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Polymer Flooding the Minnelusa in the Powder River Basin of Wyoming

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Enhanced Oil Recovery Institute

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Cover Photo: Minnelusa outcrop in Redbird Canyon, northeastern Wyoming.

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Executive Summary

Polymer-augmented waterflooding of the Minnelusa in Wyoming has proven to be a successful method for improving production in most cases compared to normal waterfloods. Polymer is a low-cost, low-risk option when considering a method for enhancing production of a particular field. Its primary function is to improve the mobility ratio of the injected water by increasing its viscosity, thereby improving the volumetric sweep and conformance within the reservoir.

Advantages of using polymer include: (1) low cost, (2) preventing early water breakthrough, (3) improving volumetric sweep and conformance, (4) increasing oil-water ratios, (5) mobilizing oil that would likely have been bypassed under normal waterflood conditions, (6) mitigating heterogeneous permeabilities within the reservoir, and (7) other enhanced oil recovery injection technologies can still be applied after the polymer flood.

Most, but not all, Minnelusa fields examined exhibited improved recoveries using polymer compared to fields under conventional waterfloods. Uneconomical polymer floods can be caused by a variety of factors, chief of which is the failure to properly understand the internal architecture of the reservoir prior to initiating the flood. Understanding the distribution of flow units within a field, designing an efficient well pattern that fits the geometry of the flow units, identifying the problems that a polymer needs to address, and selecting the proper polymer to address those problems are all key factors for optimizing any type of polymer-augmented flood.

Associated chemical costs for the polymer, relative to the year 2020, can be as low as about $1.20 per incremental barrel of oil recovered (Manrique and Lantz, 2011), although most fields examined in this study exhibit slightly higher costs. Nevertheless, the economics of polymer flooding suggest that the method should be seriously considered for enhanced oil recovery (EOR) applications in Minnelusa reservoirs.

Introduction

Wyoming has been an important oil-producing state since the first successful oil well was completed in 1883. Today, Wyoming is the eighth-largest crude oil-producing state in the nation and together with coal and natural gas, produces fifteen times the energy that it consumes (EIA, 2020). Many of the legacy oil fields in Wyoming are reaching the end of their economic life using only primary and secondary recovery methods, yet they still contain significant recoverable oil reserves. For just those fields still on primary recovery in the state, an additional 250 million barrels of oil could be recovered if waterfloods were initiated (Whitaker and Freye, 2018). Using various EOR methods, at least an additional 800 million barrels of oil could be produced in the state from existing fields (Cook, 2012).

The EOR methods selected for improving recovery in legacy fields are dependent on a variety of factors but primary among them, economics and the reservoirs being targeted. EOR methods tend to be broken down into four categories: gas, chemical, thermal, and biologic (microbial). This paper will concentrate on one aspect of chemical EOR (CEOR), polymer injection; in particular, polymer-augmented waterfloods in the Minnelusa Formation.

Why the Minnelusa is a Good Candidate for Polymer Floods

The Minnelusa Formation (Pennsylvanian-Permian) is one of the more important, conventional oil-bearing intervals in Wyoming, with over 610 million barrels of oil produced thus far from over 200 small fields. The oil-productive reservoirs are found in the upper portion of the formation (Wolfcampian) where eolian sandstones represent the preserved remnants of multiple episodes of off-shore progradation into the evaporitic carbonate environment of the northern Lusk Embayment (Figure 1). This cyclic deposition, along with lateral facies changes, cause lateral and vertical variations in reservoir quality (porosity and permeability). The Dykstra-Parsons permeability coefficients for Minnelusa reservoirs range from 0.6 to 0.9, indicating moderate to extreme permeability variations (Mack, 1978; Mack and Duvall, 1984; Hochanadel, et al., 1990; Fielding, et al., 1994). These reservoir heterogeneities tend to adversely affect primary and secondary recovery.

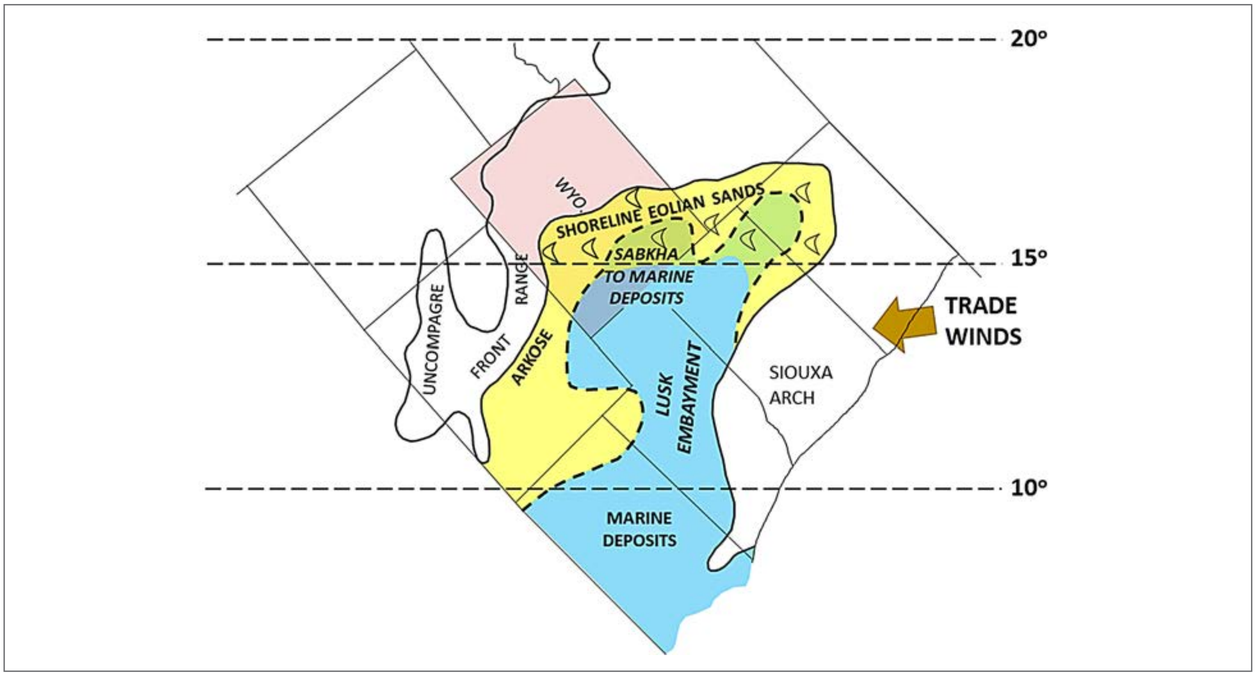

Figure 1. Early Permian (Wolfcampian) paleogeography of the Minnelusa. Minnelusa oil-bearing reservoirs in Wyoming are limited to the northern portion of the ancient Lusk Embayment where eolian sands prograded into a sabkha-shallow marine environment. (After Heckel, 1980 and Peterson, 1980).

In addition to the flow unit heterogeneities present in mixed eolian, shallow-marine environments, most Minnelusa fields exhibit low gas-oil ratios (GOR) and contain oil in the 18º - 40º API gravity range, with the vast majority of these fields falling in the lower (more viscous) end of that spectrum. Due to these characteristics, primary production in the Minnelusa tends to have a lower-than-average recovery efficiency, or recovery factor (RF), than many other conventional reservoirs in the state. Although waterflooding has proven to be a suitable method for improving the recovery efficiency compared to primary production methods, it too suffers from the aforementioned reservoir and oil characteristics within the Minnelusa. According to data at the Wyoming Oil and Gas Conservation Commission (WOGCC), slightly over half of Minnelusa fields have been subjected to waterfloods.

The relatively heavy oil and varying permeabilities within the flow units of most Minnelusa sandstone reservoirs commonly result in relatively rapid water breakthroughs during conventional waterflood operations (Figure 2). In those fields where these breakthroughs occur, the RFs of mature waterfloods have been as low as 25 percent.

These two main issues, high-permeability streaks (thief zones) and viscous fingering of the water through the Minnelusa oil, are the primary reasons polymer flooding was developed. With proper and detailed characterization of Minnelusa reservoirs, an optimal polymer flood can be designed for most fields that will improve production compared to normal waterfloods.

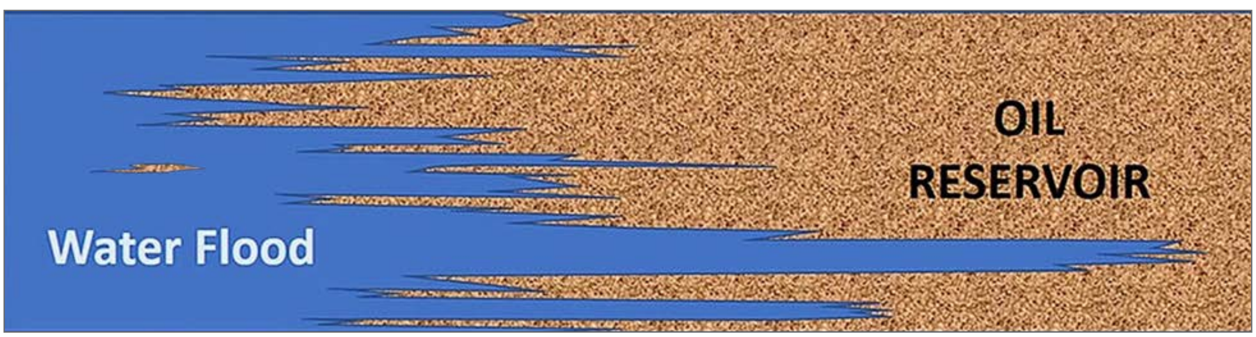

Figure 2. Diagrammatic representation of viscous fingering seen when low-viscosity water (blue) displacing higher viscosity oil (brown). Flow is from left to right.

Polymer Flooding Basics

Polymer flooding can be subdivided into (1) mobility-control floods, (2) gel treatments, (3) cationic (Cat-An) floods, and (4) colloidal-dispersion gels (CDG). Each of these flood types has strengths and weaknesses that need to be understood before selecting the one, or the combination, that best addresses the problems of a specific reservoir.

Mobility-control floods involve the addition of an anionic polymer to increase the viscosity of the injection water. This type of flood tends to require continuous injection of polymer through most of the life of the flood in sufficient volume to affect the entire flooded reservoir.

A few fields in Wyoming have utilized this type of polymer flood, such as in the Pennsylvanian/Permian Tensleep sandstone at Oregon Basin (DeHekker, et al., 1986).

Polymer-gel treatments are designed to block high-permeability thief zones and to deflect the injection stream into less permeable zones. This type of flood requires injection of a polymer and a cross-linking agent (to alter the polymer's characteristics) at intermittent times throughout the life of a flood. Normally this type of treatment is used to help seal off fractures or high-capacity thief zones, which are rarely encountered in the Minnelusa (e.g., Halverson and Simpson Ranch fields) but are common in the Tensleep (e.g., Buffalo Basin, Wertz, and Lost Soldier) (Sydansk and Moore, 1990 and 1992).

A Cat-An flood requires the injection of a cationic polymer before alternating slugs of aluminum citrate and an anionic polymer, which facilitates adsorption on the rock surface. In this type of flood, the polymer is preferentially carried into the zones with the highest permeabilities and partially clogs those zones, thus reducing their permeability and forcing the subsequent injectants to be deflected into less permeable, unswept zones. Commonly, this method is applied to injection wells that are exposed to rocks with layers containing large permeability differences, such as was the case in the Minnelusa at Semlek West, Simpson Ranch, Kuehne Ranch, and Glo North fields.

CDG floods use a modified version of the Cat-An process and are normally used in those reservoirs where the injection wells have encountered high-permeability thief zones. The theory is that the CDG will be transported along with the flood waters preferentially into the thief zones and will decrease the permeability there, thus deflecting the flood into lower permeability zones that still contain unswept oil. There is some controversy regarding the effectiveness of this method away from the injection site based on some laboratory work, but nevertheless, over 40 percent of Minnelusa polymer floods have used CDG (Lantz and North, 2014).

Before deciding which type of polymer application to use, an operator needs to have a thorough understanding of the issues within the reservoir that are affecting recovery. These issues can include: (1) variations in permeability (conformance issues) that prevent an efficient sweep, (2) trapping of oil within pore spaces by capillary effects (Muskat, 1953; Arriola, et al, 1983), (3) the relative permeability characteristics of the rock, which control the relative mobility of the oil and water when moving through the pore space (Buckley & Leverett, 1942), and (4) the mobility ratio of the water-oil system is not sufficient to thoroughly displace the viscous Minnelusa oil.

How Polymer Can Affect the Recovery Factor

The factors affecting the RF from a waterflood can be understood by considering the following equation:

$$RF = E_D \times E_V \times E_A \times E_C$$

RF is the recovery factor (volume of oil recovered over the volume of oil originally in place (OOIP), both measured at the surface). $\mathbf{E_D}$ is the microscopic displacement efficiency, which describes the percentage of pore space contacted by the injection fluid and the fraction of oil displaced from those pores. $\mathbf{E_V}$ is the vertical displacement efficiency and is dependent on the fraction of the vertical section of the reservoir contacted by the injection fluid(s). The E_V is greatly affected by heterogeneity in reservoir permeability and to a lesser extent by gravitational segregation of fluids in the reservoir. $\mathbf{E_A}$, the areal sweep efficiency, is the fraction of the total flood pattern contacted by the injection fluid(s). The E_A is affected greatly by flow unit geometry and by well spacing. $\mathbf{E_C}$ is the economic efficiency factor representing the physical and commercial constraints on a field such as efficiency and condition of facilities, reservoir energy, and net profits from operations.

Improving the RF of a reservoir depends on increasing any of the factors indicated in the above equation. EOR methods are normally focused on improving E_D and E_V, which in turn, can affect the E_A. If, however, an EOR method reduces the volume of undesired fluids (i.e., water) being produced, it can also affect E_C.

Factors affecting microscopic displacement efficiency: Factors that influence E_D include capillary effects and relative permeability characteristics of the reservoir rock, which in turn control the relative mobility of the oil and water moving through the pore spaces. The importance of pore-scale capillary effects on displacement can be quantified by the capillary number

$$Ca = \frac{v\mu}{y}$$

where v is the interstitial velocity, μ is the fluid viscosity and y is the interfacial tension (IFT) between the displaced and displacing fluids. When $Ca < 10^{-5}$, flow is dominated by capillary effects and capillary trapping is likely to occur.

Viscosity of Minnelusa oil is typically in the 7-20 cp range at reservoir conditions (Barati, 2011), which is significantly greater than the mix of low-salinity water from the Cretaceous Fox Hills Formation and the produced water from the Minnelusa, which comprise the most common injectants. The typical interstitial velocity in an oilfield displacement (distant from the wells) is approximately 10^{-5} m per second (Muggeridge, et al, 2013). It is normally not possible to apply a sufficiently large pressure gradient between wells to significantly increase the interstitial velocity or to maintain this velocity while injecting a fluid. Therefore, the most reasonable way to increase the capillary number is to reduce the IFT.

One way to reduce the IFT is by CEOR, which requires the addition of chemicals to the injected water. Depending on the process, the chemicals may change the IFT of water with oil (usually through the use of surfactants and alkalis), or, as in the case of polymers, by making the water viscosity a closer match to that of the oil it is displacing, thereby improving the mobility ratio.

Over time, different polymers can be used to mobilize oil in less and less permeable portions of the reservoir in order to more effectively recover more oil. Injection of more robust polymers would most likely occur in stages wherein each targeted flow unit within the reservoir is swept and more incremental oil is produced.

Factors affecting vertical and areal sweep efficiency: E_V is affected mostly by the differences in permeability of the various layers within the reservoir. Permeability within a reservoir is dependent on the connectivity, number, and size of pores in the rock. A mixture of rock layers with relatively high permeability and low permeability are one common form of geologic heterogeneity. Injected water will flow preferentially through higher-permeability zones while bypassing volumes of oil contained in areas with lower permeability (Figure 2).

The effect of geologic heterogeneity on oil production is exacerbated if the injected fluid has a significantly lower viscosity than the oil. This situation is common in the Minnelusa and has a great influence on E_A. This effect can be characterized by the mobility ratio, M, which compares the mobility of the displacing fluid (e. g. water) and the displaced fluid (e. g. oil)

$$M = \frac{\lambda_{water}}{\lambda_{oil}} = \frac{K_{water} / \mu_{water}}{K_{oil} / \mu_{oil}}$$

where λ is the mobility, K is permeability, and μ is viscosity. The higher the mobility ratio, the more likely it is for water to bypass oil through viscous fingering. Normally, a mobility ratio greater than 1 is considered unfavorable. During a conventional waterflood in this scenario, oil is left behind because it is trapped by capillary forces or it is bypassed. The mobility ratio will need to improve in order to better move the oil, which can be done by adding polymer to the water (Figure 3).

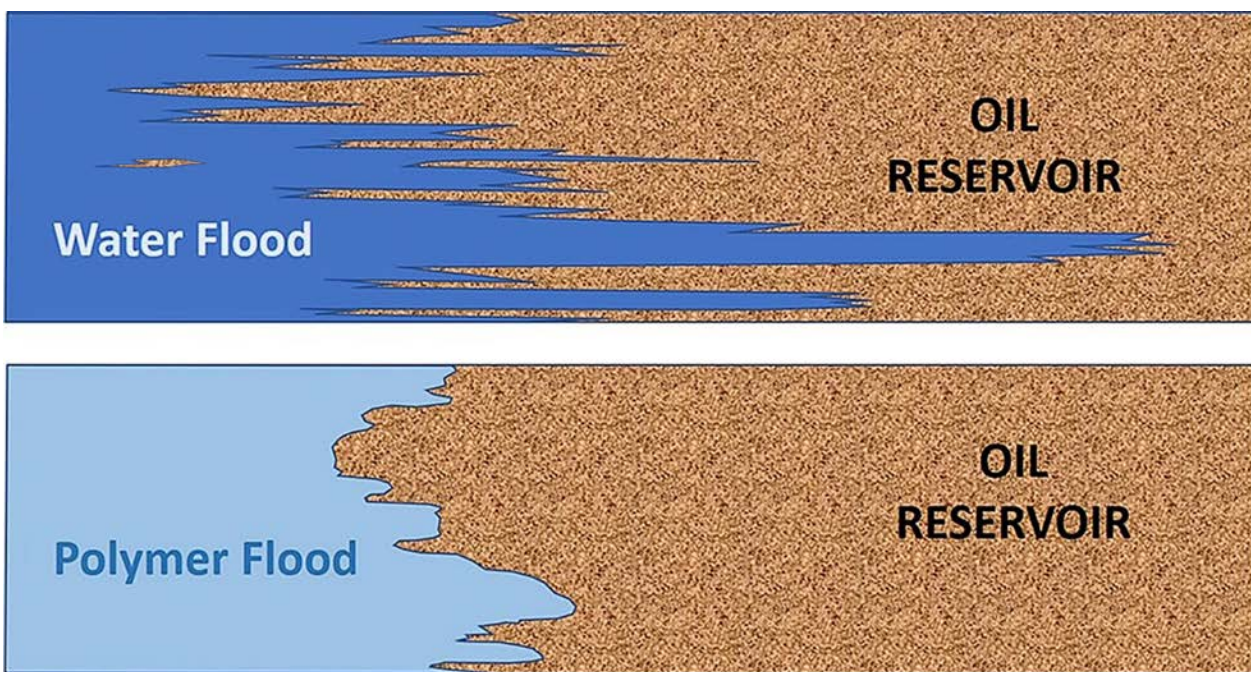

Figure 3. Illustration showing how by improving the mobility ratio, polymer floods can improve reservoir conformance issues compared to normal waterfloods. Flow is from left to right.

Polymer flooding is one of least expensive CEOR methods and has proven particularly useful in improving waterflood performance in many

Minnelusa reservoirs. Polymer floods tend to help alleviate some of the water breakthrough issues and tend to improve sweep efficiency. Due to this tendency, nearly 25 percent of all Minnelusa fields have received some kind of polymer treatment. Historically, polymer flooding in the Minnelusa tends to recover significantly more incremental oil reserves compared to standard waterfloods (Hochanadel, et al, 1990; Thyne, et al, 2010; Mack, 2014).

The incremental cost of polymer is typically about $1 per barrel injected, in 2020 dollars, or roughly $1.7-$16 per incremental barrel of oil recovered (Muggeridge, 2013; Lantz and North, 2014). The higher end of this range is normally not economical and can be due to a variety of factors, including improperly designed well patterns, improper applications of polymer, or leakage out of zone. In most cases, polymer-augmented waterflooding has proven to be an economical method for improving oil recovery in Minnelusa fields.

Minnelusa Polymer Floods in Wyoming

Polymer flooding in Wyoming first began in 1967 at the Skull Creek Oil Field in Weston County (Lane, 1970). The project was designed to inject polymer into the Lower Cretaceous Muddy Formation in order to improve volumetric sweep and conformance. Since that time, there have been 131 commercial-scale tertiary oil recovery projects undertaken in Wyoming, of which 114 (87 percent) involved injecting polymer, according to statistics at the WOGCC.

