

**OPTIMIZING HORIZONTAL WELL LENGTH TO
MITIGATE INJECTIVITY LOSS DURING VISCOELASTIC
POLYMER FLOODING**

BY

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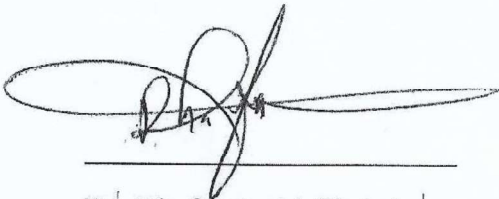
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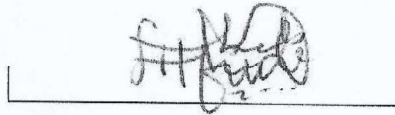
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2023

DEDICATED

To those who raised me young, encouraged me as a boy,

and raised me as a youth, to my sun and moon, my dear

Father and my dear Mother, and to my exceptionally

wonderful Siblings who supported me in my journey,

I am blessed and fortunate to have you in my life. My words cannot express my thanks and gratitude for your care, encouragement, support, and love you provided during my journey.

You are the ones who tightened this bracelet of my success, and you are the ones who pushed me forward. You deserve to be at the top of this gifting list. My Master's Thesis is dedicated to you because you are the most valuable part of my life.

-Mohammed |

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|

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LIST OF ABBREVIATIONS

A	:	Cross Sectional Area of Flow
BBL	:	Barrel
cP	:	Centipoise
Cr	:	Rock Compressibility
DX	:	1 Grid Cell Length in X-axis
DY	:	1 Grid Cell Length in Y-axis
DZ	:	1 Grid Cell Length in Z-axis
EOR	:	Enhanced Oil Recovery
ft	:	Feet
HPAM	:	Hydrolyzed Polyacrylamide
II	:	Injectivity Index
K	:	Permeability
K_X	:	Permeability in X-axis
K_Y	:	Permeability in Y-axis
K_Z	:	Permeability in Z-axis

L	:	Well Horizontal Length
m	:	meter
mD	:	Millidarcy
M_w	:	Molecular Weight
N₁	:	Polymer Shear Thinning Index
N₂	:	Polymer Shear Thickening Index
P_f	:	Formation Fracture Pressure / Formation Parting Pressure
P_i	:	Initial Reservoir Pressure
ppm	:	Parts per Million
psi	:	Pound per Square Inch
q	:	Flow Rate
S_{or}	:	Residual Oil Saturation
v	:	Velocity/Shear Rate
X	:	Reservoir Width
Y	:	Reservoir Length
Z	:	Reservoir Hight
Δp	:	Pressure Drop

μ_o	:	Oil Viscosity
μ_p	:	Polymer Viscosity
ϕ	:	Porosity

]

ABSTRACT

Full Name : Mohammed Ali AlAmeer

Thesis Title : Optimizing Horizontal Well Length to Mitigate Injectivity Loss During Viscoelastic Polymer Flooding

Major Field : Petroleum Engineering

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As per the EOR screening criteria, polymer flood can be applied in the reservoirs of varying oil viscosity, permeability etc. Polymer flooding is one of the most applied EOR methods. Polymer EOR has been mostly conducted using (hydrolyzed polyacrylamide) HPAM polymer due to its lower price, lesser susceptibility to bacterial attack, higher mobility reduction, availability in various M_w ranges etc. HPAM is a synthetic viscoelastic polymer with shear thickening characteristics; its viscosity increases as shear rate/velocity increases after the onset-rate. Biopolymers such as Xanthan gum on the other hand are viscous polymers with shear thinning characteristics. If the polymers are shear thinning alone (as is the case with xanthan gum), it is expected to have lower viscosity at a higher shear rate, meaning lower injection pressure around the well-bore, which means a higher injectivity index. On the other hand, if polymers are shear thickening at a high shear rate (as is the case with HPAM), it is expected to have higher viscosity at a high shear rate, which means higher injection pressure around the wellbore, which means a lower injectivity index. If the injection rate (and therefore injectivity index) is not reduced, then there is a risk of fracking the reservoir. Fracking is good, but it needs a proper approach. Nevertheless, horizontal well is another option. Since injectivity index is extremely important for an EOR process, steps were taken in the field (Pelican Lake field in Canada, Matzen field in Austria, and

