, 50cp, 20cp respectively.

    - Waterflood and 20cp polymer cases were able to inject the full target amount of 1000 bbl/day. The more viscous polymers were able to inject less, especially the 100cp case.
- Figure 40 shows the Prediction of Cumulative Water Injected for the revised polymer flood.
    - Waterflood: 10.62 MMbbl
    - Polymer Flood: 7.934, 9.123, 10.62 MMbbl for 100cp, 50cp, 20cp respectively.
    - Similar findings as Figure 39 on the predicted injection water rate.
- Figure 41 shows the Prediction of the Oil Recovery Factor for Sector1 for the revised polymer flood.
    - Waterflood RF: 8.7 %
    - Polymer Flood RF: 17.0%, 16.0%, 13.7% for 100cp, 50cp, 20cp respectively.
    - The maximum incremental recovery over waterflood was from the 100cp polymer case, at approximately 8.3%. Another significant finding is the differences in the recovery factor between the three cases. As expected, the most viscous polymer at 100cp sweeps more efficiently and leads to a higher recovery factor.
- Figure 42 shows the Prediction of the Produced Liquids Rate for the revised polymer flood.
    - Waterflood: 1100 bbl/day
    - Polymer Flood: 700, 875, 1025 bbl/day for 100cp, 50cp, 20cp respectively.
    - In general, produced liquids rates match injection capabilities discussed in Figure 39 commentary. Rates are lower than that of the first study.
- Figure 43 shows the Prediction of Water Cut for the revised polymer flood.
    - Waterflood: 90.0%
    - Polymer Flood: 60.0%, 70.8%, 81.5% for 100cp, 50cp, 20cp respectively.

- In general, results mirror Figure 42. Waterflood breakthrough is still early and high in the heavy oil. Water cut in all cases is less of that in the first study.

Revised Polymer Flood utilization is depicted in Table 7, as well as other parameters previously discussed. The target concentration was again able to be achieved, apparent by dividing cumulative polymer mass injected by cumulative water injected and examining the polymer flood summary in Table 5. A key takeaway is the polymer utilization figures are lower and polymer utilization could be optimized through different sensitivity analysis and simulation runs. Benefits of the 100cp run include more oil production, less water injected, and a higher oil recovery factor. The benefits of the 20cp run include a lower polymer utilization. In general, higher polymer flood rates are ideal as more oil will be produced. There is no obvious trend in polymer utilization shown from these three straightforward predictions. Polymer utilization is approximately ~3.2 to 3.65 lb/bbl over waterflood, a reasonable prediction range from prior experience in discussions with an engineer familiar with the matter.

Table 7: Revised Polymer Flood - Polymer Utilization (Polymer Injected Per Bbl of Incremental Oil over Waterflood)

Revised Polymer Flood - Constraint max. 500 bbl/day per injector (1000 bbl/day total)							
Polymer Study	Polymer Flood Cumulative Oil Production	Waterflood Cumulative Oil Production	Incremental Oil Production over Waterflood	Cumulative Polymer Mass Injected	Polymer Utilization	Recovery Factor in Sector1	Cumulative Water Injected
	bbl	*bbl*	*bbl*	*lb*	*lb/bbl*	*%*	*bbl*
100cp 1.0lb/bbl 2,855 ppm	4,439,000	2,266,000	2,173,000	7,934,000	3.651	17.0%	7,934,000
50cp 0.7lb/bbl 1,998 ppm	4,182,000		1,916,000	6,386,000	3.333	16.0%	9,123,000
20cp 0.4lb/bbl 1,142 ppm	3,581,000		1,315,000	4,232,000	3.218	13.7%	10,620,000

6.7 Comparison with the ongoing Milne Point Unit Polymer Pilot

Recommendations could be given to this project with the findings of the current MPU Polymer Flood Pilot. For example, aspects of the pilot-scale validating and recommendation for polymer flooding scheduled to occur in 2021 and 2022 could be applied to this project. Polymer retention and breakthrough concepts could be applied to this pilot. Additionally, the polymer cases could be further refined and re-simulated, including simulations attempting to find optimal injection rates, as attempted in the revised polymer flood conducted in this study after the primary findings. Other polymer studies could be done to find the optimal target viscosity and more optimal (lower) polymer utilization.

Potential problems include injectivity issues, polymer breakthrough, and inaccessible pore volume. Laboratory corefloods could also be done to find approximate polymer retention values for the Ugnu study. Both the on-going pilot and this simulation predict approximately ~8+% OOIP polymer recovery increment of waterflooding. Lessons from that pilot could be applied in future commercial production of the Ugnu reservoir and the Ugnu MB sands from this pilot project. The on-going pilot covers many specifics of polymer flooding that are not included in this report but could be included at a later time.

A comparison between the ongoing Milne Point Unit polymer pilot and this simulation study is offered in Table 8. The revised polymer simulation values are used in the Ugnu study column. Notable parameter similarities include reservoir depth, pressure, and temperature. Well and flood patterns were also similar. Notable differences also include objectives of projects. This study was focused around developing a simulation model for the Ugnu MB sand in the pilot Point Unit pad pilot area, and the related goals of evaluating productivity with waterflood and polymer flood. The on-going Milne point pilot is targeted towards the application of polymer flood specifically. Target oil also differs; the Ugnu oil is heavy oil at 500 to 10,000cp, while the Schrader Bluff oil is viscous at around 300 cP. The authors of that study are aware of this study and could make further comparisons that would benefit their work.