The first commercial application of a polymer-augmented waterflood in a Minnelusa reservoir occurred in 1972 at Stewart Ranch Field. The practice was then more broadly applied to other fields well into the 1990's. The majority of Minnelusa polymer projects were implemented by major and large independent oil companies prior to their divestment of Wyoming properties in the mid- to late-1980's and 1990's. Many of the established projects were picked up by independent operators who continued polymer operations in their Minnelusa assets into the 2000's. Instances of more recently implemented polymer flooding in the Minnelusa, however, are rare.

In a study comparing 16 waterfloods and 6 polymer floods in the Minnelusa, Mack and Duvall (1984) noted that, on average, the ratio of injected fluids required to recover a barrel of oil was 2.76:1 for a conventional waterflood but only 1.73:1 for a polymer flood. Another way of expressing this comparison is that the polymer floods examined required about 40 percent less injection to recover the same volume of oil.

In a similar study comparing 24 Minnelusa waterfloods to 31 Minnelusa polymer floods, Hochanadel, et al. (1990), concluded that at equal injection volumes, polymer floods recover more oil and produce less water than conventional waterfloods. A corollary to that statement is that at equal oil recoveries, polymer floods have lower injection volumes, less water production, and recover oil more quickly than do conventional waterfloods. The paper also concluded that the polymer floods studied recovered an additional 7.5 percent of the OOIP compared to conventional waterfloods alone at a total chemical and equipment cost of about $1.69 per incremental barrel of oil recovered.

Of the 114 polymer floods initiated in Wyoming, 76 projects involved polymer injection into the Minnelusa Formation. Approximately 63 percent of these projects have resulted in positive responses. There are several possibilities to explain the failures, but one likely reason is due to a lack of proper reservoir characterization and resulting poor flood design.

To better analyze the effectiveness of Minnelusa polymer floods, the 76 projects were subdivided into three categories based on the way data are recorded at the WOGCC: (1) polymer alone (including surfactant-polymer (SP) and alkaline-surfactant-polymer (ASP)), (2) infill drilling plus polymer, and (3) commingled production plus polymer (Figure 4).

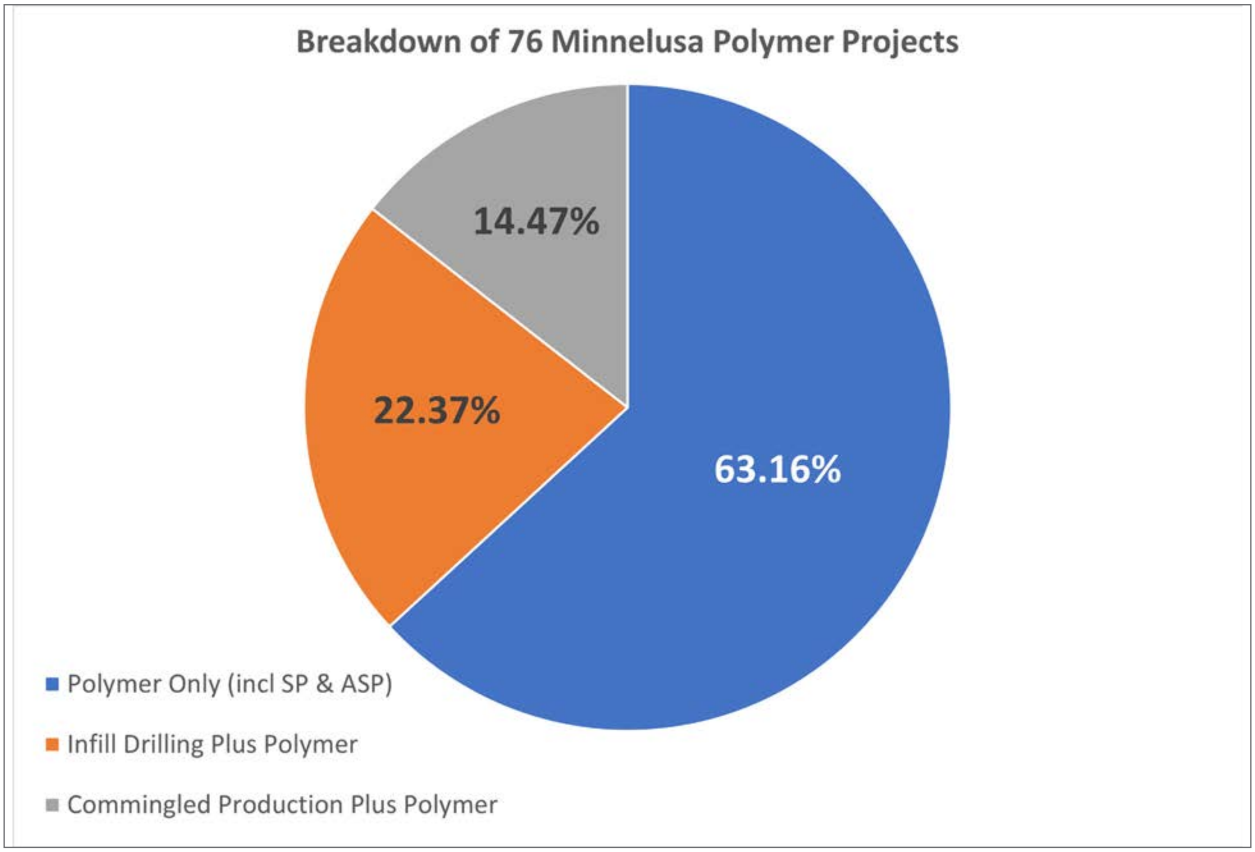

Figure 4. Pie chart showing the subdivisions of Minnelusa polymer floods in Wyoming.

Fields chosen for evaluation in this report were selected using the following criteria: (1) reported polymer-augmented waterflood, (2) the number of producing wells did not change over the life of the flood, (3) there was no commingled production within the field, and (4) production and injection data were available. Known ASP floods were excluded from this report since the chemical costs are significantly higher and more variable than polymer floods, making it exceedingly difficult to determine the cost-effectiveness of those floods without input from operators or companies involved with those floods.

Due to limitations of the publicly available data from the WOGCC, it is not possible to evaluate production or injection data prior to 1978. Published articles and supplemental information from operators or vendors supplying the chemical for polymer flooding were utilized when possible to fill gaps in the WOGCC data.

Graphs of production and injection data were used to establish average primary and secondary decline rates. Key assumptions applied to the production curves include: (1) chemical costs were fixed at one dollar per injected barrel, in 2020 dollars, and (2) any production above the average secondary decline rate is considered incremental production. Estimated chemical cost per incremental barrel of oil produced were calculated for each field based on the ratio of total injected fluid during the polymer flood divided by incremental oil produced.

Of the 48 Minnelusa polymer floods that did not have infill drilling or commingled production, 24 fields were selected for examination in this report based on the quality of available data (Table 1). These fields were evaluated to determine the apparent economic viability of the polymer flood (Figure 5).

Table 1. List of Minnelusa polymer floods discussed in this report.

Field Name	Dis-covery Year	Polymer Injection	API	Cum Oil (BO)	Incremental Oil (IBO) Due to Polymer	Polymer Cost/IBO
Adon Road	1962	9/1990-1/96	20	2,774,547	617,463	$3.45
Ash	1987	1/1993-1/94	19	1,035,674	78,826	$6.21
Big Mac	1985	6/1986-1/91	22	1,053,054	208,936	$4.82
Bishop Ranch	1963	12/1988-1/91	34	796,316	38,565	$14.55
Candy Draw	1985	5/1987-4/2000	27	4,195,391	1,533,758	$4.93
Edsel	1981	5/1984-1/99	21	5,892,772	1,902,500	$7.44
Hamm	1967	10/1975-1/85	20	8,214,145	1,700,000	$1.14
Kummer-feld	1960	4/1975-	36	13,051,724	819,700	??
Lad	1971	2/1982-7/89	21	4,692,828	642,367	$2.46
Lily	1985	11/1987-11/95	22	3,784,067	570,984	$2.85
OK	1973	1/1975-12/83	29	3,549,665	>300,000	??
Ottie Draw	1985	6/1990-9/98	30	1,355,705	168,858	$10.72
Rainbow Ranch N	1973	7/1987-11/88; 3/1993	23	3,620,353	1,327,074	$1.41
Right A Way	1982	11/1985-6/99	20	1,400,335	128,105	$16.77

Rule	1986	2/1991-9/2001	26	1,510,109	237,666	$3.39
Semlek West	1962	9/1973-3/77	23	??	??	??
Simpson Ranch	1971	7/1979-8/83	24	1,340,538	124,644	$4.70
Spirit	1991	10/1991-7/96	27	691,509	48,096	$16.82
Stewart	1965	1972-1977	22	16,424,716	??	??
Straag Draw	1989	8/1992-7/1996	26	194,006	51,964	$9.71
Super-hornet	1989	2/1994-9/1999	21	1,276,744	270,274	$7.74
T. A. Buttes	1987	6/1989-11/97	24	1,056,900	347,890	$2.34
Trout Pond	1994	11/1997-1/2001	22	1,844,092	397,939	$2.28
Victor	1984	4/1987-4/1991	21	2,256,276	380,381	$3.20

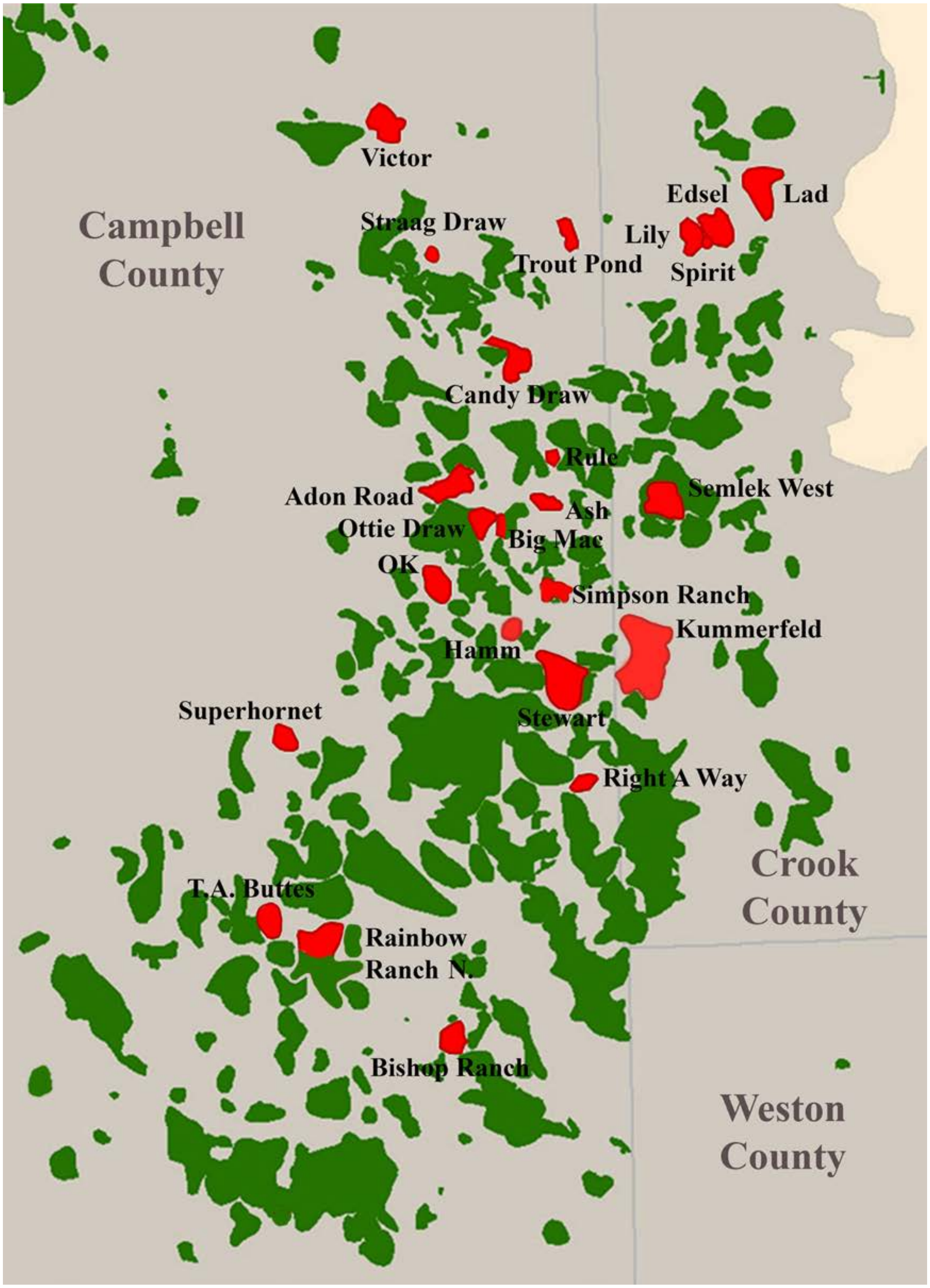

Figure 5. Map of the 24 Minnelusa polymer floods in the Powder River Basin discussed in this report.

Assessing Incremental Production

Production decline curves are normally used to assess reservoir performance and typically show a relatively steady, exponential decline rate unless something occurs to alter production, such as (1) increasing injection rates, (2) changing the number or status of wells in the field, (3) water breakthrough, (4) deployment of improved or enhanced recovery projects, or (5) any combination of the aforementioned events.

Commonly, with all other factors being static, a standard waterflood in the Minnelusa produces a sharp increase in production that begins declining at an exponential rate at a significantly higher baseline than in the case of the field under primary production (Figure 6a). This decline rate tends to be relatively consistent unless additional changes are made in the field.

A polymer-augmented waterflood tends to produce an observable, temporary period of increased production that is greater than a conventional-water-flood-induced increase. This polymer-induced increase is revealed on a production graph as a bump in production above the normal exponential decline rate of a conventional waterflood (Figure 6b).

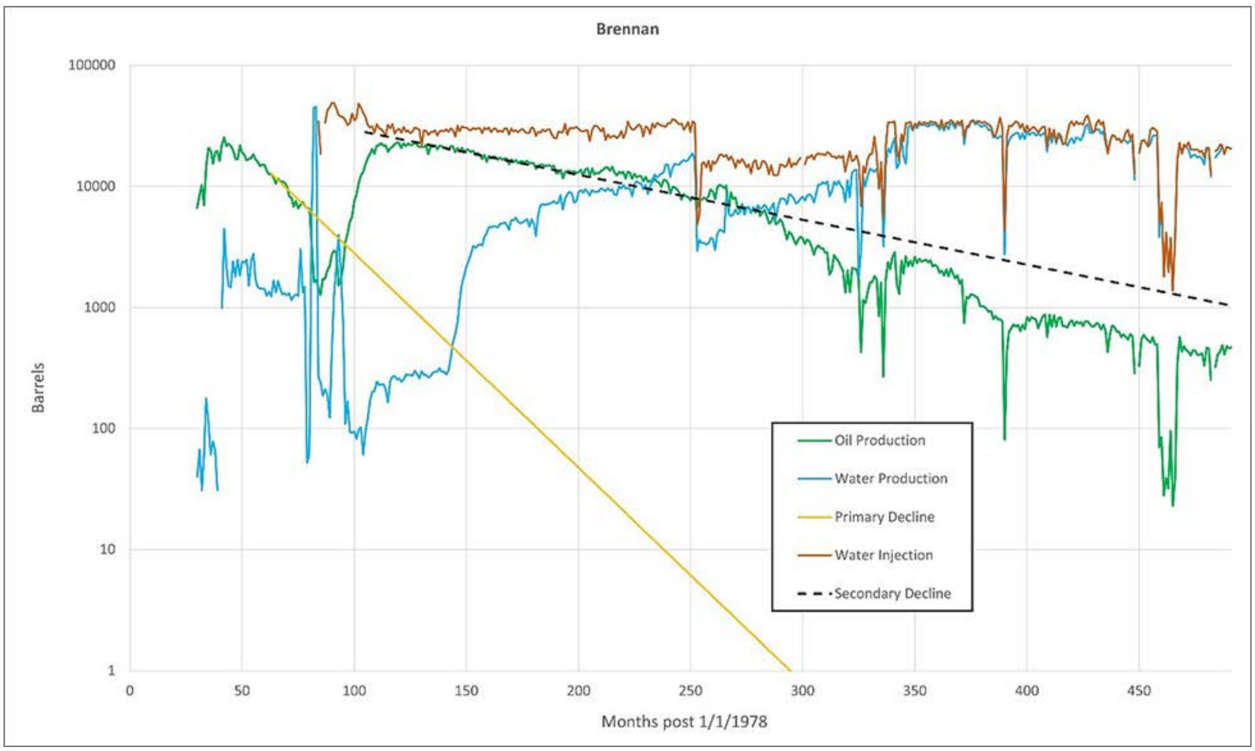

Figure 6a. Production graph for Brennan Field illustrating the typical exponential decline rate of a conventional waterflood in the Minnelusa.

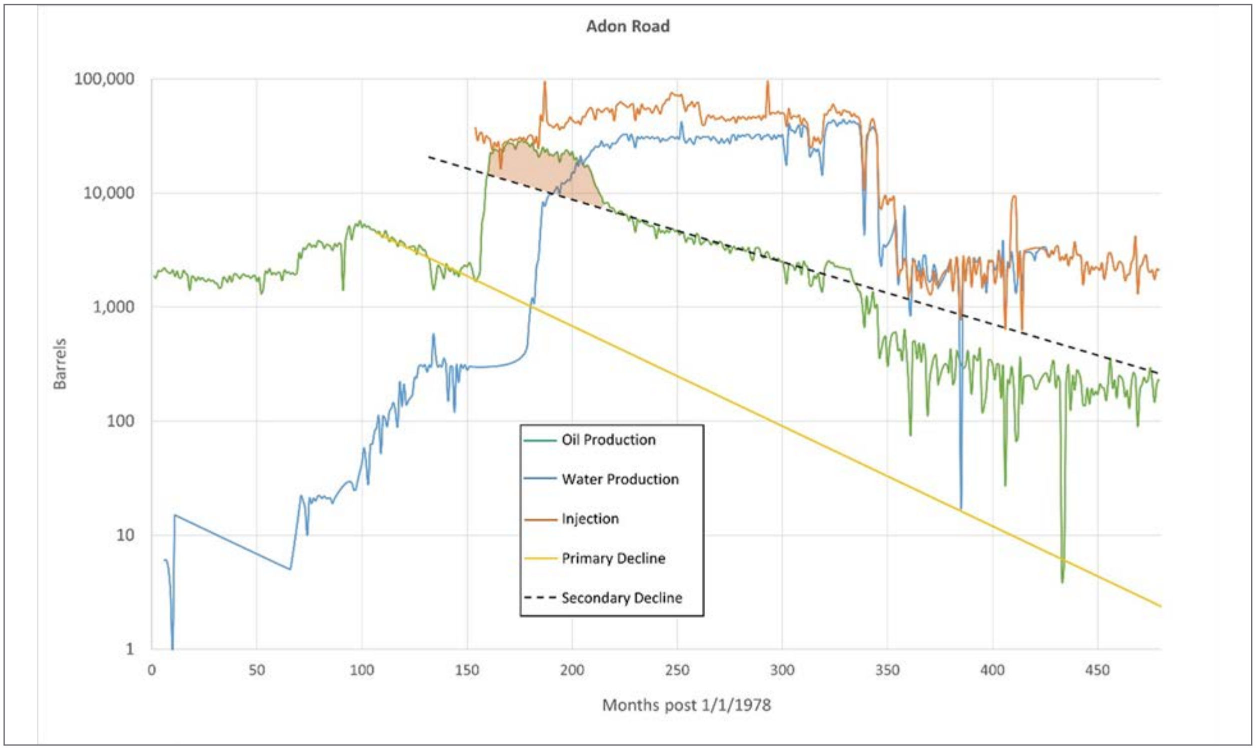

Figure 6b. Production graph for Adon Road Field illustrating a typical production response to a polymer-augmented waterflood in the Minnelusa. The shaded area above the average Secondary Decline Rate indicates the incremental oil production due to polymer.

Synopses of Published Studies on Minnelusa Polymer Floods

Big Mac: Located in northeastern Campbell County (T52N-R69W) this field was discovered in 1985 and has produced a little over 1 million barrels of oil to date (Figure 7). The Dykstra-Parson coefficient here is 0.5, which is low for the Minnelusa (Lantz and North, 2014), indicating layers of moderately heterogeneous permeability.