Daqing field in China) to mitigate injectivity issues by drilling horizontal wells or inducing fracturing. The larger the horizontal well length, the fluids are going to experience low velocity (shear rate), and thereby it can avoid the shear thickening regime. However, lengthy horizontal wells are expensive and may abolish the viscoelastic effects that might have positive influence on Sor reduction. How does the rheology of the injected HPAM influence the required horizontal well-length so that one can have a comparable injectivity that a base-case xanthan gum injection can provide in the light oil, medium viscosity, heavy oil reservoir of differing permeability. This research aims to study the effects of horizontal well length requirement with regard to different shear thickening index of injected polymers, polymer viscosity, oil viscosity, and permeability on the injectivity of the well to develop a model that determine the optimum required horizontal well length to mitigate the injectivity issues of polymer floods in various reservoirs. According to the results, the horizontal well length affected the injectivity index of the polymer, removing the negative aspects of viscoelasticity and giving comparable injectivity to viscous polymers with vertical injectors. Further, the required horizontal length increases as the polymer elasticity (shear thickening index), polymer viscosity, and oil viscosity increase while it decreases when the permeability increases. However very low polymer viscosity, the polymer viscoelasticity effect on horizontal well length is insignificant. The developed correlations at the end of this work help estimating the optimum required horizontal well length required for the three studied cases using staggered line injection pattern. It is worth noting that the method proposed in this work can be followed for other field cases with different parameters, characteristics, and injection patterns to get a representative correlation for optimizing the injector horizontal well length. |

ملخص الرسالة

الاسم الكامل: محمد علي الأمير

عنوان الرسالة: تحسين طول البئر الأفقي للتخفيف من فقد الحقن أثناء غمر البوليمر اللزج مرن

التخصص: هندسة البترول

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وفقاً لمعايير فحص الاستخلاص المعزز للنفط، يمكن تطبيق غمر البوليمر في المكامن ذات اللزوجة والنفاذية المتغيرة وما إلى ذلك. يعتبر غمر البوليمر أحد أكثر طرق الاستخلاص المعزز للنفط (EOR) تطبيقاً. تم إجراء الاستخلاص المعزز للنفط للبوليمر في الغالب باستخدام بوليمر بولي أكريلاميد متحلل بالماء (HPAM) بسبب انخفاض سعره، وقابلية أقل للهجوم البكتيري، وتقليل حركية أعلى، وتوافره في نطاقات أوزان جزيئية (M_w) مختلفة وما إلى ذلك. البوليمر بولي أكريلاميد متحلل بالماء (HPAM) عبارة عن بوليمر صناعي لزج مرن يمتلك خصائص سماكة القص؛ حيث تزداد لزوجته مع زيادة معدل القص/السرعة بعد معدل البداية. من ناحية أخرى، فإن البوليمرات الحيوية مثل صمغ الزانثان (Xanthan Gum) عبارة عن بوليمرات لزجة ذات خصائص ترقق القص. إذا كانت البوليمرات تمتلك أو تظهر خصائص ترقق القص بمفردها (كما هو الحال مع صمغ الزانثان)، فمن المتوقع أن يكون لها لزوجة أقل بمعدل قص أعلى، مما يعني انخفاض ضغط الحقن حول تجويف البئر، مما يعني ارتفاع مؤشر الحقن. من ناحية أخرى، إذا كانت البوليمرات تتكاثف بمعدل قص مرتفع (كما هو الحال مع HPAM)، فمن المتوقع أن يكون لها لزوجة أعلى بمعدل قص مرتفع، مما يعني ارتفاع ضغط الحقن حول حفرة البئر، مما يعني انخفاض مؤشر الحقن. إذا لم يتم تقليل معدل الحقن (وبالتالي مؤشر الحقن)، فهناك خطر تكسير الخزان. التكسير الهيدروليكي جيد، لكنه يحتاج إلى نهج مناسب. ومع ذلك، فإن البئر الأفقي هو خيار آخر. نظراً لأن مؤشر الحقن مهم للغاية لعملية الاستخلاص المعزز للنفط، فقد تم اتخاذ خطوات في هذا المجال (حقل بحيرة البجع في كندا، وحقل ماتزن في النمسا، وحقل داكينغ في الصين) للتخفيف من مشكلات الحقن عن طريق حفر الآبار الأفقية أو إحداث كسر. كلما زاد طول البئر الأفقي، ستواجه السوائل سرعة منخفضة (معدل القص)، وبالتالي يمكنها تجنب نظام سماكة القص. ومع ذلك، فإن الآبار الأفقية الطويلة باهظة الثمن وقد تلغي التأثيرات اللزجة المرنة التي قد يكون لها تأثير إيجابي على تخفيض تشبع الزيت