Table 8: Comparison of the ongoing Milne Point Polymer Pilot and this Simulation Study

Parameter(s)	**Ugnu Study (this work)**	**Milne Polymer Pilot**
Sand type	Highly Unconsolidated	Unconsolidated
Depth	3,500 - 4,000 ft	3,400 - 3,900 ft
Reservoir Pressure	~1,600 psi	~ <1,600 psi
Reservoir Temperature	68°F - 75°F	70°F
Porosity Range	24-40 %	30-35 %
Permeability Range	Gross 5 to 13,000 mD (target 1,300 to 13,000 mD)	100 to 3000 mD
Oil Viscosity (in-situ)	500 to 10,000 cp (Heavy oil)	~300 cP (Viscous oil)
OOIP in Flood Pattern	24 MMBO	22 MMBO
Sector/flood Pattern	Offset Parallel Laterals	Offset Parallel Laterals
Wellbore Lengths	~8,500 ft	~4,200-5,500 ft
Inter-well Distance	~700 ft	~1,500 ft
Well Patterns	Two Injectors, Two Producers (Horizontal Laterals)	Two Injectors, Two Producers (Horizontal Laterals)
Primary Recovery Predicted	1.951 MMbbl oil at the end of the prediction	Not in Scope
Waterflood recovery Predicted	2.266 MMbbl oil at the end of the prediction	Not in Scope
Polymer Concentration Injected	100, 50 cp, 20cp (2855, 1998, 1142 ppm respectively)	50cp (1700-1800 ppm)
Polymer Retention	30 micrograms per gram of rock (μg/g)	28 μg/g recent findings, ~200μg/g early on (lab corefloods)
Polymer Utilization range	~3.2 to 3.65 lb/bbl over waterflood	Not Provided

CHAPTER 7 CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

Based on this study, the following are the main conclusions drawn:

1. A numerical reservoir simulation model for the Ugnu MB sand in the Milne Point Unit pad pilot area has been developed. The model includes sensitivity analysis to support drilling development plans and evaluate productivity in the proposed Ugnu MB sand well pattern.
2. The waterflood pattern in the 24 MMBO OOIP Ugnu MB sand has shown sustainable production capability.
3. Predictions include primary recovery, resulting in relatively low oil recovery. Predictions also include waterflood, resulting in marginal recovery over primary recovery
4. The results show polymer flood significantly increases oil recovery, as expected because the recovery factor depends on the displacement mechanism. Questions remain and no specific polymer flood recommendations are made, however a high rate of polymer flood is generally recommended as it will yield in more oil production. Polymer utilization is presented and is approximately ~3.2 to 3.65 lb/bbl over waterflood, a reasonable prediction range from prior experience.

7.2 Recommendations

1. Extended durations of primary recovery are not recommended at this time. Further study is warranted, including other history matches and pilots. Waterflood recovery is especially not recommended, as expected with the nature of heavy oil.
2. Results are in favor of polymer flooding, assuming other favorable conditions including economics regarding polymer injection and oil price, beyond the scope of this project. Future development of polymer flood is recommended at this time and other polymer flood sensitivity analyses need to be conducted. Detailed technical and economic polymer-flood study needs to be carried out. Economics is not included in this report.
3. While a higher rate of polymer flood would result in more oil production and is generally recommended, it is imperative to perform laboratory and field-scale studies to achieve optimal polymer flooding. Optimal polymer flooding means low cost, high viscosity at low concentration of polymer, and usable in the respective rock type of the Ugnu MB sands. This numerical reservoir simulator model for the Ugnu MB sand in the Milne Point Unit pad pilot area should be built up and verified by petroleum engineers and geologists. Other simulations built particularly for EOR polymer flood could be used, such as STARS by CMG.
4. Key takeaways from the ongoing Milne Point Unit polymer flood pilot study discussed in this report need to be examined and applied to this project. That project covered polymer flood specifics in more detail than this project and is ongoing.

NOMENCLATURE

ANS	Alaska North Slope
API	American Petroleum Institute
bbl	Barrel
Bbbl	One-billion barrels
BHP	Bottomhole pressure
B_o	Oil Formation Volume Factor
BP	British Petroleum
Builder	CMG Builder software
CHOPS	Cold Heavy Oil Production with Sand
CMG	Computer Modeling Group
c_o	Compressibility Oil
cp or cP	Centipoise
EOR	Enhanced oil recovery
E_g	Expansion Factor of Gas
ft / ft^3	Foot / cubic foot
FVF	Formation Volume Factor
GOR	Gas-Oil Ratio
HPAM	Hydrolyzed Polyacrylamide (polymer)
IMEX	Implicit pressure Explicit Saturation
lb	Pound
MB	Ugnu MB sands
mD	Millidarcy
MMbbl	One-million barrels
MMBO	One-billion barrels oil
MPU	Milne Point Unit
OIP	Oil in place
OOIP	Original oil in place
Pcow	Capillary Pressure
Ppm	Part per million
psi	Pounds per Square Inch
PVT	Pressure Volume Temperature
RESCUE	Reservoir Characterization Using Epicenter
R_s	Solution Gas-Oil Ratio
SPE	Society of Petroleum Engineers
STB	Stock Tank Barrel
Sw	Saturation Water
UAF	University of Alaska Fairbanks
Ugnu	Ugnu Sands
µg	Microgram
VisG	Viscosity Gas
VisO	Viscosity Oil

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