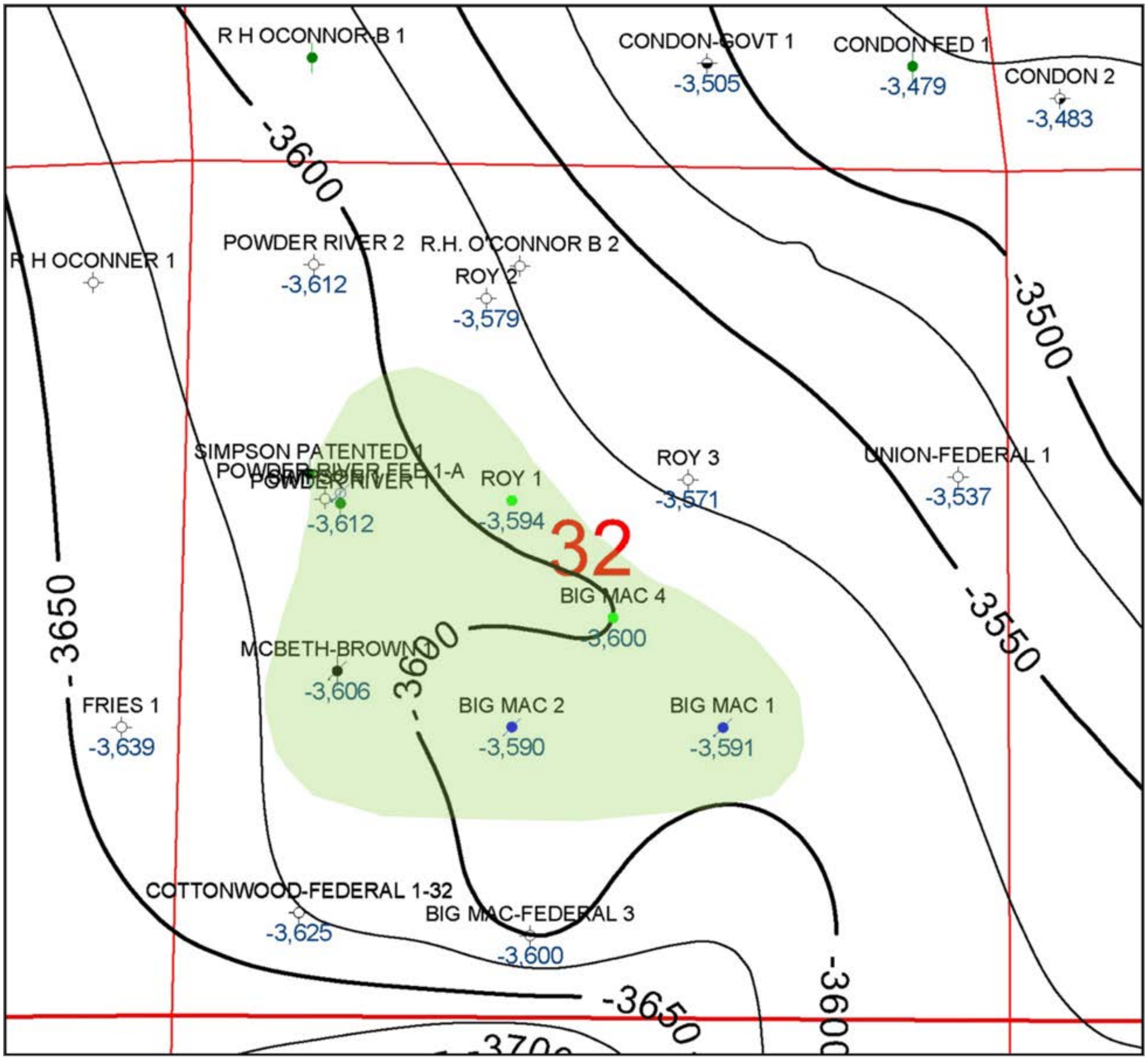

Figure 7. Big Mac Field (T52N-R69W), Campbell County, Wyoming. Contours are subsea values on the top of the Minnelusa.

Water breakthrough encouraged the operator to try a CDG flood starting in May 1986. The initial well pattern for the flood comprised four producers (Powder River #1-A, Roy #1, Big Mac #1, and Big Mac #2) and one converted injector (McBeth-Brown #1). The Big Mac #4 was drilled in April 1991 and did play a role in the polymer flood. The design of the polymer flood is summarized in Table 2.

Table 2. Chemical injection plan at Big Mac Field.

STAGE	CHEMICAL	CHEMICAL WT (lbs)	BBLS INJECTED	CONCENTRATION (ppm)
1	Cationic Polymer	16,000	122,004	375
2	Anionic Polymer	15,475	122,786	360
3	CDG	15,910	131,995	345
4	Anionic Polymer	4,525	61,242	211
5	CDG	34,360	407,154	241
6	Anionic Polymer	3,900	60,000	225

The polymer flood continued from May 1986 to April 1991. As reported by Lantz and North (2014), all four producing wells responded to the polymer injection. The McBeth-Brown #1 injection well was shut-in during September 1995 and ultimately plugged and abandoned in July 1996. Lantz and North reported the incremental oil recovery from the polymer flood to be 248,500 barrels at a chemical cost of $0.95 per incremental barrel of oil recovered.

A review of this polymer flood suggests that rather than the total of 905,181 barrels of water/polymer injected as reported by Lantz and North (2014), based on data from the WOGCC, the total injection during this period was 1,008,022 barrels. By projecting the average conventional waterflood decline rate through the production curve, the incremental oil production due to polymer is about 209,000 barrels (Figure 8). Using these numbers, and assuming the cost per injected barrel is $1, the chemical cost per incremental barrel of oil produced is $4.82 on this flood.

The difference in the chemical cost per incremental barrel can be due to pessimistic assumptions on the average conventional waterflood decline rate and associated incremental oil amounts or on the total cost of chemicals. In any case, for the purposes of this paper, similar decline curve analyses and chemical cost figures based on injection volume during polymer treatment can provide a relative assessment regarding which polymer floods were more economic. The reader can determine which chemical cost seems more relevant for assessment purposes.

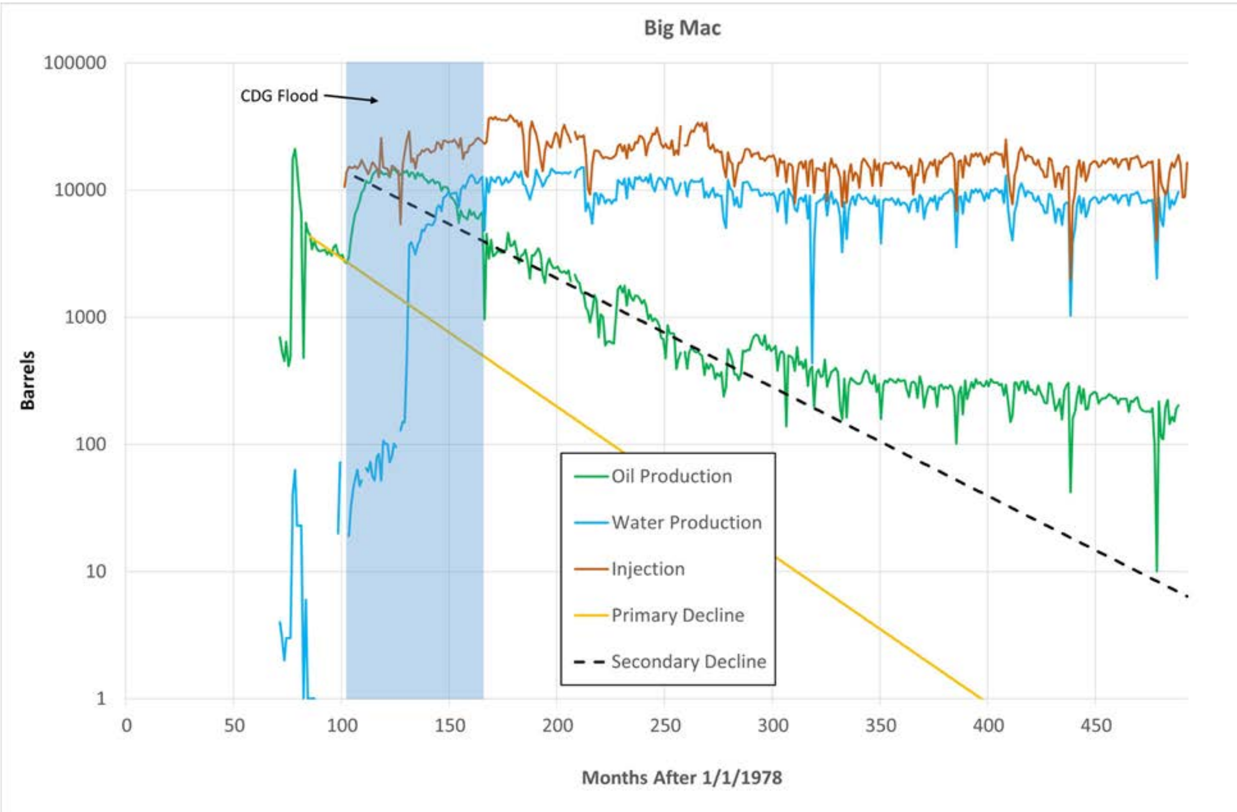

Figure 8. Production graph of the Minnelusa reservoir at Big Mac Field, Campbell County, Wyoming.

Edsel Field: This field, located in Crook County (T54N-R68W), was discovered in 1981 and has since produced nearly 5.9 million barrels of oil (Figure 9). A polymer-augmented waterflood was initiated in 1984 and in 1985 was switched to the first ever field-wide application of CDG (Manrique & Lantz, 2011). According to the authors, the CDG flood resulted in an incremental recovery of 11.5 percent of the original oil in place.

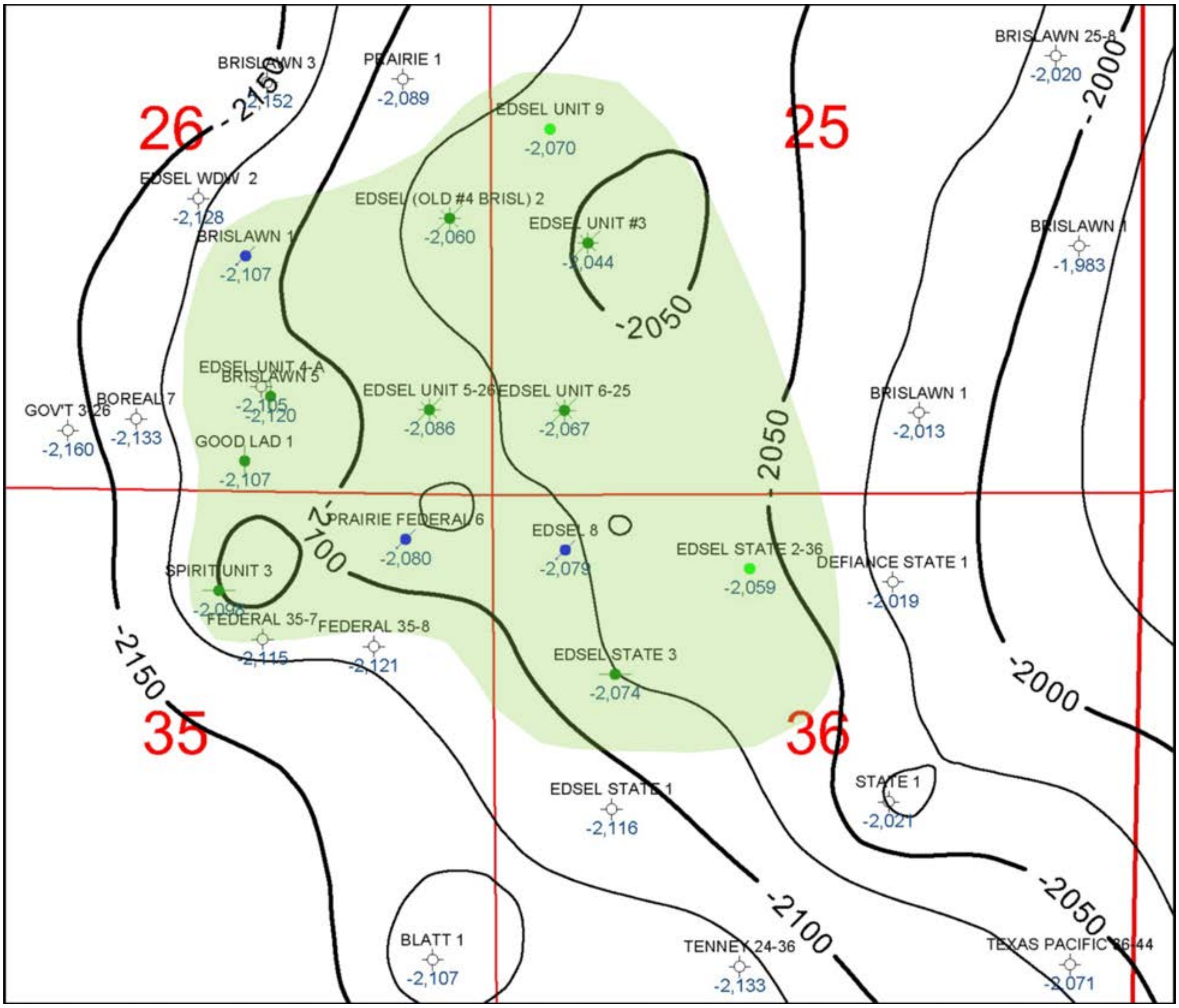

Figure 9. Base map of Edsel Field (T54N- R68W), Crook County, Wyoming. Contours are subsea values on the top of the Minnelusa.

The production data for this field suggests that the incremental oil recovered due to the polymer-augmented waterflood was a little over 1.9 million barrels (Figure 10). If polymer were injected for the entire period from the onset of injection until month 192, when the injection volume changed significantly, total chemical cost would be $14,157,727 assuming costs were $1 per injected barrel. Using those numbers, the chemical cost per incremental barrel of oil recovered is $7.44.

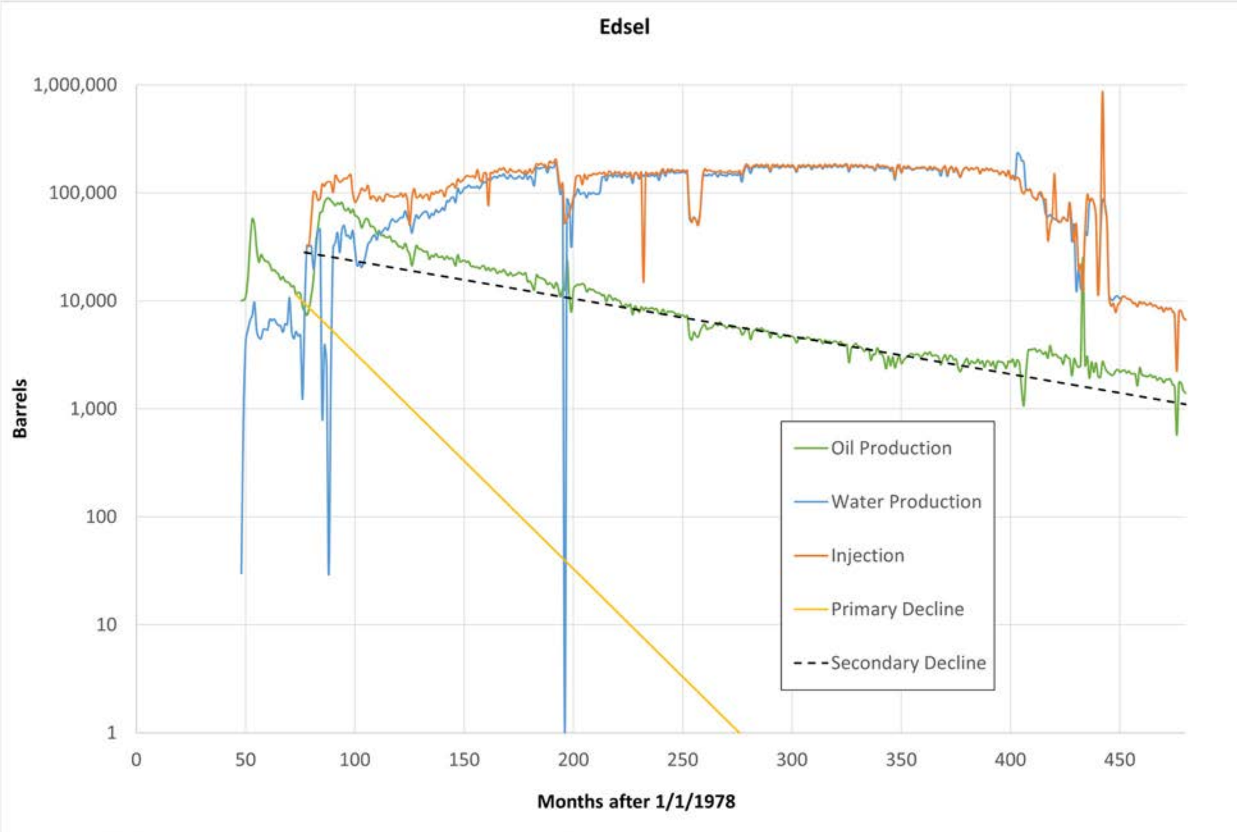

Figure 10. Production graph for Edsel Field, Crook, Wyoming. Exact dates for the polymer flood are unknown.

Hamm Field: This field (Figure 11), located in Campbell County, Wyoming (T51N-R69W), was discovered in March 1966 and has produced over 8.2 million barrels of oil. A waterflood was initiated in April 1974 when the Hamm Unit #4 well (formerly the Heptner #2) was converted to injection. Water breakthrough occurred rapidly in the Hamm Unit #3 and it was shut in during November 1976. Water cuts increased in the Hamm #1 and two separate chemical tracer tests in March 1978 and October 1980 confirmed rapid water movement from the Hamm Unit #4 to the three remaining producers, the Hamm #2, Hamm #6, and Hamm #1 (Doll and Hanson, 1987). The Hamm Unit #9 was completed in June 1984, but its initial production was 0.69 barrels of oil per day (BOPD) and 453 barrels of water per day (BWPD) and ultimately plugged and abandoned in November 2003.

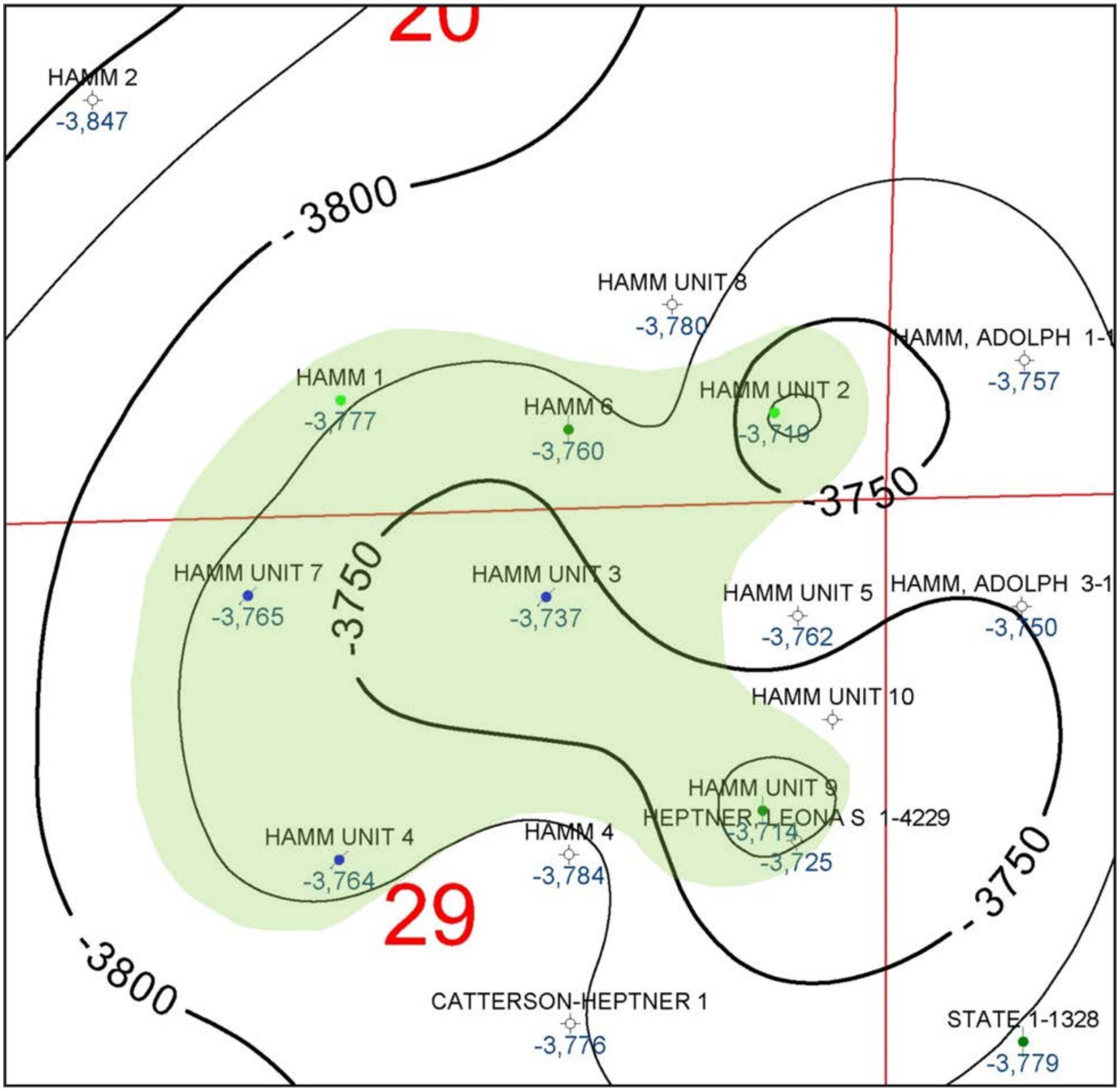

Figure 11. Hamm Field (T51N-R69W), Campbell County, Wyoming. Contours are subsea values on the top of the Minnelusa.