غير القابل للاختزال (Sor). كيف تؤثر الانسيابية الخاصة بـ HPAM المحقون على طول البئر الأفقي المطلوب بحيث يمكن للمرء الحصول على مقدار مقارب من الحقن الذي يمكن أن يوفره حقن صمغ الزانثان الأساسي في الزيت الخفيف والزوجة المتوسطة ومكمن الزيت الثقيل ذو نفاذية مختلفة. يهدف هذا البحث إلى دراسة آثار متطلبات طول البئر الأفقي فيما يتعلق بمؤشر سماكة القص المختلفة للبوليمرات المحقونة ولزوجة البوليمر ولزوجة الزيت والنفاذية على حقنة البئر لتطوير نموذج يحدد الطول الأمثل المطلوب للبئر الأفقي للتخفيف من مشاكل الحقن المقرونة مع عمر البوليمر في المكامن المختلفة. وفقًا للنتائج، أثر طول البئر الأفقي على مؤشر الحقن للبوليمر، مما أدى إلى إزالة الجوانب السلبية لمرونة اللزوجة وإعطاء حقنة مماثلة للبوليمرات اللزجة في آبار الحقن الرأسية. علاوة على ذلك، يزيد الطول الأفقي المطلوب مع زيادة مرونة البوليمر (مؤشر سماكة القص) ولزوجة البوليمر ولزوجة الزيت بينما تتناقص عندما تزداد النفاذية. عند لزوجة البوليمر المنخفضة جدًا، يكون تأثير مرونة لزوجة البوليمر على طول البئر الأفقي ضئيلاً. تساعد نماذج الارتباطات المطورة في نهاية هذا العمل في تقدير الطول الأمثل المطلوب للبئر الأفقي المطلوب للحالات الثلاث المدروسة باستخدام نمط حقن الخط المتعرج. تجدر الإشارة إلى أن الطريقة المقترحة في هذا العمل يمكن اتباعها للحالات الميدانية الأخرى ذات المعاملات والخصائص وأنماط الحقن المختلفة للحصول على ارتباط تمثيلي لتحسين طول البئر الأفقي للحاقن. |

CHAPTER 1

INTRODUCTION

1.1. Polymer Flood Injectivity Issues

Global energy demand is on continuous increase due to population growth and economy thrive. Most of the mature oil fields are characterized by high water cut with large volumes of unswept oil left behind. Polymer flooding is implemented to improve the sweep efficiency and enhance the recovery from such fields to meet the world demand for oil. However, the impact of shear rate on the polymer solution viscosity is a challenge through polymer flooding that is associated with injectivity issues (Abbasi et al., 2017). The well injectivity decreases over time due to the changes of the polymer solution viscosity during the flooding process. HPAM is the most commonly used EOR polymer and it exhibit viscoelastic characteristics. **Figure 1.1** illustrates the viscosity behavior of viscoelastic polymer solution against shear rate. As the shear rate increases to the shear thickening regime, the viscosity of the polymer solution increases leading to a higher pressure drop and consequently injectivity decline (Salmo et al., 2021).