The Dykstra Parsons coefficient in this reservoir was 0.76 with a mobility ratio of 17.3, both numbers explaining the reasons for the rapid water breakthroughs. A polymer flood was designed to reduce permeability variations by using a combination of a Cat-An treatment and in-situ gelling.

The initial injection of cationic polyacrylamide would go into the high permeability zones where its excellent adsorption/retention properties would provide an anchor for the anionic polyacrylamide injected next. Subsequent in-situ gelation was intended to provide in-depth permeability unification by building progressive layers of resistance to water flow in the formation due to the crosslinking with the anionic polymer.

According to Doll and Hanson (1987), polymer injection began at the Hamm Unit #4 in October 1975 and continued through January 1985 (Table 3). Polymer was also injected in the Hamm Unit #7 well starting in 1978 (Table 4) and in the Hamm Unit #3 starting in 1982 (Table 5). Total polymer injection is noted in Table 6.

Table 3. Hamm Unit #4 Chemical Injection (after Doll and Hanson, 1987)

YEAR	POLYMER WT (lbs)	WATER INJECTED (bbls)	CROSSLINKER (lbs)
1975	15,000	219,297	24,200
1976	59,600	858,150	35,800
1977	67,025	827,194	0
1978	61,275	753,230	30,000
1979	54,200	800,842	0
1980	63,450	688,605	0
1981	76,760	813,111	0
1982	56,830	614,815	0

Table 4. Hamm Unit #7 Chemical Injection (after Doll and Hanson, 1987)

YEAR	POLYMER WT (lbs)	WATER INJECTED (bbls)	CROSSLINKER (lbs)
1978	3,275	75,346	0
1979	18,250	191,886	24,000
1980	31,850	252,938	24,000
1981	15,890	86,797	0
1982	6,260	56,250	0

Table 5. Hamm Unit #3 Chemical Injection (after Doll and Hanson, 1987)

YEAR	POLYMER WT (lbs)	WATER INJECTED (bbls)	CROSSLINKER (lbs)
1982	25,050	196,871	44,000
1983	51,150	464,624	131,170
1984	29,9080	300,635	3,200
1985	2,350	24,525	0

Table 6. Total polymer injection at Hamm Field (after Doll and Hanson, 1987)

CHEMICAL INJECTED	WEIGHT (lbs)
Cationic Polymer	10,000
Anionic Polymer	629,115
Crosslinker	314,770
Complexing Agent	3,200

In their 1987 report, Doll and Hanson noted that the polymer flood was exceedingly successful. Water production decreased dramatically during the period of the chemical flood while oil production increased over conventional waterflood levels. Incremental oil production was 1.7 million barrels with a total claimed chemical cost amounting to $1.14 per incremental barrel of oil produced.

Due to the lack of production and injection data publicly available from the WOGCC prior to 1978, it is not possible to independently verify the conclusions drawn by Doll and Hanson. It is reasonable to agree with the assessment regarding the success of this polymer flood based on the data presented in their 1987 report.

Kummerfeld: Kummerfeld Field (T50 & 51N-R68W, Crook County, Wyoming) was discovered in 1960 and has produced in excess of 13 million barrels of oil from Minnelusa and Dakota sandstones (Figure 12). Mack (1978) noted that the Minnelusa reservoir in this field has variable permeabilities (Dykstra-Parsons coefficient of 0.71) and exhibits an extreme mobility ratio of 18. At the time waterflooding was initiated in April 1973, the field contained three injection wells and six producers. High water cuts indicated that the waterflood was not effectively sweeping the reservoir.

A Cat-An polymer treatment was conducted beginning in April 1975 in an attempt to deal with the conformance issues (permeability variations) in the reservoir. Following this treatment, Hall slope data, commonly used to analyze injectivity (Buell, et al, 1990), indicated that the permeability issues were still a problem (Mack, 1978). Two sequences of in-situ gelling polymers (anionic polymer plus aluminum) were then injected and subsequent Hall slope graphing indicated that the injection profiles were improved.

Mack (1978) noted that the chemical treatments had stabilized oil production at about 700 to 800 BOPD for nearly three years. Projected incremental oil recovery due to the chemical treatment was estimated to be 819,700 barrels. Field results show that the Cat-An and in-situ gelling processes are superior to straight polymer for improving oil recovery, reducing produced water, and provide better cost performance. Reported incremental oil recoveries ranged from 3 to 16 barrels of oil per pound of anionic polymer used. This ratio is optimistic compared to the more commonly quoted range of 0.6 to 1.4 barrels of oil per pound of polymer (Pope, 2007).

Since publicly available data from the WOGCC lack detailed production and injection volumes prior to 1978, it was not possible to effectively evaluate the effects of the polymer treatments beyond what was indicated in the report by Mack.

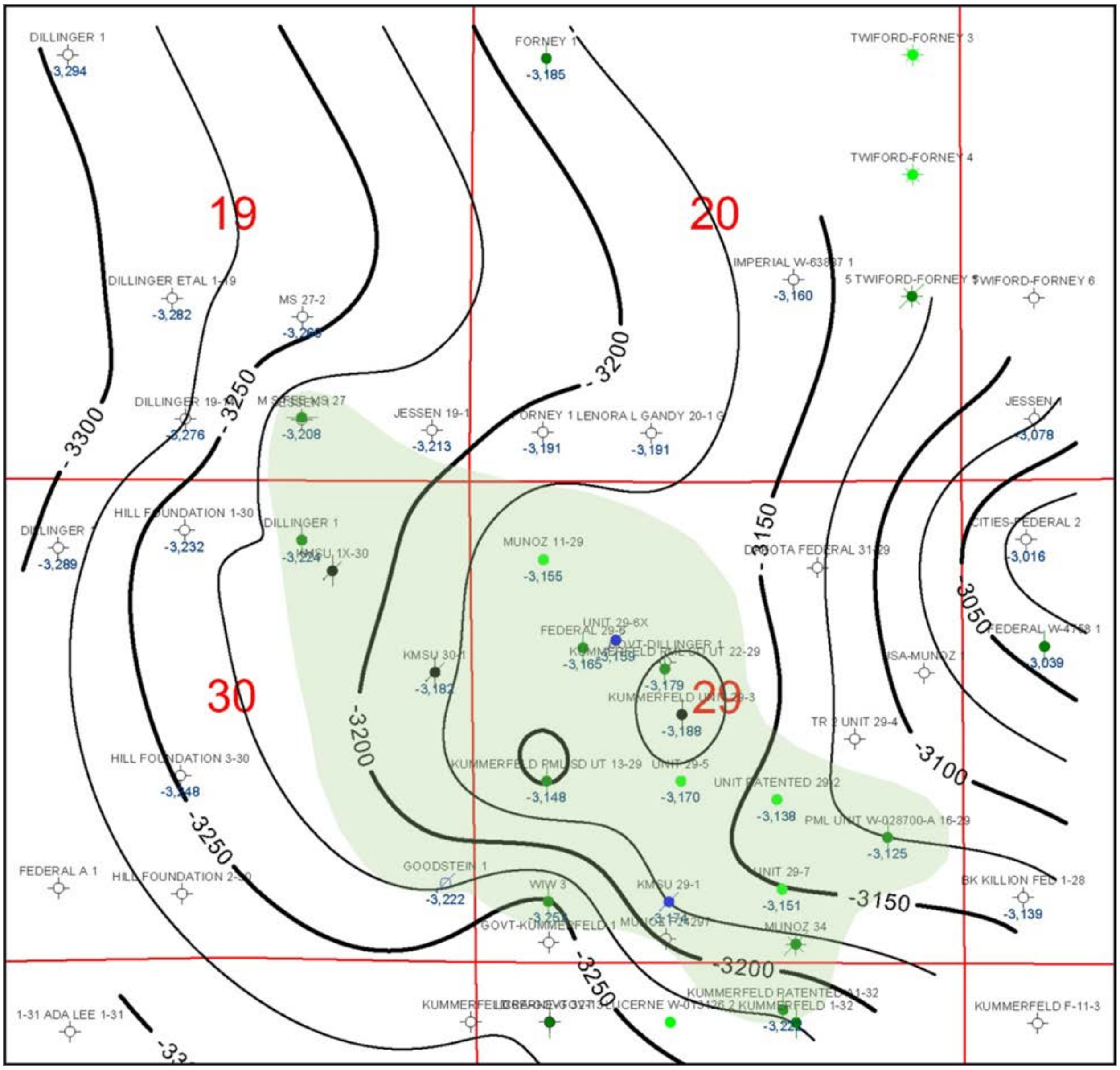

Figure 12. Kummerfeld Field (T51N-R68W) Crook County, Wyoming. Green circles are Minnelusa producers; blue circles indicate Minnelusa injectors. Contours are subsea values on the top of the Minnelusa.

OK: Located in Campbell County, OK Field was discovered in 1973 (Figure 13). Air permeability measurements of the Minnelusa reservoir ranged from 1 millidarcy (mD) to 3,000 mD and exhibited a mobility ratio of 8.5 (Mack, 1978).

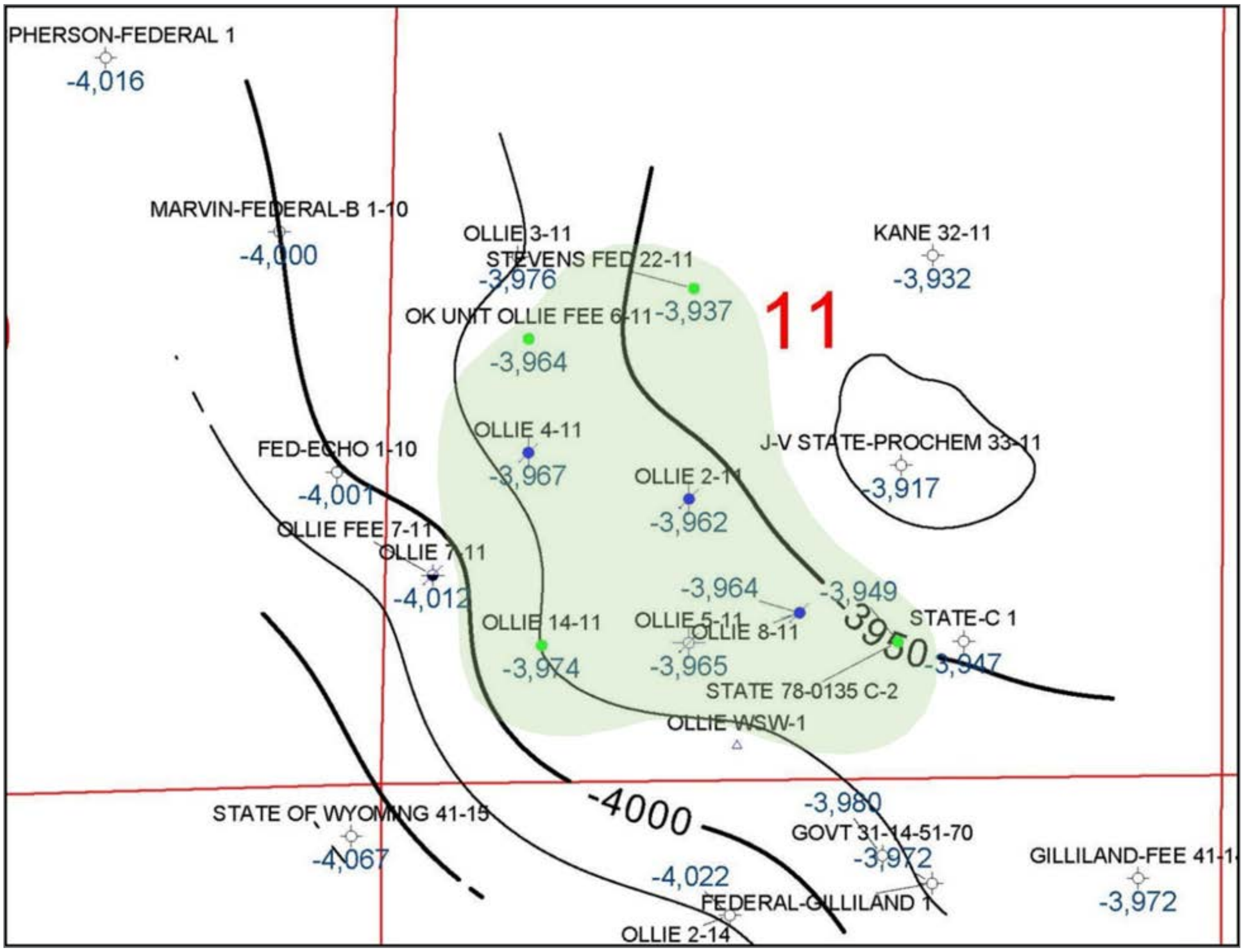

Figure 13. Base map of OK Field. Contours are subsea values on the top of the Minnelusa.

At the time waterflooding was initiated in October 1975, there were 4 productive wells and one injector, the Ollie #5-11. Response to this injection was rapid, with field-wide oil production increasing to approximately 22,000 barrels per month by the end of the year.

Three months later, in January 1976, a Cat-An polymer treatment was initiated in this same well with injection of a cationic polymer followed by a volume of anionic acrylamide. The sequence of chemicals injected into this well is listed in Table 7.

Table 7. Chemical injection Ollie #5-11 well in OK Field (after Surkalo, et al., 1986)

STAGE	CHEMICAL	CHEMICAL WT (lbs)	BBLS INJECTED	CONCENTRATION (ppm)
1	Cationic Polymer	23,000	172,387	381
2	Anionic Polymer Aluminum Citrate	300 8,700	63,325 4,304	226 ---

3	Anionic Polymer Aluminum Citrate	5,800 600	69,372 27,127	239 ---
4	Anionic Polymer Aluminum Citrate	7,300 600	132,785 27,235	257 ---
5	Anionic Polymer Aluminum Citrate	26,000 302	286,643 610	160 ---
6	Anionic Polymer	5,800	183,475	90
7	Anionic Polymer	12,000	260,341	132

Immediately following the Cat-An treatment, the first ever field-wide application of in-situ gelling was attempted involving the injection of three sequences of aluminum citrate and an anionic polymer. Straight anionic polymer followed the in-situ gelling to maintain the previous build-up of resistance to water flow. Field-wide oil production increased to an average of nearly 25,000 barrels per month before starting to decline in late 1978 (month 37 in Figure 14).

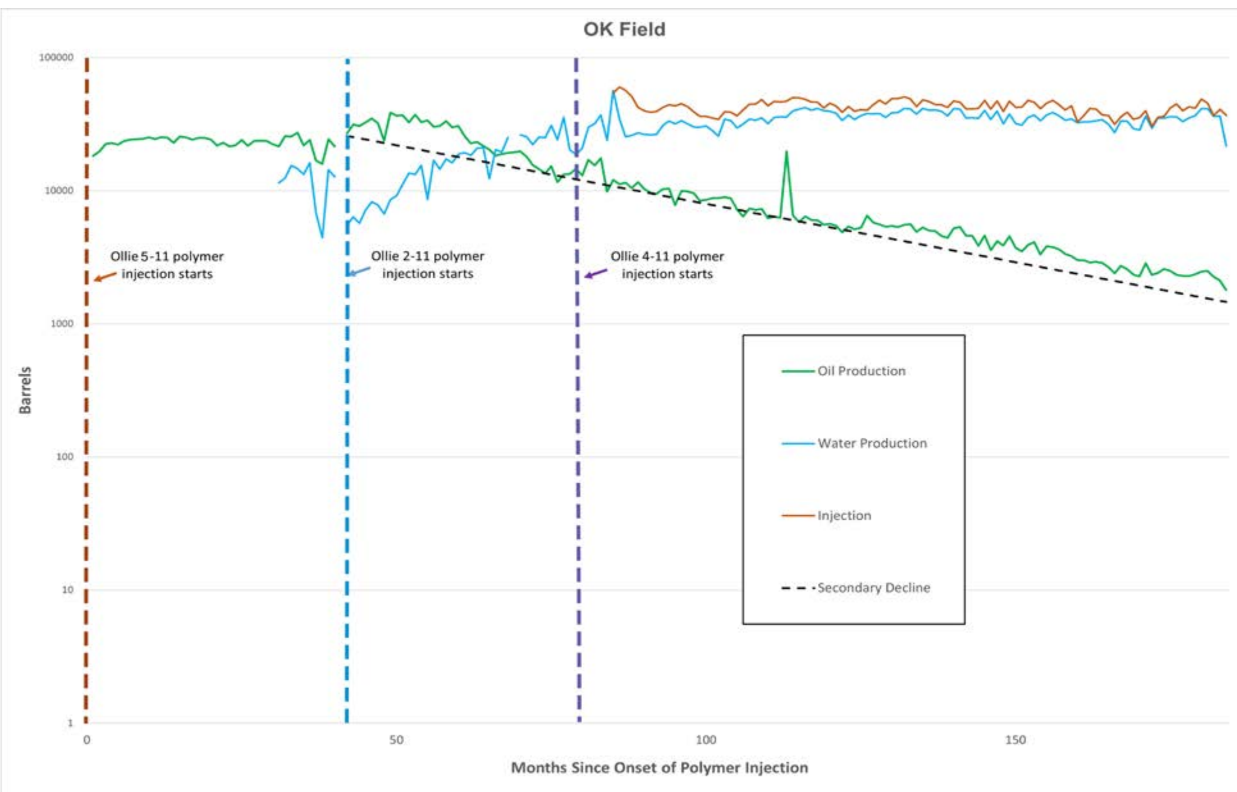

Figure 14. Production graph of the Minnelusa reservoir at OK Field, Campbell County, Wyoming.

In May 1979 (month 41 on graph), the Ollie #2-11 was converted to polymer injection to deal with vertical conformance issues. Table 8 lists the treatment sequence. This injection resulted in an immediate increase in oil production from roughly 23,200 barrels per month to a peak of over 38,000 barrels in 1980 (month 49 on graph).

Table 8. Chemical injection Ollie #2-11 well in OK Field (after Surkalo, et al., 1986)

STAGE	CHEMICAL	CHEMICAL WT (lbs)	BBLS INJECTED	CONCENTRATION (ppm)
1	Cationic Polymer	5,000	20,010	714
2	Anionic Polymer Aluminum Citrate	7,325 315	67,695 ---	309 ---
3	Anionic Polymer Aluminum Citrate	16,925 2,520	180,381 ---	268 ---
4	Anionic Polymer Aluminum Citrate	16,050 1,147	236,151 ---	194 ---
5	Anionic Polymer Aluminum Citrate	14,650 2,032	195,470 ---	214 ---
6	Anionic Polymer Aluminum Citrate	8,800 1,945	84,293 ---	298 ---
7	Anionic Polymer Aluminum Citrate	38,950 204	375,243 204	296 ---
8	Anionic Polymer Aluminum Citrate	3,725 430	34,446 614	309 ---
9	Anionic Polymer Aluminum Citrate	2,875 262	32,349 353	254 ---
10	Anionic Polymer	3,875	36,698	301

In July 1982 (month 79 on graph), the Ollie #4-11 was converted to injection and a polymer treatment commenced to improve the vertical conformance of the reservoir. Table 9 lists the chemical sequence used in this well. This treatment did not have a profound effect on production.

Table 9. Chemical injection Ollie #4-11 well in OK Field (after Surkalo, et al., 1986)

STAGE	CHEMICAL	CHEMICAL WT (lbs)	BBLS INJECTED	CONCENTRATION (ppm)
1	Anionic Polymer Aluminum Citrate	2,075 396	9,184 386	645 48,852
2	Anionic Polymer	1,525	7,947	548
3	Anionic Polymer Aluminum Citrate	650 203	9,416 287	197 33,608
4	Anionic Polymer	850	9,581	253
5	Anionic Polymer Aluminum Citrate	1,375 362	14,635 475	268 36,282
6	Anionic Polymer	1,700	18,130	267
7	Anionic Polymer	1,625	14,629	317
8	Anionic Polymer	775	8,383	264

This polymer flood was considered a success, although it is difficult to prove that the field would have performed differently under just a conventional waterflood. Nevertheless, Surkalo, et al (1986) discuss evidence of chloride concentrations in the produced water along with trends in production volumes that indicate a successful chemical flood. In the same publication, the polymer cost per incremental barrel of oil produced is noted to be $1.01. For some reason, the WOGCC has no injection data prior to 1983 for this field, making an independent assessment impossible.

Rainbow Ranch North: Fielding, et al. (1994), described the polymer-augmented waterflood at Rainbow Ranch Field (Figure 15), located in Campbell County (T49N-R71W). The field was discovered in 1973 with water injection commencing in April 1984, initially with two injection wells and three producers. New drilling in 1984 and in 1986 added two producing wells. Additional development from 1990 to 1992 resulted in four more producers and one injector. The field has produced over 3,620,000 BO.

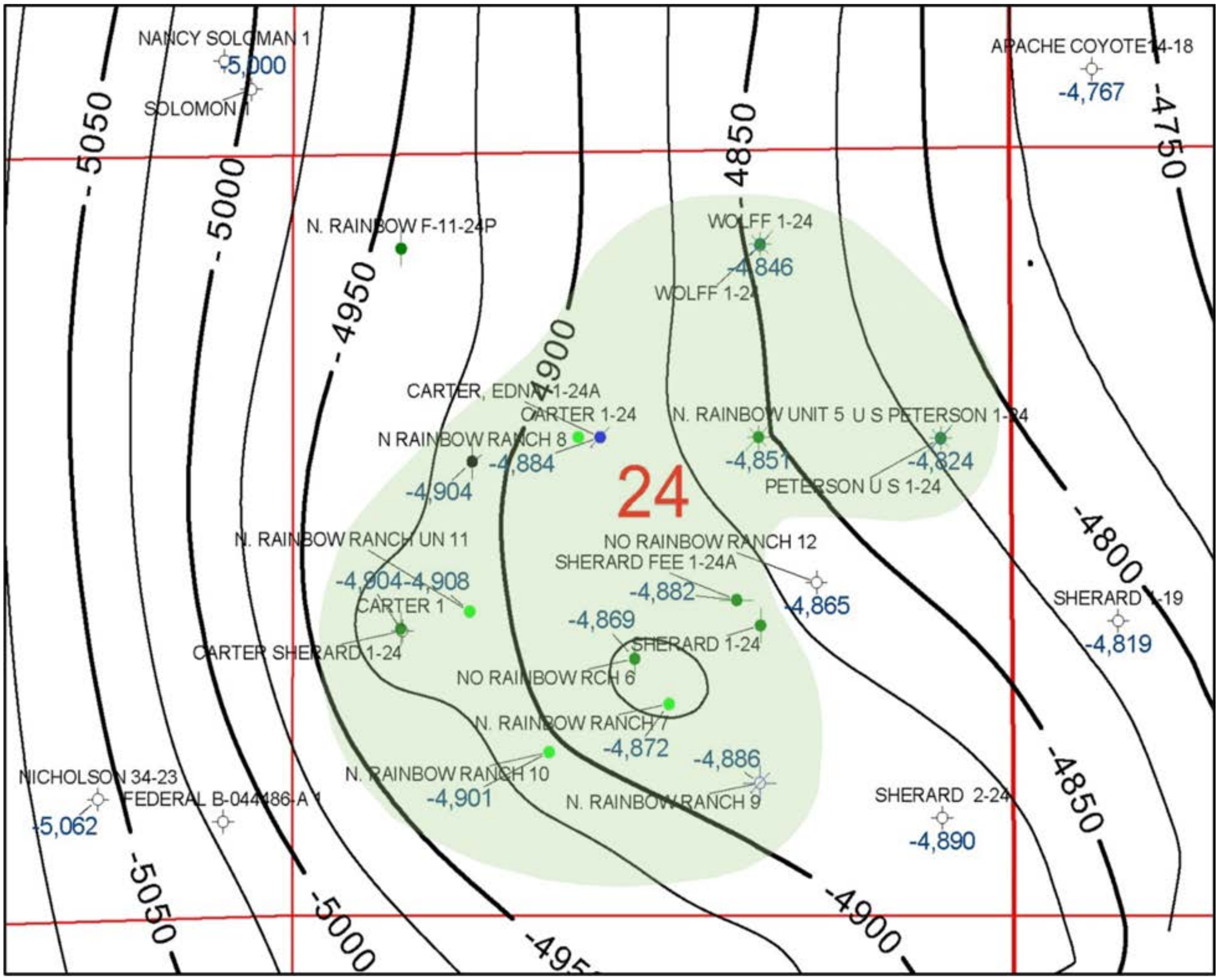

Figure 15. Base map of Rainbow Ranch North Field (T49N- R71W), Campbell County, Wyoming. Contours are subsea values on the top of the Minnelusa.

The Minnelusa reservoir at Rainbow Ranch North Field exhibits a Dykstra-Parsons coefficient of 0.9, indicating a large variance in permeability. A CDG flood was implemented in 1987 due to rapidly increasing water production as result of water breakthrough during the early stages of the waterflood. This polymer-augmented flood continued until February 1990 resulting in injection of a 10 percent pore-volume (PV) slug entirely administered through the Carter #1-24 well.

The CDG program (Table 10) utilized long-term injection using cationic polyacrylamide and anionic polyacrylamide crosslinked with aluminum citrate. Injectivity prior to the CDG process was 1,500 BWPD on a vacuum. At the conclusion of the CDG process, surface injection pressure at the Carter #1-24 well had climbed to 1,000 psi at an average rate of 800 BWIPD (Fielding, et al., 1994). The field water-oil-ratio (WOR) dropped from 2.32 to 2.04.

Table 10. CDG Treatment into the Carter #1-24 well at Rainbow Ranch North Field, Campbell County, Wyoming

STAGE	PRODUCT	WEIGHT (lbs)	BBLS INJECTED	CONCENTRATION (ppm)
1	Cationic Polyacrylamide	22,000	81,000	775
2	Anionic Polyacrylamide	22,500	46,000	1,400
3	Anionic Polyacrylamide Aluminum Citrate	83,100 71,000	198,000	1,200 1,000
4	Anionic Polyacrylamide Aluminum Citrate	68,700 76,000	654,000	300 330

According to Fielding, et al. (1994), the incremental oil recovery due to the CDG program was 300,000 barrels. Manrique and Lantz (2011) claim that the cost of this polymer amounted to about $1 per incremental barrel of oil produced.

Whereas this assessment may be valid, a different case can be argued by examining the production graph for the field (Figure 16). CDG injection from months 115 through 146 resulted in redirecting the waterflood into less permeable portions of the reservoir with a corresponding increase in production starting immediately after CDG injection halted and the polymers set up. As previously mentioned, establishing the incremental oil production due to the CDG injection becomes complicated due to additional drilling and increased injection rates. A general average decline for the post-CDG waterflood can be established (brown dashed line on Figure 14) that would provide a general baseline for the field performance at the increased injection rates and assumably sans the CDG treatment.

Using this assessment, the incremental oil production due to CDG (that portion of the production curve above the Post-CDG Decline rate extending from month 147 to 250) is approximately 671,660 barrels. With 979,000 barrels of polymer-augmented water injected during the program, and at an average cost of $1 per barrel injected, the chemical cost per incremental barrel of oil produced would be $1.46.

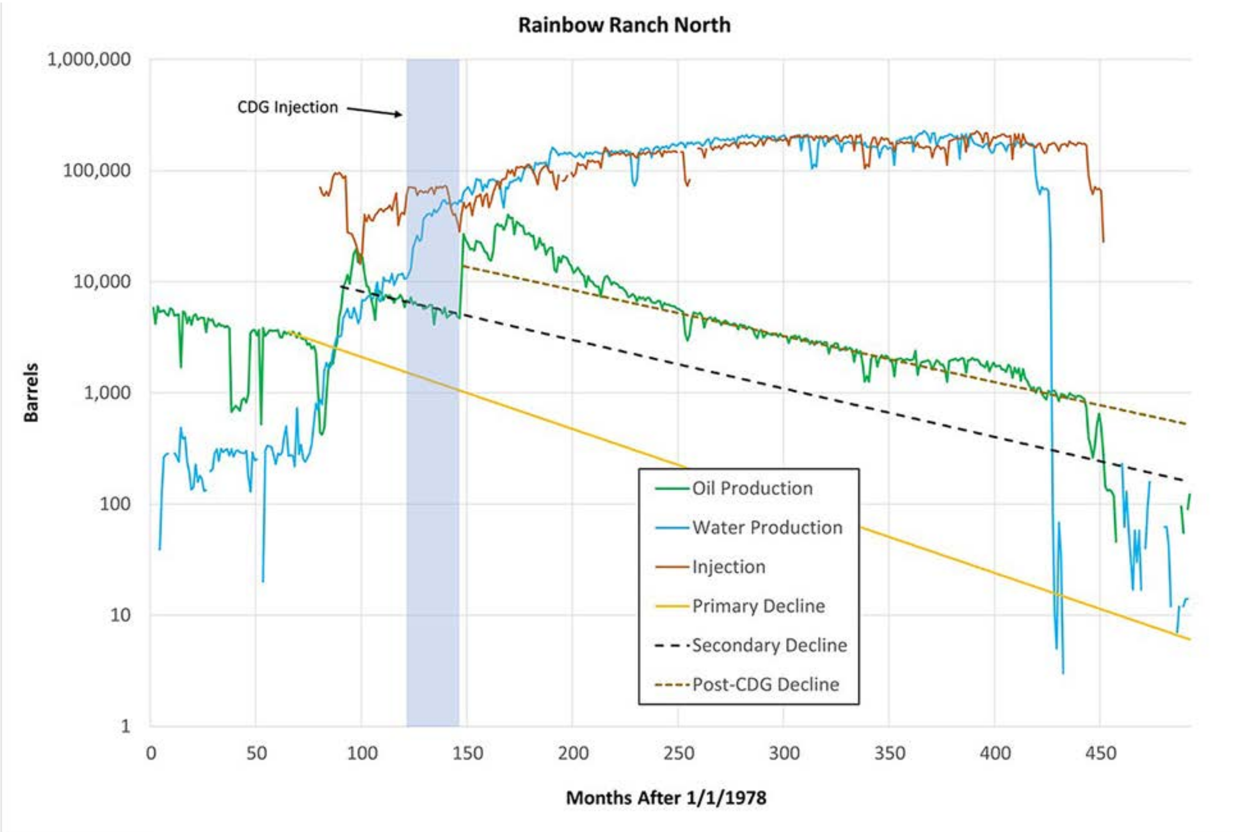

Figure 16. Production graph for Rainbow Ranch North Field, Campbell County, Wyoming.

Semlek West: This field, located in Crook County, Wyoming (T52N-R68W), was discovered in 1962 and has produced over 9 million barrels of oil from the Minnelusa (Figure 17). The Minnelusa reservoir in this field exhibits permeability values ranging from 5 to over 4,000 mD. The Dykstra-Parsons coefficient in the Minnelusa here is 0.81 with a mobility ratio of 8.5 (Tholstrom, 1976; Mack, 1978), which both suggest a conventional waterflood would experience problems. As anticipated, the waterflood initiated in June 1973 saw water cuts climb sharply within three months, prompting the commencement of a Cat-An polymer program in September of that year.

Initially the polymer program comprised one injector and four producers. Oil response to the polymer injection was dramatic and water breakthrough was delayed for 2.5 years. Polymer treatment stopped in early 1977. Due to the lack of available public data from the WOGCC prior to 1978, it is difficult to provide a meaningful update to the prior report on this field.

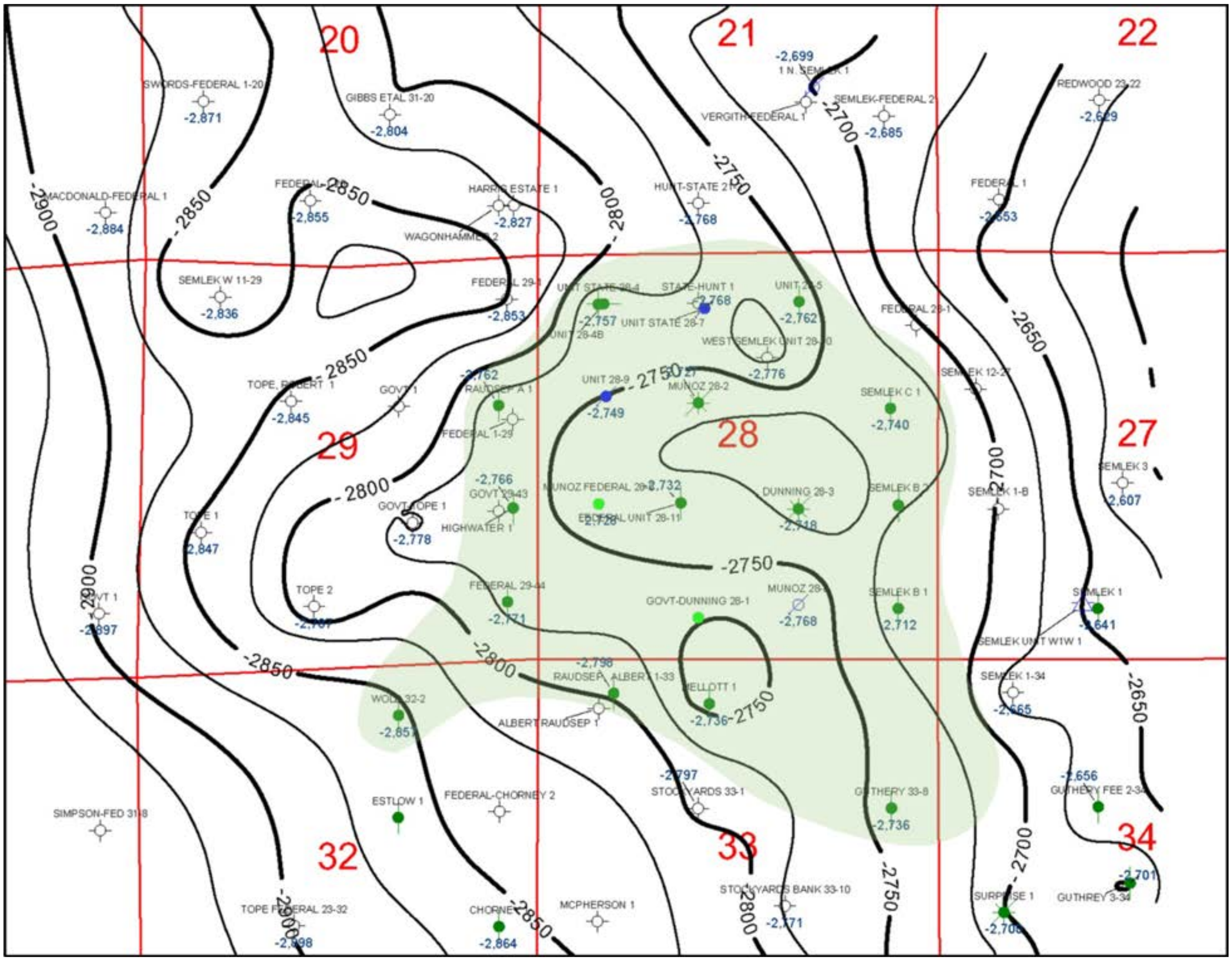

Figure 17. Base map of Semlek West Field (T52N- R68W), Crook County, Wyoming. Contours are subsea values on the top of the Minnelusa.

Simpson Ranch: Discovered in 1971, this field has produced over 1.34 million barrels of oil from five producing wells and one formerly producing well (Simpson Ranch Unit #3) converted to injection (Figure 18). Mack & Duvall (1984) noted that the Dykstra-Parson ratio in the Minnelusa reservoir here is 0.71 and the mobility ratio is about 10, indicating that a conventional waterflood would not provide an efficient sweep of the reservoir. A polymer flood was designed and comprised two processes to reduce the permeability variations: (1) Cat-An polymer process and (2) in-situ gelling.

At the time of the polymer flood, injection was restricted to the Simpson Ranch Unit #3 well with production coming from the Simpson Ranch Unit #1 and #2 wells. Initial injection of anionic polyacrylamide sequenced with aluminum citrate was to provide progressive layers of resistance to water flow within the formation. Anionic polymer is then added which adsorbs to the grains withing the reservoir. Trivalent aluminum ions then link to the anionic polymer. Follow-up polymer is cross-linked by the aluminum ion to form the in-situ gel. Increasing the number of anionic/aluminum sequences increases the in-situ layers and proved greater in-depth residual resistance factors. A mobility control stage follows the in-situ gelling to maintain the previous permeability adjustments and to reduce the high mobility ratio by increasing the water viscosity.

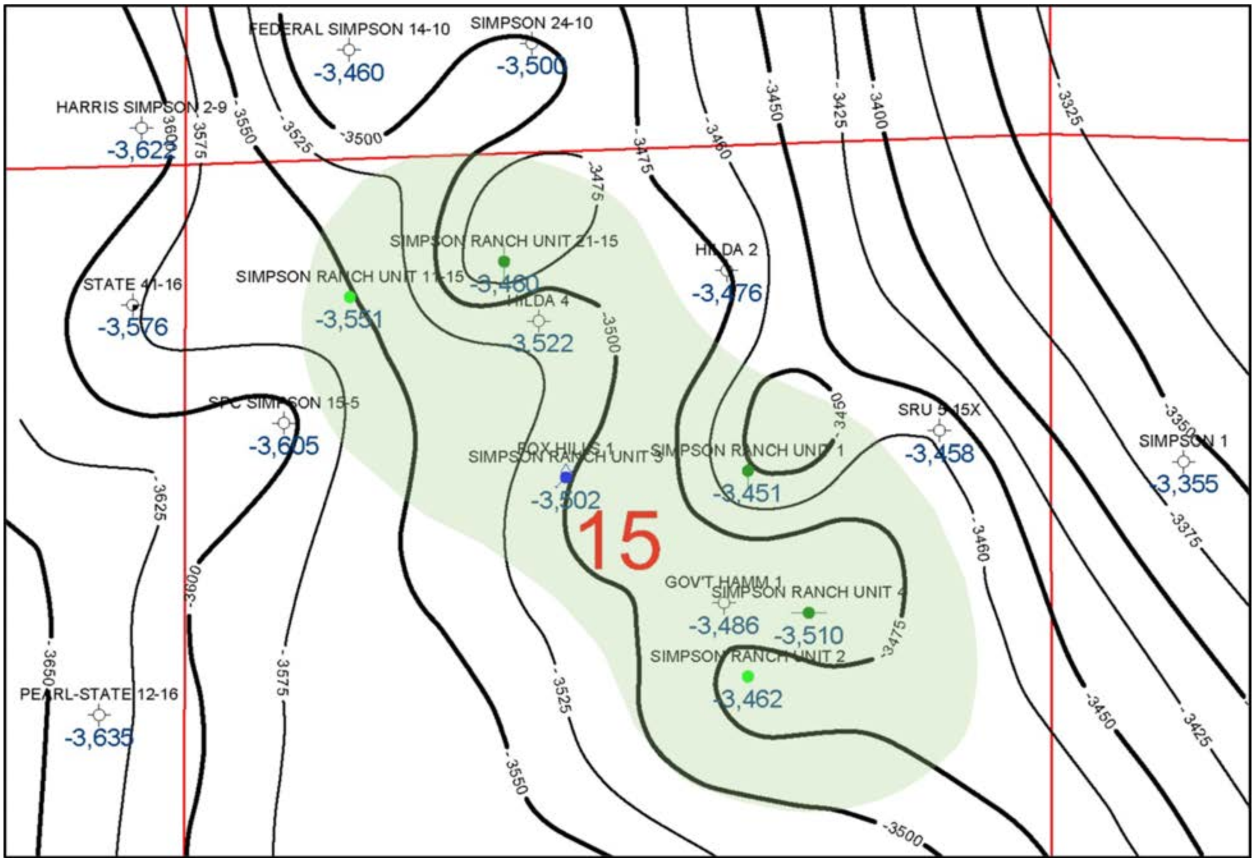

Figure 18. Base map of Simpson Ranch Field (T51N- R69W), Campbell County, Wyoming. Contours are subsea values on the top of the Minnelusa.

Polymer was injected in the field for four-and-a-half years using a total of 2,500 pounds of cationic polymer, 61,700 pounds of anionic polymer, and 74,500 pounds of aluminum citrate. In their 1984 report on the field, Mack and Duvall noted that chemical injection was a little over 25 percent of the pore volume and the chemical cost per incremental barrel of oil recovered was $3.86.

Based on production curve analysis, incremental oil production due to the polymer injection was ultimately almost 125,000 barrels (Figure 19). Assuming a total chemical cost of $1 per barrel injected, the chemical cost per incremental barrel of oil produced amounted to about $5.16.

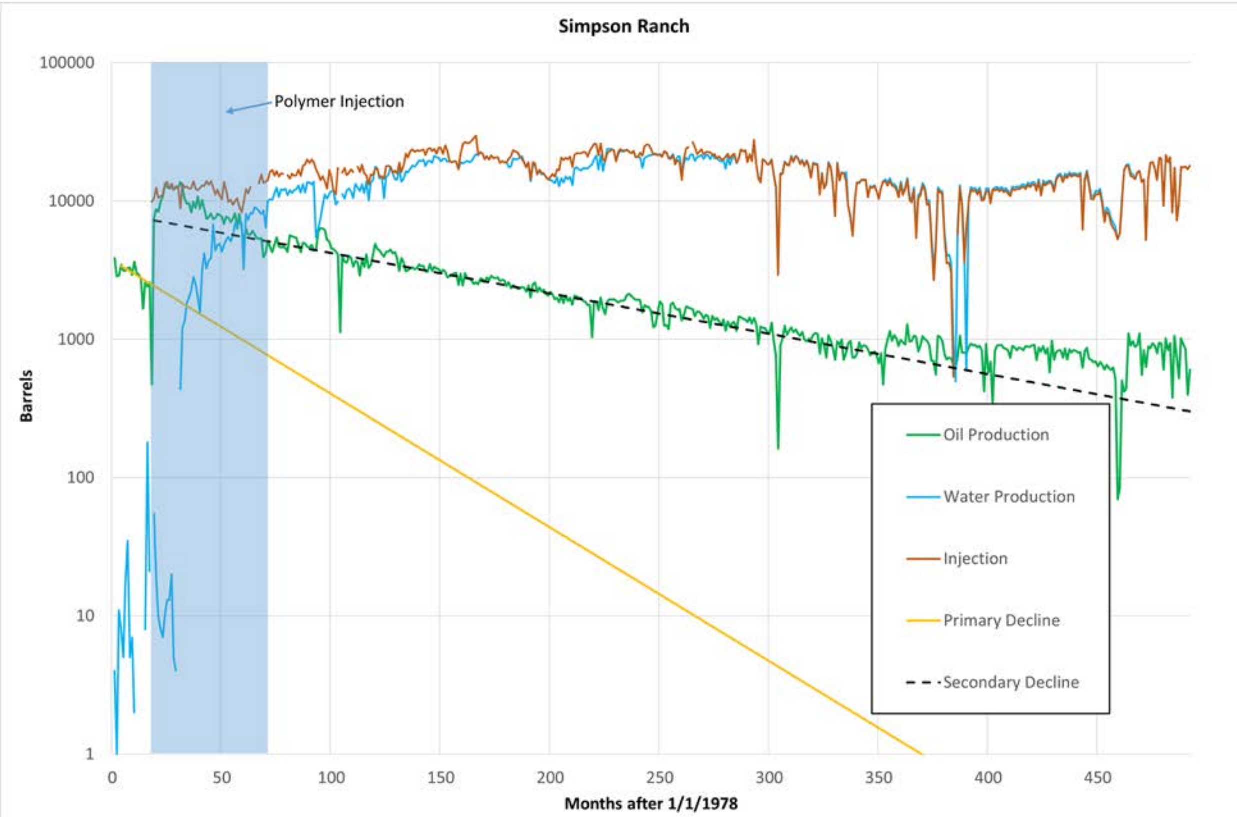

Figure 19. Production graph for Simpson Ranch Field, Campbell County, Wyoming.