Glasbergen et al. (2015) point out some suggested proposals to mitigate the injectivity decline issues accompanied with viscoelastic polymer flooding including fracturing injection and altering polymer rheology such as reducing the molecular and decreasing the concentration. Injecting polymer under fracturing conditions helps to

initiate polymer flooding above the formation fracturing gradient. The induced fractures support the incremental increase of injectivity.

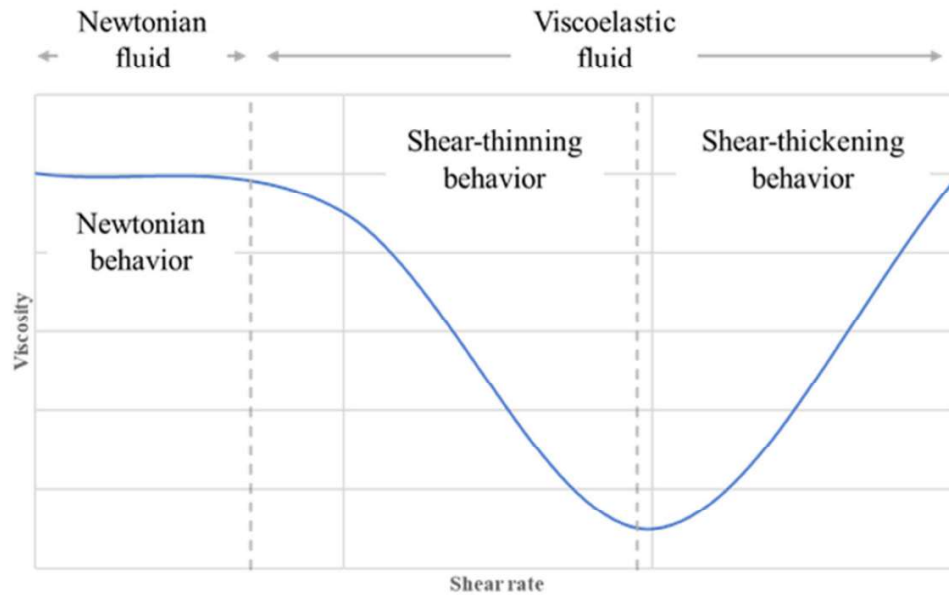


Figure 1.1: Viscoelastic polymer viscosity against shear rate. As shear rate increases, polymer viscosity increases when it reaches shear thickening region (Salmo et al., 2021)

In addition to the prementioned mitigation actions, injection through horizontal wells would improve the sweep efficiency and improve injectivity (Taber & Seright, 1992). Depending on the reservoir dimensions, the staggered line injection pattern recovers more oil than the five-spot pattern, especially in cuboid reservoirs due to piston like displacement which improves the sweep efficiency. The horizontal section provides additional surface area for displacing the polymer solution and thus less pressure drop and consequently improved injectivity. Thus, the selection of optimum horizontal length is important.

1.2. Problem Description

Polymer flooding is one of the most widely applied enhanced oil recovery (EOR) methods. During polymer flood, the polymer powders are added to the injection water to make it more viscous. The injected polymer solutions propagate with reduced mobility, accelerates the oil recovery, and improves the sweep efficiency. Hydrolyzed polyacrylamide (HPAM) is the widely used polymer for EOR applications. HPAM polymers are viscoelastic in nature, and they tend to exhibit shear thickening phenomenon (Azad & Trivedi, 2019). This phenomenon causes an increase in the viscosity with respect to the increase in the shear/flux rate. The high viscosity leads to high injection pressure which therefore reduces the injectivity for the floods carried out using vertical wells. This is because vertical wells are exposing the fluid to smaller area which means for the given injection rate, injection velocity will be on the higher side. While injectivity loss is detrimental, viscoelasticity could lead to higher S_{or} reduction in favorable conditions of high pressure and/or high rate (Azad & Trivedi, 2020; Clarke et al., 2016; Demin et al., 2011; Erincik et al., 2018). In recent times especially for heavy-oil polymer flood, the horizontal wells are employed to increase the flow-area so that it could reduce the flux-rate to avoid the high pressure caused by shear-thickening around the injectors (Delamaide et al., 2014). Heavy oil reservoirs require high polymer viscosity that can be achieved through thickening behavior due to viscoelasticity to sustain a favorable mobility ratio that could displace the heavy oil. Besides that, heavy oil itself offers more resistance to the flow of polymer; thereby resulting in a higher pressure drop and reduced injectivity. To mitigate them, horizontal wells are employed. The viscoelastic behavior of polymer floods depends on the reservoir fluids and rock properties. The required horizontal length would depend

on the polymer solution viscoelasticity. High thickening behavior requires lengthy horizontal wells to get rid of the negative viscoelastic effect. For low shear thickening polymer systems, the needed horizontal length to overcome the high injection pressure may be less. The injection pressure would increase with increasing thickening index, and consequently the longer the horizontal length.

In this work, we want to optimize the horizontal length by taking three major cases into consideration:

- 1- **Case 1**: Considering injectivity alone in which the horizontal length would be optimized to give similar or slightly higher injectivity than the viscous polymer injection without paying much attention to total recovery and economics.
- 2- **Case 2**: Considering injectivity and overall recovery, and hence the economics, without considering the viscoelastic effect.
- 3- **Case 3**: Considering viscoelastic effect on S_{or} reduction. However, this case was dropped for the time being and will be considered in future enhancement of this work since no simulator can precisely honor viscoelastic effect on S_{or} reduction and predict the microscopic recovery.

1.3. Research Objectives

This research seeks to find an answer for the optimum horizontal well-length for polymer injectors by simulating light, medium and heavy oil polymer flooding. Polymer flooding is simulated using viscous polymers and viscoelastic polymers whose shear thickening index ranges from low, to medium, to high and to very high. Examining horizontal polymer flooding (with various shear-thickening index) of various length aims

to find what must be horizontal well-length so that one can get a comparable injectivity with the vertical-well polymer flooding carried out at unfractured conditions using zero shear thickening viscous polymer (purely shear thinning polymer) in different oil reservoirs. In summary, the investigated items will be as follows:

1. Optimizing the horizontal well length based on the polymer solution viscoelasticity so that one can get comparable/slightly higher injectivity that can be generated by the viscous polymer solutions.
2. Determining the additional required horizontal well length to mitigate the injectivity loss for three representative field conditions. Those three field conditions have varied polymer-oil viscosity ratio: 1) highly unfavorable such as in Pelican Lake, 30 cP polymer to displace 3000 cP oil 2) favorable such as Matzen, 10 cP polymer to displace 19 cP oil 3) highly favorable such as in Daqing, 300 cP polymer to displace 10 cP oil (Seright, 2017). We also further varied the polymer viscosity for each case to cover a wide range of polymer system design in the correlation model. These polymer viscosities are as follows: 1) Matzen field with 2.5 cP, 10 cP, and 100 cP 2) Pelican Lake field with 3 cP and 30 cP only due to high oil viscosity 3) Daqing field with 3 cP, 30 cP, and 300 cP.
3. Developing a correlation model that determines the optimum required horizontal well length to yield the optimum injectivity in three representative oil reservoir conditions characterized by different magnitudes of polymer-oil viscosity ratio and polymer viscoelasticity. The correlation model will be developed for three oil reservoir cases with different viscosity ratios. The novelty in this work is the methodology of developing correlation models for each reservoir to remove the

negative viscoelastic effect through determining the optimum required horizontal length.

CHAPTER 2

LITERATURE REVIEW

2.1. Reservoir Engineering Concept

Reservoir engineering is concerned with the application of scientific and engineering principles to maximize the economic return of the production from developed hydrocarbon reservoirs (Hyne, 1991). From this point of view, the interest in enhanced oil recovery (EOR) soared to meet the endless increasing demand for energy. What governs the applications and implementation of EOR projects is the economic constraints controlled by oil prices. Providing innovative solutions that boost the feasibility of such projects is of high importance to reservoir engineers to maximize the commercial recovery from reservoirs. In line with the provided definition, this research utilizes the scientific concept of viscoelasticity in engineering applications including finding the optimal horizontal well length to get rid of negative aspect of viscoelasticity.