Stewart Field: Discovered in 1965, Stewart Field (T50 & 51N-R69W, Campbell County, Wyoming) has produced 16.4 million barrels of oil from the Minnelusa Formation (Figure 20). One well in the field produces from the Muddy Formation, but it was completed long after the polymer flood was administered to the Minnelusa so its contribution to the overall productive trend was not deemed significant enough to alter the evaluation of the polymer flood in the Minnelusa.

The reservoir in this field exhibits extreme permeability variability and has a mobility ratio of 11 (Mack, 1978). Due to these conditions, anionic polymer was injected starting in 1972. A total polymer treatment of 1,200,000 pounds was completed in 1977 and resulted in incremental oil recovery of about 3,480,000 barrels (Mack, 1978), making it an economical flood. Since there are no readily available production and injection data prior to 1978 from the WOGCC, and since the polymer treatment was initiated prior to that date, any further assessment of the polymer treatment in this field is beyond the scope of this paper.

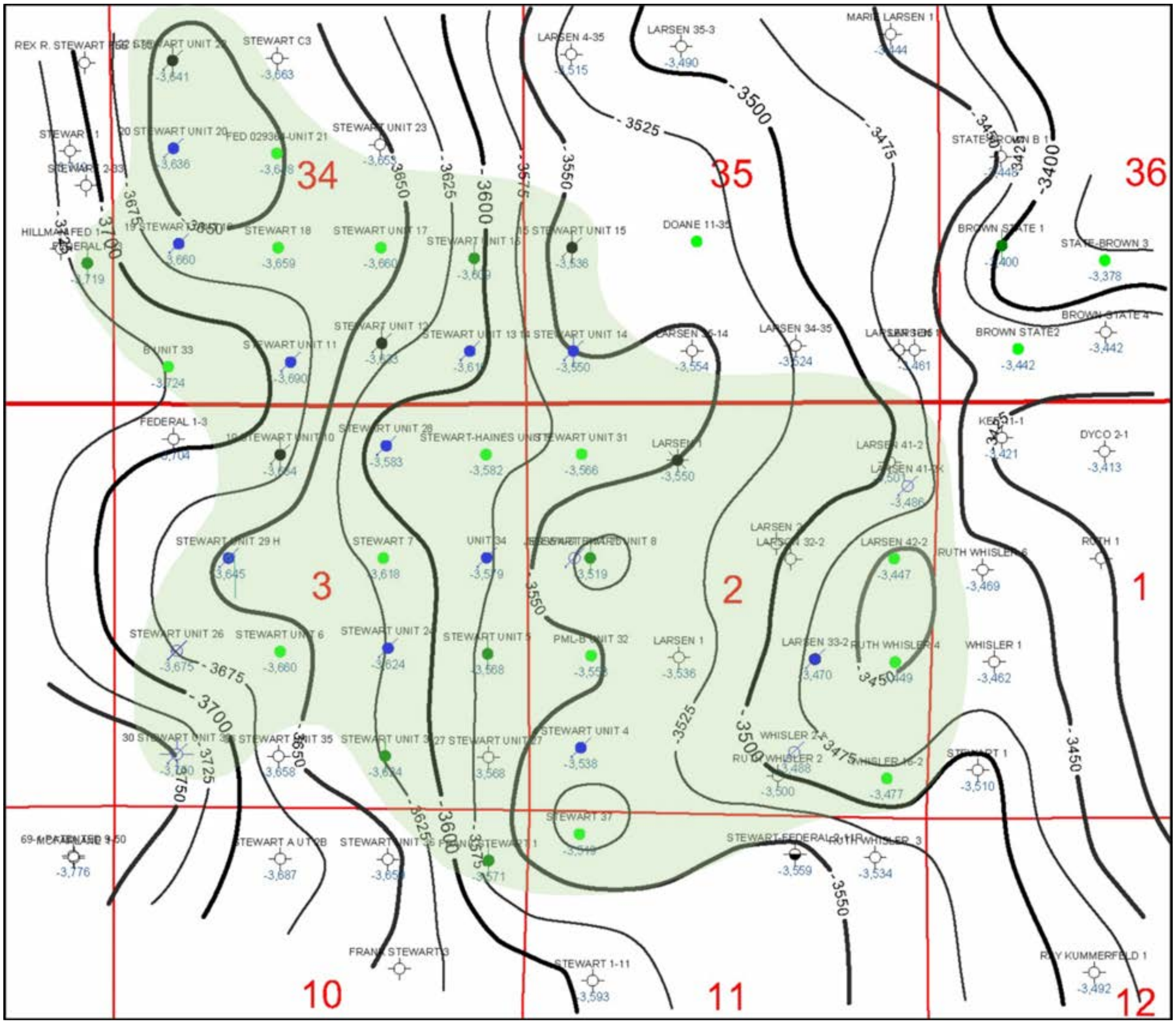

Figure 20. Base map of Stewart Field (T50 & 51N- R69W), Campbell County, Wyoming. Contours are subsea values on the top of the Minnelusa.

Evaluation of Remaining Polymer Floods Based on Production Curves

Production graphs for the remaining fifteen Minnelusa fields that appear in Table 1 are presented in the appendix of this report. All production and injection data are from the WOGCC. Apparently, there are no published articles describing the details of the polymer floods in these fields which could provide insights regarding the results of the floods. Without specific input from operators or companies overseeing the polymer floods, precise assessments of these floods cannot be made. Through reasonable assumptions, valid estimations on the effectiveness of these floods can provide insights for future efforts.

As previously noted, the assumptions made for evaluating the polymer floods are: (1) that the polymer injection began at the time of any significant production increase above the apparent conventional waterflood decline rate and (2) that the total chemical costs equate to $1 per barrel of fluid injected (in 2020 dollars) during the time of the chemical flood. All injection and production data were entered on spreadsheets. Once the average conventional waterflood decline rate is established, the amount of incremental oil produced in any given month can be calculated by subtracting the amount of oil that would have been produced at the average secondary decline rate from the total oil produced. Estimated chemical costs per barrel of incremental oil recovered are calculated by dividing calculated chemical costs by the incremental oil produced.

Conclusion

Minnelusa polymer floods have proven successful but are not a panacea. Based on interpretations presented in this report, and as illustrated in Table 1, the estimated chemical costs per barrel of incremental oil recovered vary from $1.14 to $16.82. Using these figures, two-thirds (67%) of the polymer floods examined in this report had costs under $10 per incremental barrel of oil produced. Fifty percent (50%) exhibited chemical costs under $5 per incremental barrel of oil produced.

This range in costs is due to a variety of factors, chief among them whether the flood was designed properly to address the unique set of reservoir characteristics encountered. Polymer flood failures are normally due to: (1) creating high-mobility pathways by injecting water for a long period of time before commencing polymer injection, (2) injecting polymer in wells that lack geological continuity to the rest of the reservoir, (3) not injecting enough polymer, (4) using the wrong polymer (plugging the reservoir with low-quality polymer solutions or a polymer that is too large for the pore throats), (5) shear degradation of the polymer, and (6) using a biodegradable polymer such as xanthan gum without an effective biocide (Pope, 2007).

Characteristics favorable for a polymer flood are mostly present in Minnelusa reservoirs. The following conditions typically result in successful polymer floods: (1) high remaining oil saturation, (2) low waterflood residual oil saturation, (3) good permeability and porosity, (4) sufficient vertical permeability to allow polymer to induce crossflow in the reservoir and produce good geological continuity, (5) good injectivity, (6) fresh water and/or soft water, and (7) reservoir temperatures less than 220°F.

In order to maximize the potential for a successful polymer flood, an operator needs to understand the internal architecture of the target reservoir. This understanding may require obtaining data that can be used to adequately map flow units (i.e., detailed log correlations, core data, permeability profiles, injectivity tests, pulse tests, fluid levels, inter-well tracer tests, knowledge of the mineralogy in the reservoir, etc.). A thorough characterization of the reservoir is key to optimizing any recovery method.

It is important to set clear goals for a flood and to provide good technical leadership regarding how to best sweep the flow units within the reservoir. Partnering with polymer experts is key, but it is also necessary to provide enough information to the group to ensure proper polymer flood design.

Additional EOR methods can be applied after a polymer flood and the operator might keep that possibility in mind when designing a flood. High oil prices will encourage more EOR activity, but the most economical efforts will be made by those operators who have done the best job at reservoir characterization.

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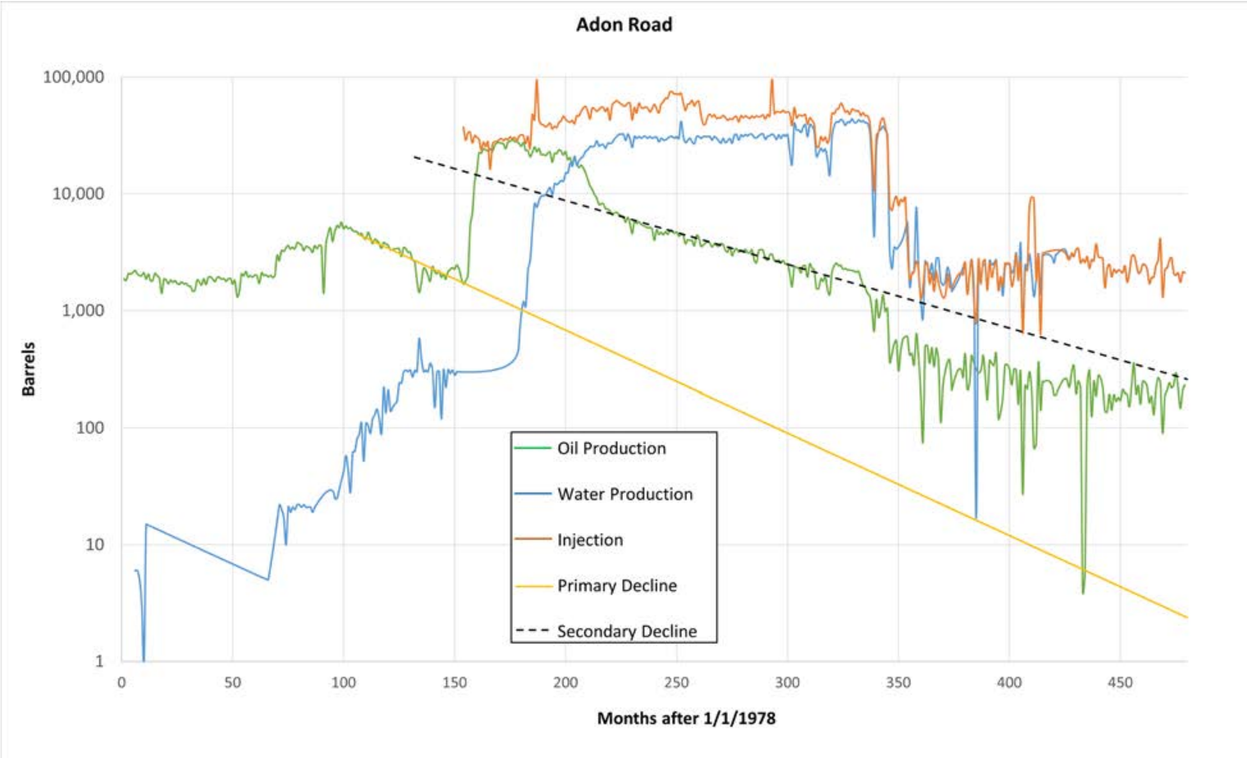
Appendix

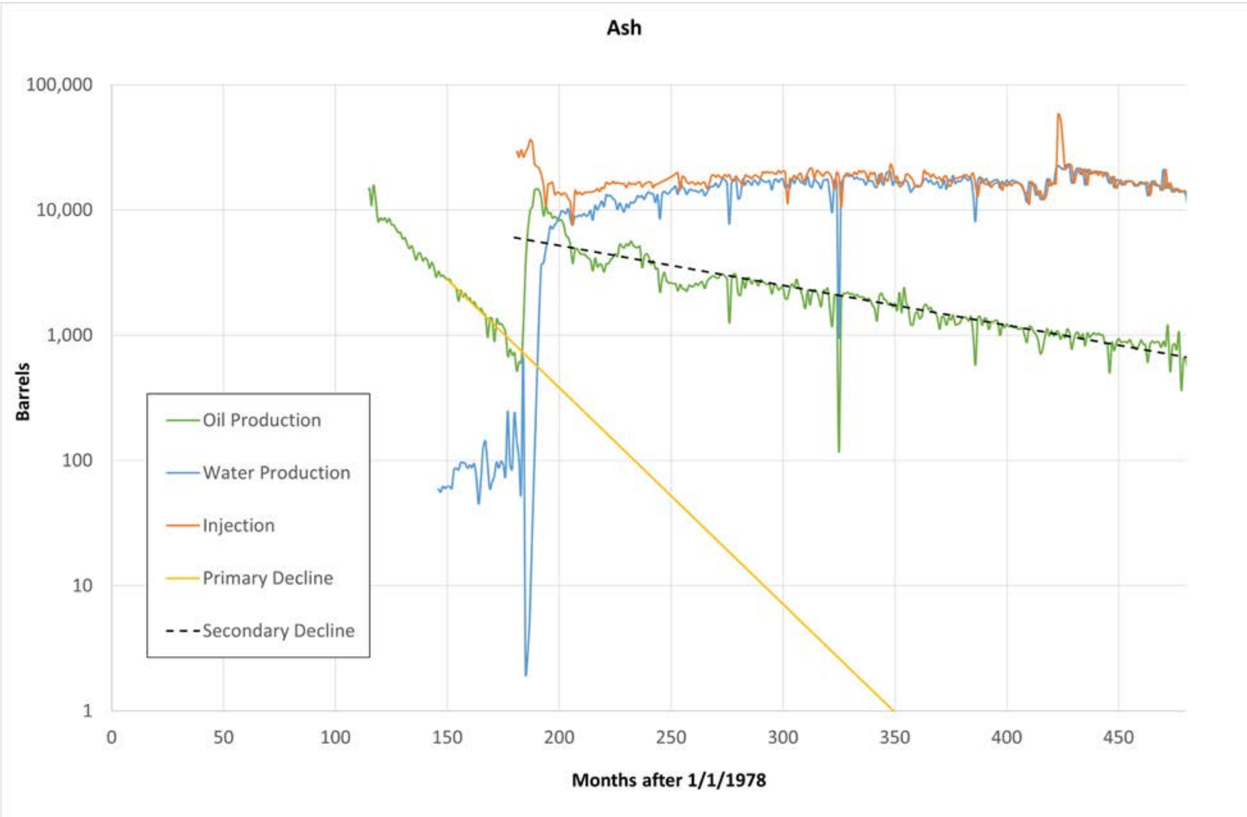


Adon Road: Polymer injection months 162 - 216.

Project Months	54
Project Injection	2,132,536 bbls
Primary Monthly Decline Rate	2.0%
Secondary Monthly Decline Rate	1.25%
Tertiary Production	617,463 bo
Chemical Cost per Incremental barrel of oil	$3.45

This polymer flood appears to have been economic.

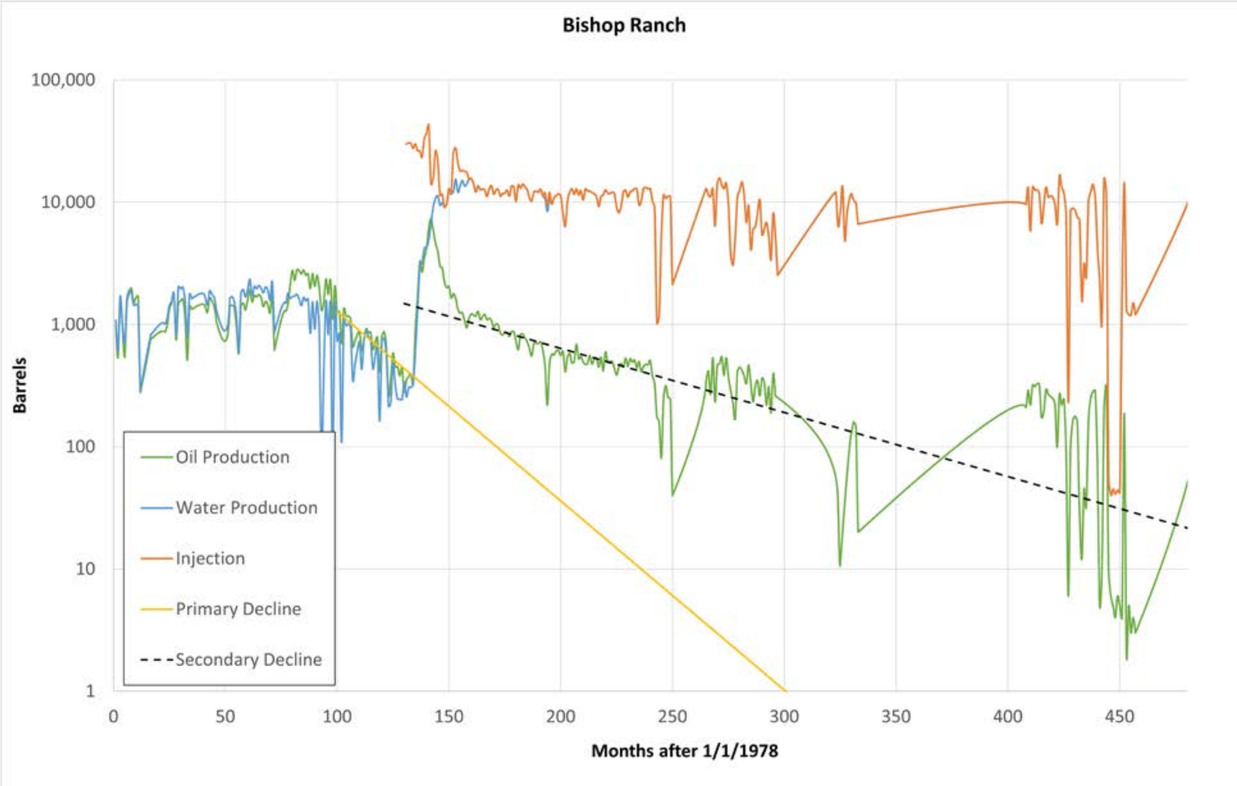
Note the production decline once the injection rate was dropped at month 346.



Ash: Polymer injection months 181 - 205.

Project Months	24
Project Injection	509,212 bbls
Primary Monthly Decline Rate	3.9%
Secondary Monthly Decline Rate	0.73%
Tertiary Production	82,059 bo
Chemical Cost per Incremental barrel of oil	$6.21

This polymer flood appears to have been economic.