2.2. Enhanced Oil Recovery

On estimate, one-third of the original oil in place is recovered by conventional production during the first phase of the reservoir life through primary and secondary recovery. The un-swept residual oil left behind is recovered via tertiary recovery methods called Enhanced Oil Recovery. Thus, EOR refers to the production of liquid hydrocarbons from mature reservoirs with declining performance using methods other than the

conventional ones which rely on the natural energy of the reservoir. Therefore, EOR techniques are more expensive and are governed by the oil price. EOR methods selection criteria depend on reservoir fluid and rock properties, but in general it implies the injection of fluids to mobilize the residual oil trapped by strong viscous and capillary forces in the reservoir rock-fluid system (Karovic-Maricic et al., 2014). EOR techniques are divided into two major categories which are methods to improve the volumetric sweep efficiency, and methods to improve microscopic recovery (Satter & Thakur, 1994). These methods include gas injection, thermal injection, chemical injection. Chemical injection is broad and has many types including polymer floods which is the area interest of interest in this work.

2.3. Polymer Flooding

Polymer flooding is an enhanced oil recovery method that is widely applied to improve the recovery of from matured field around the world. According to Torrealba & Hoteit (2019), this mechanism of this technology relies on the addition of powder polymer into the injected water to increase its viscosity which help mobilizing the un-swept oil and improve the sweep efficiency (macroscopic recovery). Over the last 50 years, polymer flooding has been recognized as an effective EOR technique implemented globally in many fields with various reservoir properties and oil viscosities as shown in **Table 2.1**. There are two major categories of polymers: viscous polymers and viscoelastic polymers, each with its own advantages and limitations.

The most successful polymer projects around the world with positive results include Pelican Lake Field in Canada (Delamaide et al., 2014), Matzen Field in Austria

(Lüftenegger et al., 2015), and Daqing Field in China (Wang et al., 2008). Those successful polymer flooding projects represent different ranges of permeability (300-1100 mD), oil viscosity (9-1650 cP), polymer viscosity (1.6-300 cP), and polymer to oil viscosity ratio (0.012-30) values. The aim of research is to develop a correlation to capture all those varying variables to estimate the required horizontal well length for the polymer injector.

Table 2.1: Reservoir and polymer data of fields with polymer flooding projects

Field	Polymer Type	μ_p (cP)	ϕ (%)	K (mD)	μ_o (cP)	Reference
Marmul, Oman	FP3630s	15	25-30	100-2000	90	(Thakuria et al., 2013)
Abu Dhabi, UAE	HPAM (ATBS)	1.2-5.5	20-30	10-1000	1	(Baloch et al., 2021)
Pelican Lake, Canada	FP3630s	13-25	28-32	300-5000	1650-15000	(Delamaide et al., 2014)
Matzen, Austria	FP3630ss	1.6-4.6	20-30	500	19	(Lüftenegger et al., 2015)
Mangala Field, India	FP3630s	15-20	15-30	5000	10-20	(Kumar et al., 2012)
Daqing, China	HPAM	40-300	25	1100	9	(Wang et al., 2008)
Milne Point, Alaska, USA	HPAM	45	32	500-5000	300	(Guntupalli et al., 2018)
El Corcobo, Argentina	HPAM	20-25	27-33	500-4000	160-300	(Hryc et al., 2018)