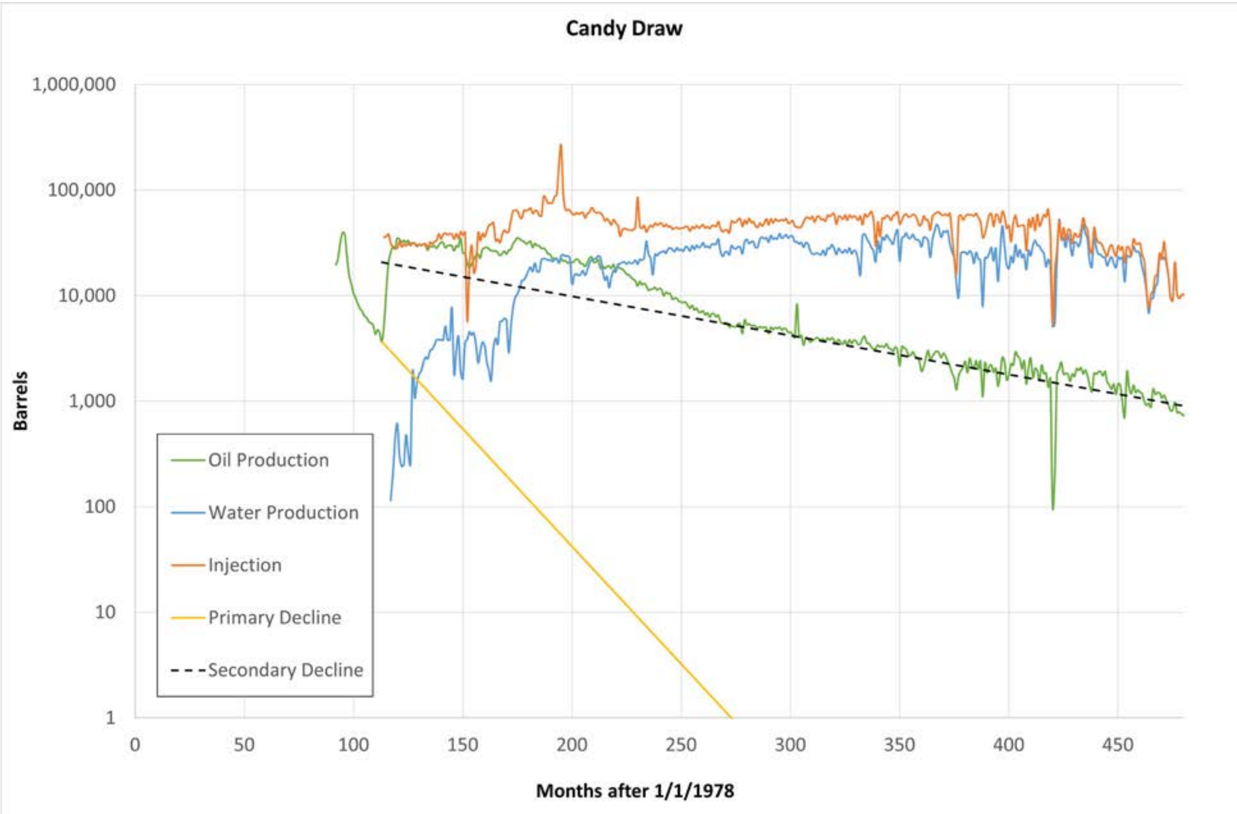


Bishop Ranch: Polymer injection months 132 - 156.

Project Months	24
Project Injection	561,056 bbls
Primary Monthly Decline Rate	3.5%
Secondary Monthly Decline Rate	1.2%
Tertiary Production	38,565 bo
Chemical Cost per Incremental barrel of oil	$14.55

This polymer flood appears to have been uneconomic.

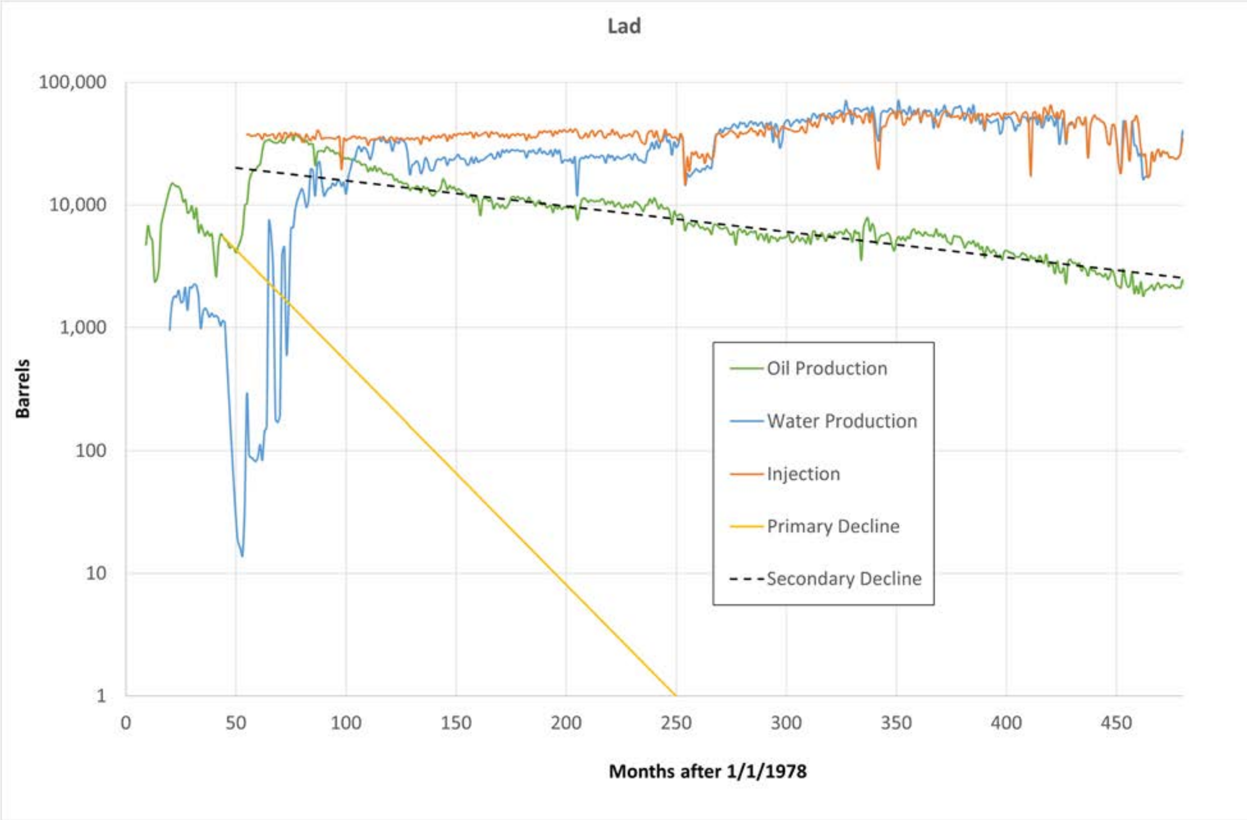
Several months had no reported production or injection. The increased production immediately after the shut-in periods are probably flush production resulting from the down time.



Candy Draw: Polymer injection months 113 - 268.

Project Months	155
Project Injection	7,561,245 bbls
Primary Monthly Decline Rate	5.0%
Secondary Monthly Decline Rate	0.85%
Tertiary Production	1,533,758 bo
Chemical Cost per Incremental barrel of oil	$4.93

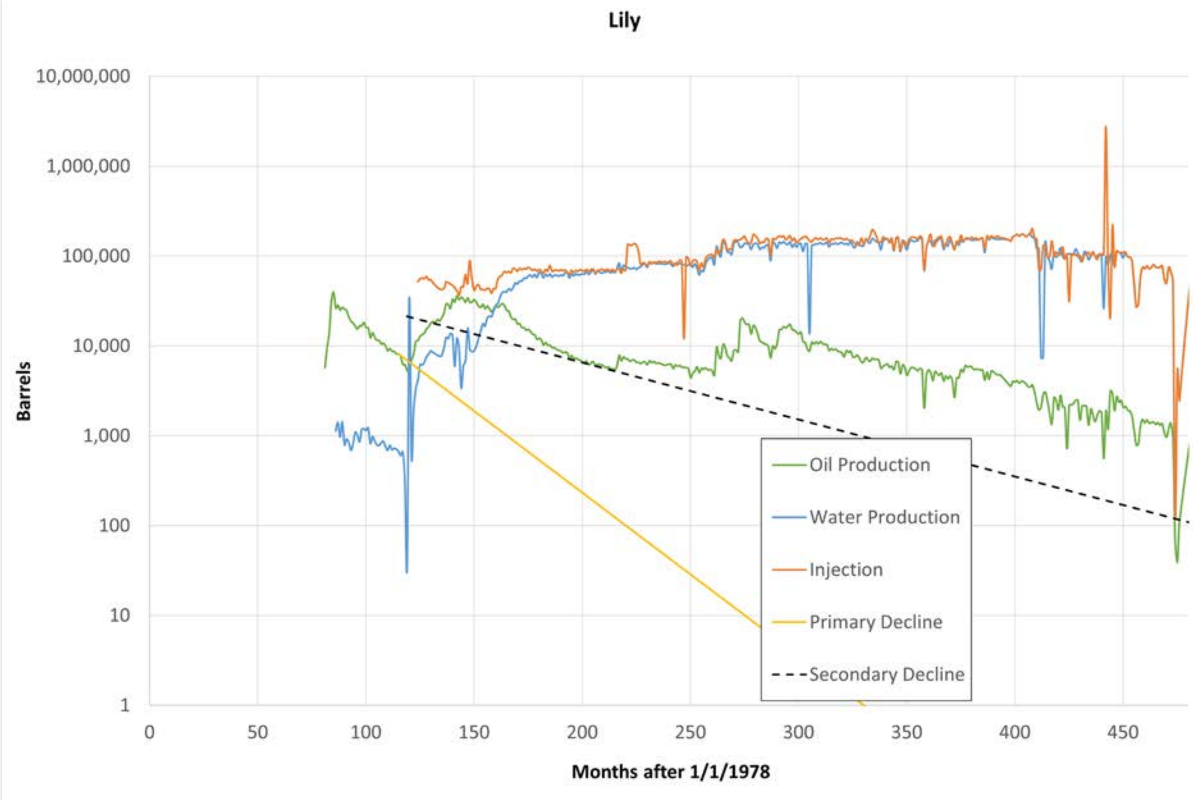
This polymer flood appears to have been economic.



Lad Field: Polymer injection months 54 - 98.

Project Months	44
Project Injection	1,582690 bbls
Primary Monthly Decline Rate	4.1%
Secondary Monthly Decline Rate	0.48%
Tertiary Production	642,367 bo
Chemical Cost per Incremental barrel of oil	$2.46

This polymer flood appears to have been economic.

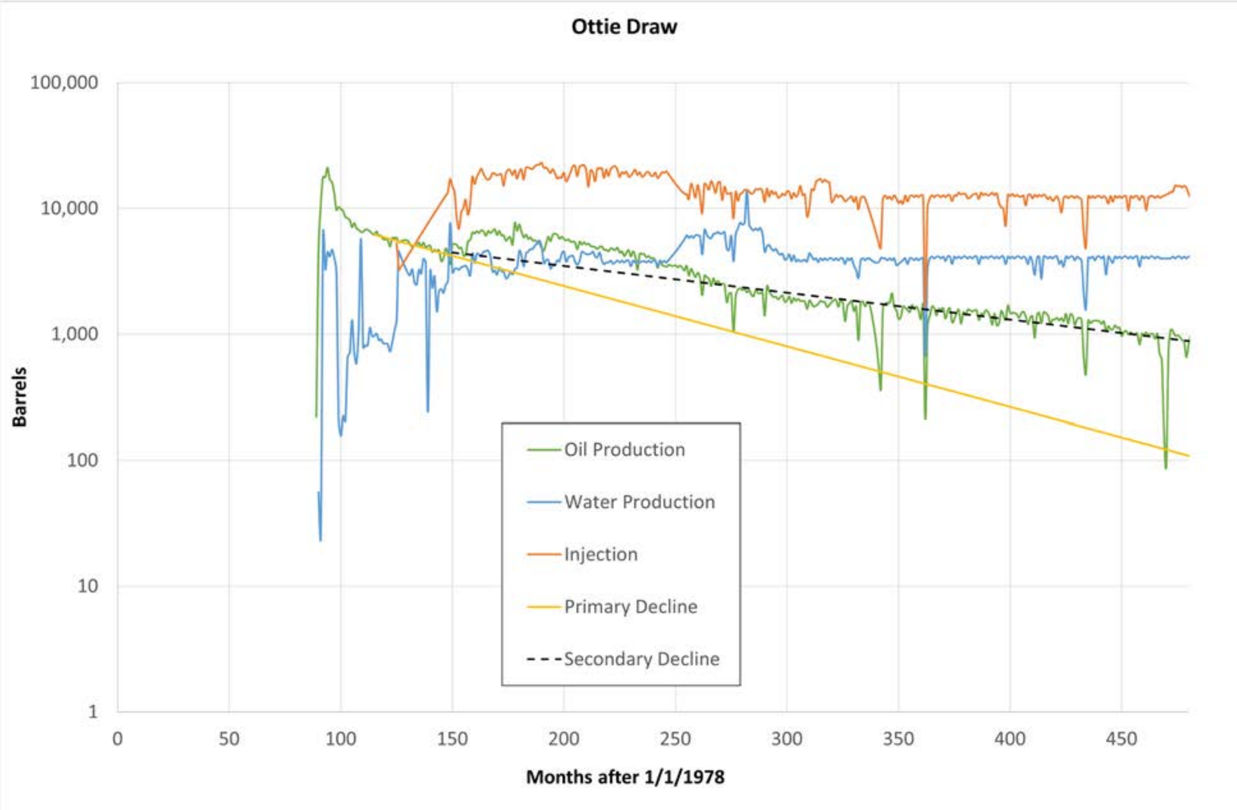


Lily: Polymer injection months 123 - 161.

Project Months	38
Project Injection	1,634,292 bbls
Primary Monthly Decline Rate	4.1%
Secondary Monthly Decline Rate	1.48%
Tertiary Production	573,162 bo
Chemical Cost per Incremental barrel of oil	$2.85

This polymer flood appears to have been economic.

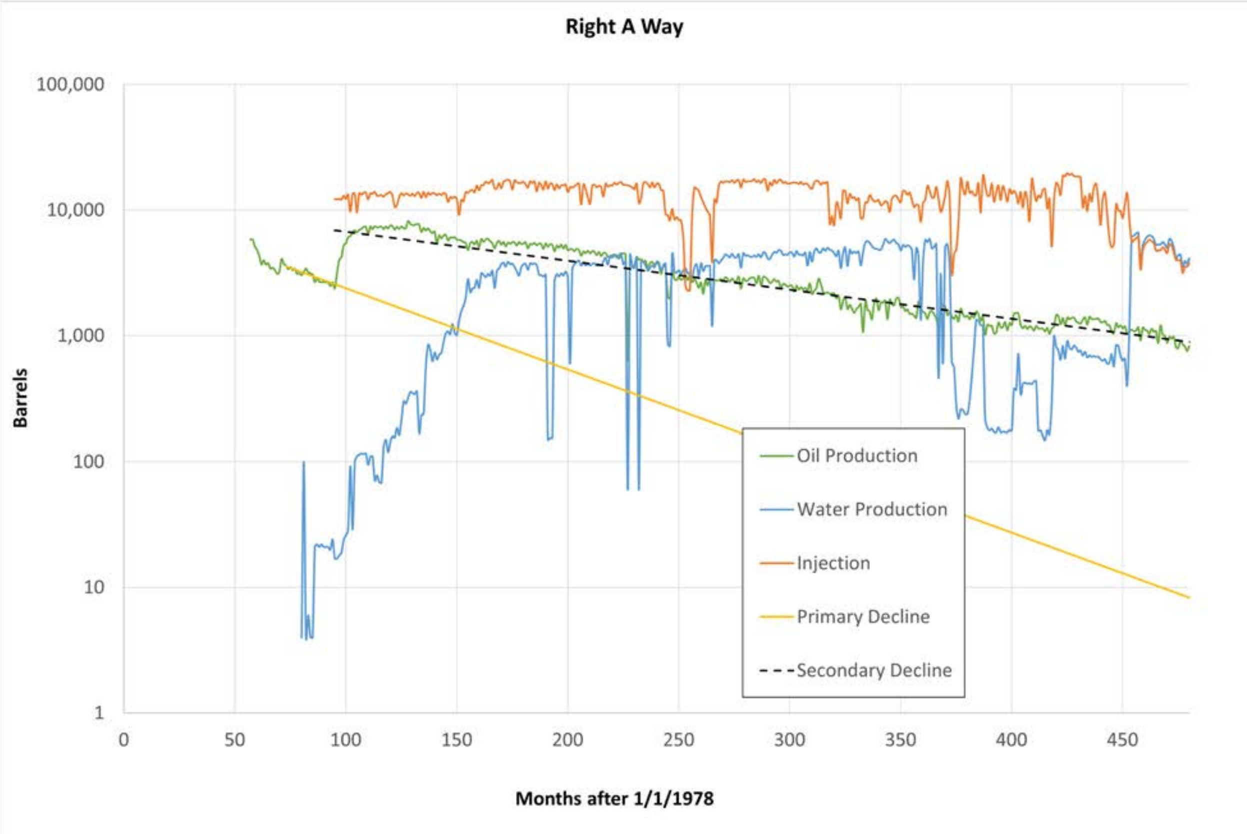
Note that increased injection rates resulted in increased production after termination of the polymer flood. There is no information regarding whether additional polymer was used or if the operator believed the previous injection of polymer continued to help the conventional water injection.



Ottie Draw: Polymer injection months 150 - 250.

Project Months	100
Project Injection	1,810,262 bbls
Primary Monthly Decline Rate	1.1%
Secondary Monthly Decline Rate	0.49%
Tertiary Production	168,858 bo
Chemical Cost per Incremental barrel of oil	$10.72

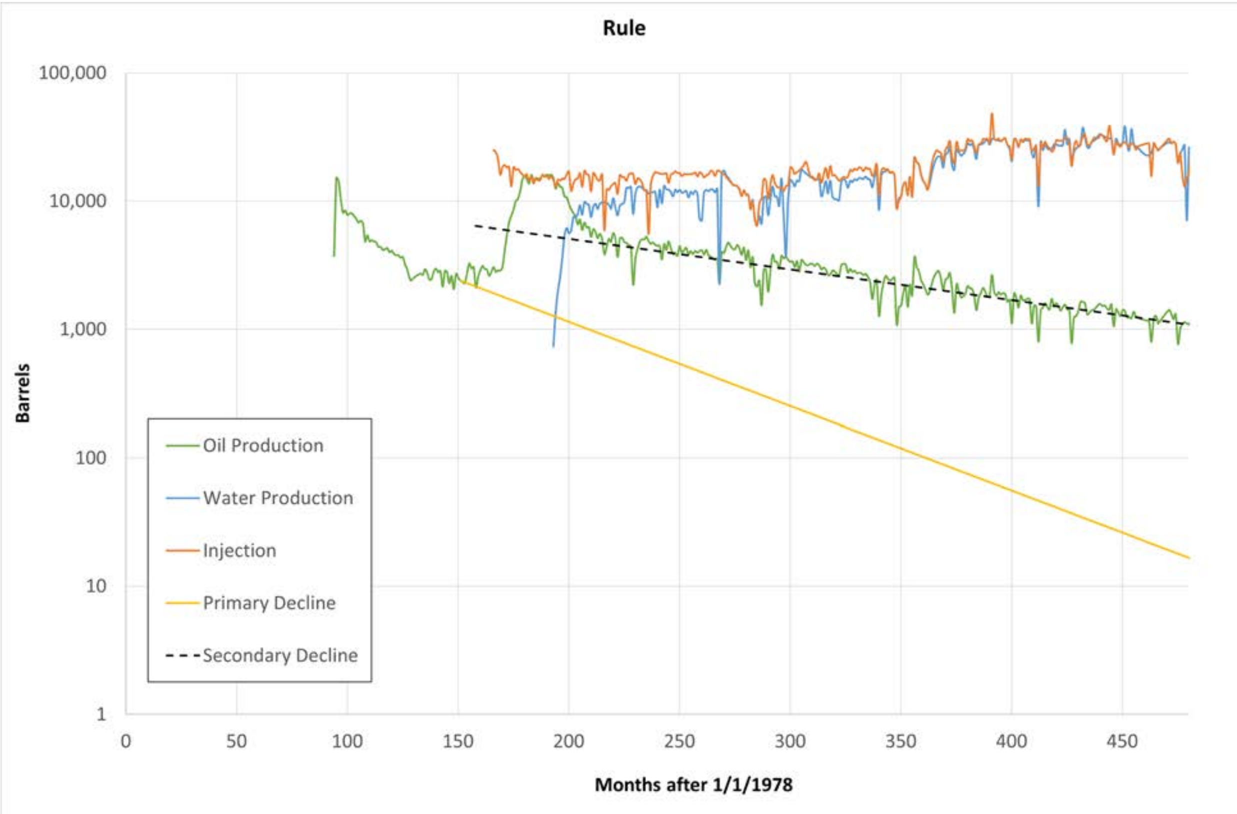
This polymer flood appears to have been marginally economic.



Right A Way: Polymer injection months 95 - 244.

Project Months	149
Project Injection	2,147,693 bbls
Primary Monthly Decline Rate	1.48%
Secondary Monthly Decline Rate	0.53%
Tertiary Production	128,1058 bo
Chemical Cost per Incremental barrel of oil	$16.77

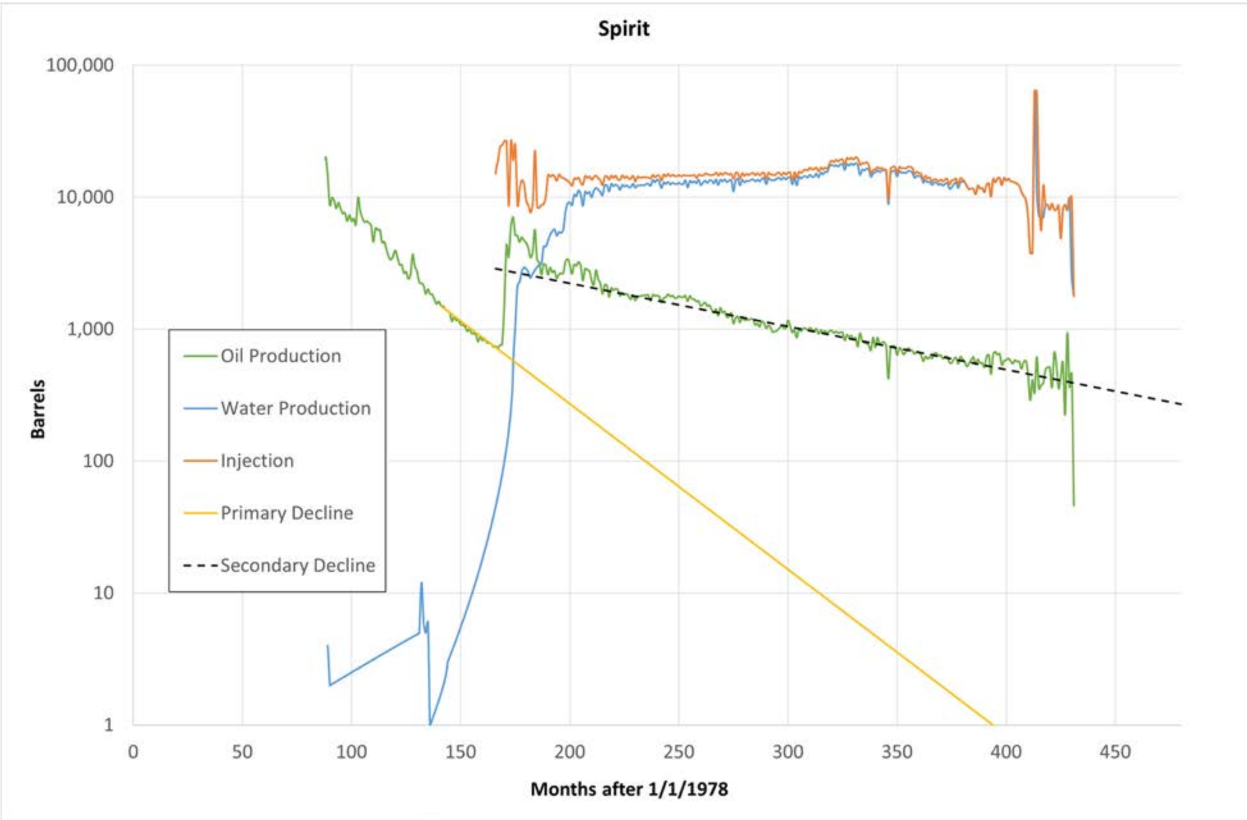
This polymer flood appears to have been uneconomic.



Rule: Polymer injection months 165 - 215.

Project Months	50
Project Injection	804,979 bbls
Primary Monthly Decline Rate	1.5%
Secondary Monthly Decline Rate	0.55%
Tertiary Production	237,666 bo
Chemical Cost per Incremental barrel of oil	$3.27

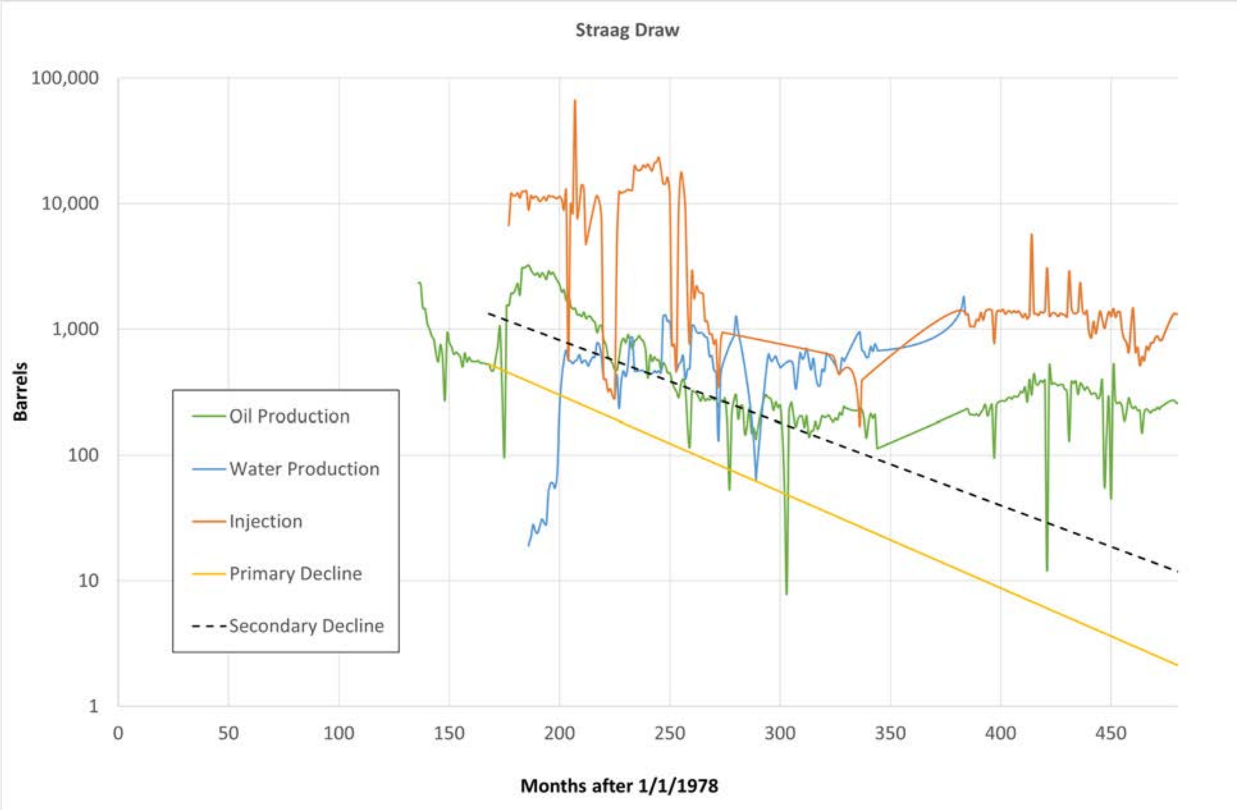
This polymer flood appears to have been economic.



Spirit: Polymer flood months 166 - 222.

Project Months	56
Project Injection	808,776 bbls
Primary Monthly Decline Rate	2.85%
Secondary Monthly Decline Rate	0.75%
Tertiary Production	48,096 bo
Chemical Cost per Incremental barrel of oil	$16.82

This polymer flood appears to have been uneconomic.

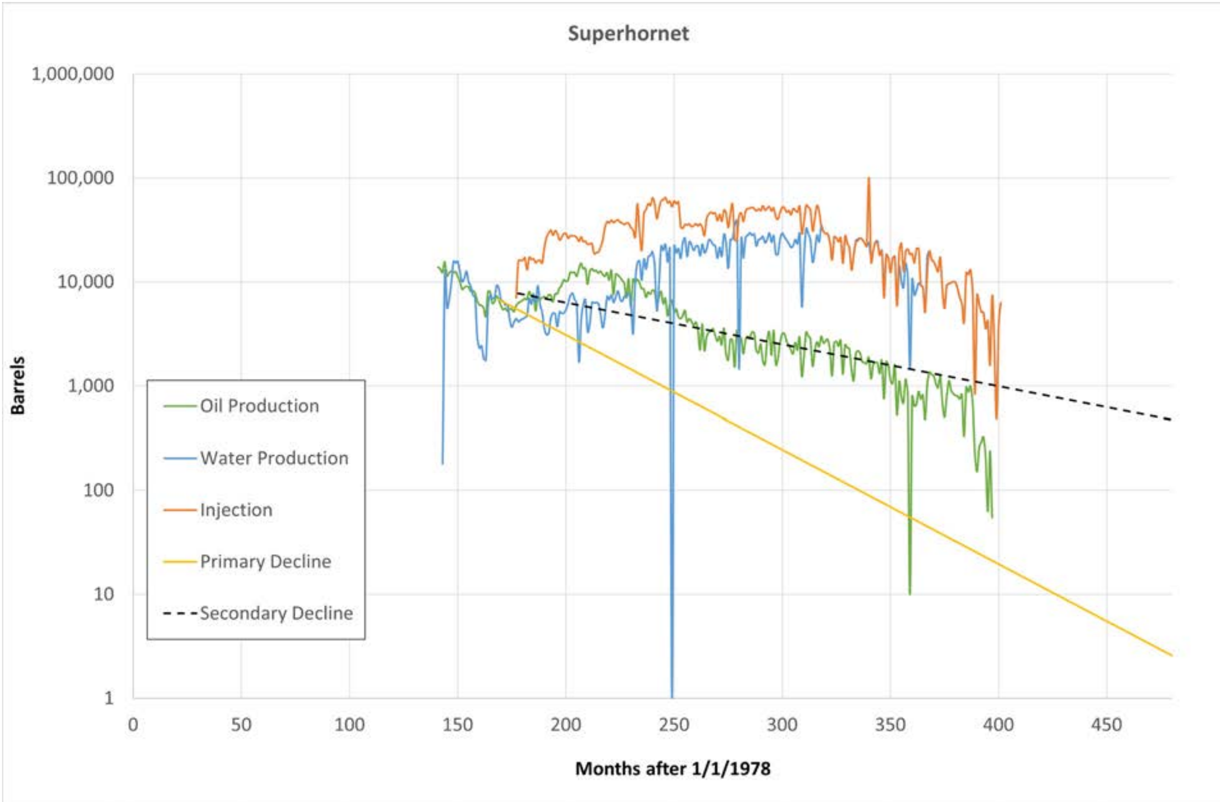


Straag Draw: Polymer injection months 176 - 221.

Project Months	45
Project Injection	504,735 bbls
Primary Monthly Decline Rate	1.75%
Secondary Monthly Decline Rate	1.5%
Tertiary Production	51,964 bo
Chemical Cost per Incremental barrel of oil	$9.71

This polymer flood appears to have been marginally economic.

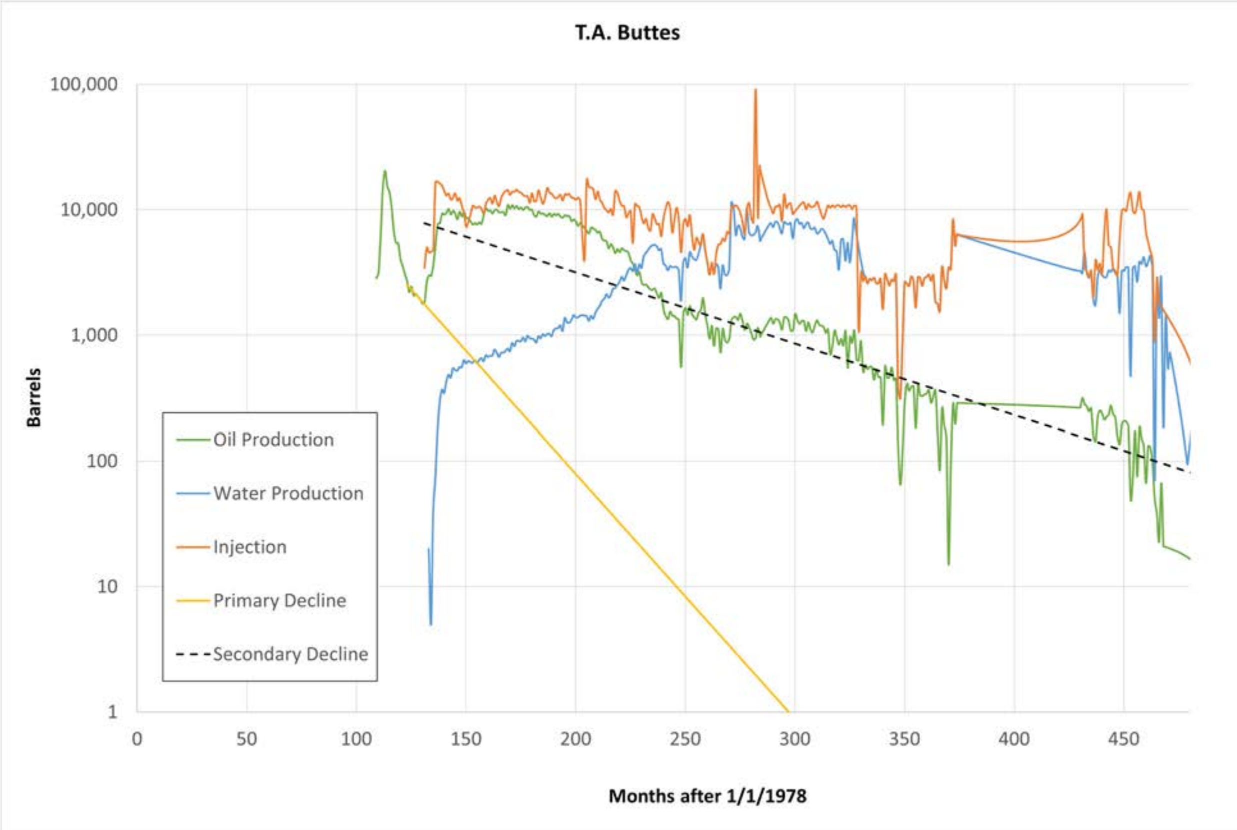
Several months had no reported production or injection. The increased production immediately after the shut-in periods are probably flush production resulting from the down time.



Superhornet: Polymer injection months 190 - 252.

Project Months	62
Project Injection	2,090,625 bbls
Primary Monthly Decline Rate	2.5%
Secondary Monthly Decline Rate	0.92%
Tertiary Production	270,274 bo
Chemical Cost per Incremental barrel of oil	$7.74

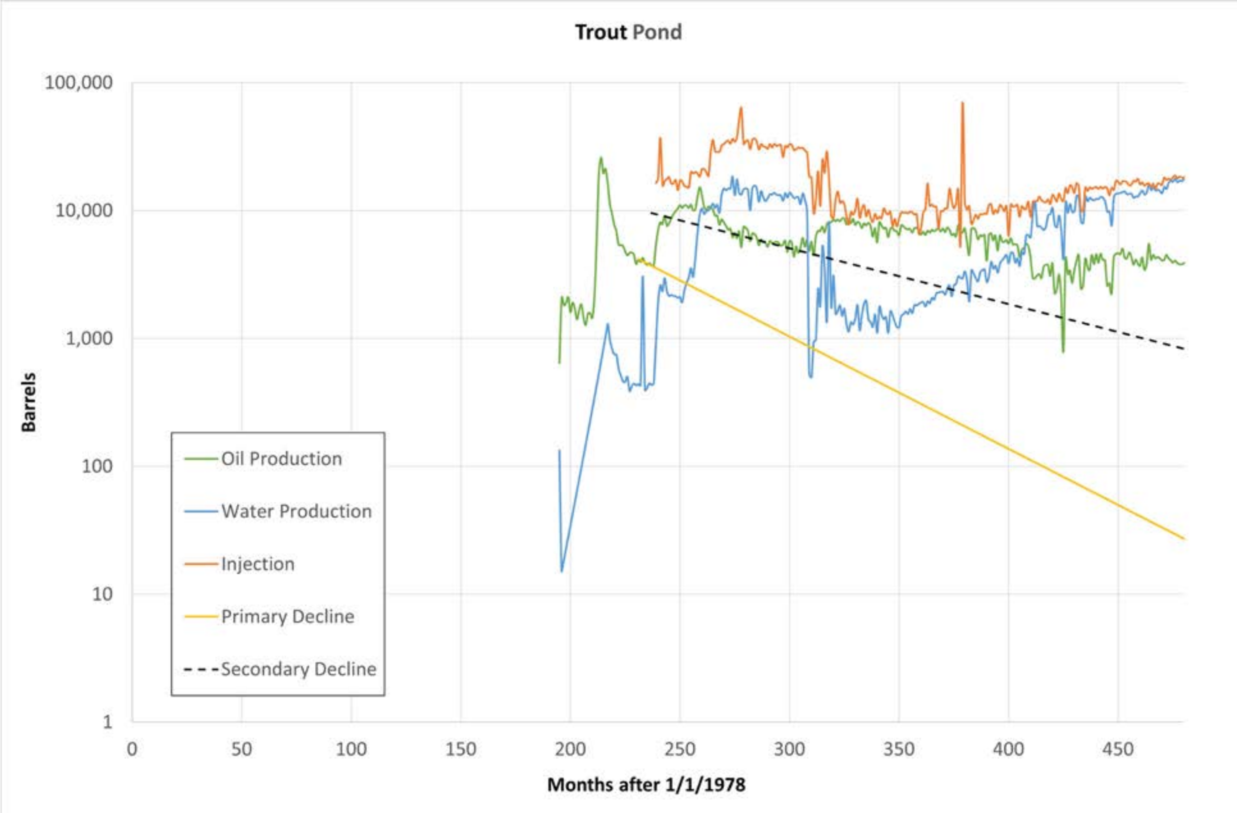
This polymer flood appears to have been economic.



T.A. Buttes: Polymer injection months 138 - 204.

Project Months	66
Project Injection	814,688 bbls
Primary Monthly Decline Rate	4.4%
Secondary Monthly Decline Rate	1.35%
Tertiary Production	347,890 bo
Chemical Cost per Incremental barrel of oil	$2.34

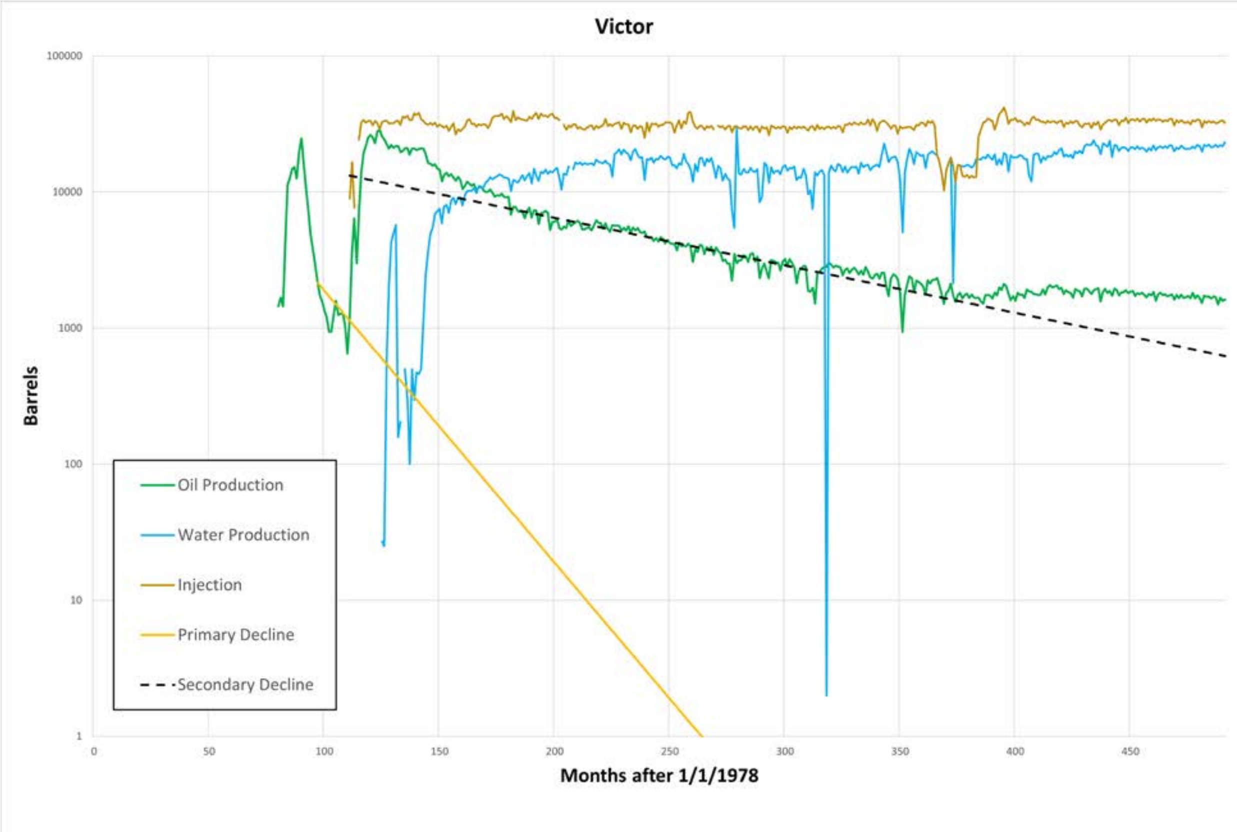
This polymer flood appears to have been economic.



Trout Pond: Polymer injection months 239 - 264.

Project Months	25
Project Injection	943,135 bbls
Primary Monthly Decline Rate	2.0%
Secondary Monthly Decline Rate	1.0%
Tertiary Production	68,326 bo
Chemical Cost per Incremental barrel of oil	$13.80

This polymer flood appears to have been uneconomic.



Victor: Polymer injection months 112 – 160.

Project Months	489
Project Injection	1,216,280 bbls
Primary Monthly Decline Rate	4.5%
Secondary Monthly Decline Rate	0.8%
Tertiary Production	380,381 bo
Chemical Cost per Incremental barrel of oil	$3.20

This polymer flood appears to have been economic.

NOTES

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