2.4. Viscous vs. Viscoelastic Polymers

There are two major types of polymers: synthetic polymers and biopolymers. Biopolymers are viscous polymers exhibiting shear thinning behavior; the viscosity decrease as shear rates increases (Azad & Trivedi, 2020). This low viscosity results in a lower injection pressure around the wellbore and ultimately higher injectivity. On the other hand, synthetic viscoelastic polymers have a shear thickening behavior that increases the viscosity with shear velocity. As such, the injection pressure will increase resulting in poor injectivity. **Figure 2.1** below illustrates the rheological behavior of both the viscoelastic polymer (purple plot) and viscous polymers (red, blue, and green plots). The viscoelastic polymers such as the HPAM are mostly used in the industry since they have advantages over the viscous polymers including cheaper price, less prone to bacterial activity, higher mobility reduction to control and slow water channeling, and availability in wide ranges of molecular weight which enables the design of different polymer systems (Al-Shakry et al., 2018). The thickening behavior of the viscoelastic polymer also improves the residual oil saturation (S_{or}) reduction at fairly higher fluxes as an extra advantage (Xie et al., 2018). Nonetheless, the low inactivity is a major drawback as stated previously. **Table 2.2** below highlights a brief comparison between the two polymer types.

Table 2.2: Comparison between viscous and viscoelastic polymers

Polymer	Viscous	Viscoelastic
Nature	Natural (biopolymer)	Synthetic
Example	Xanthan gum	HPAM
Advantages	• Higher injectivity • Relatively lesser polymer retention	• Low price • Less susceptible to bacterial activity • Higher mobility reduction • Availability in various M_w ranges • Possible S_{or} reduction
Drawbacks	• Expensive • More susceptible to bacterial activity	• Injectivity decline • Higher polymer retention

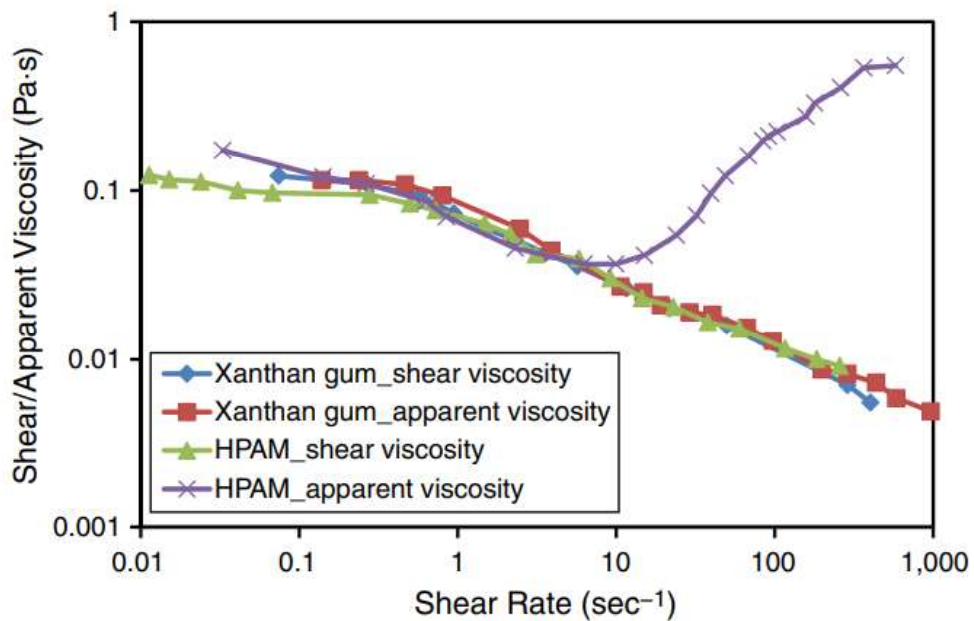


Figure 2.1: Rheological behavior of viscoelastic (HPAM) and viscous (Xanthan gum) polymers (Azad & Trivedi, 2020)

2.5. Polymer Viscoelasticity

Viscoelasticity is the property of materials which upon deformation exhibit viscous and elastic characteristics (Ostadfar, 2016). Viscoelastic polymers show a shear thickening phenomenon in porous media; in which the polymer viscosity increases after a critical onset rate (Clarke et al., 2015), see

Figure 2.2. The injection velocities near the well bore in field applications are relatively high corresponding to shear rates at which the polymer displays shear thickening behavior. The high polymer viscosity results in a high injection pressure which according to **Eqn. 2.1** causes the decline of injectivity.

$$Injectivity\ Index\ (II) = \frac{q}{\Delta p} \quad (2.1)$$

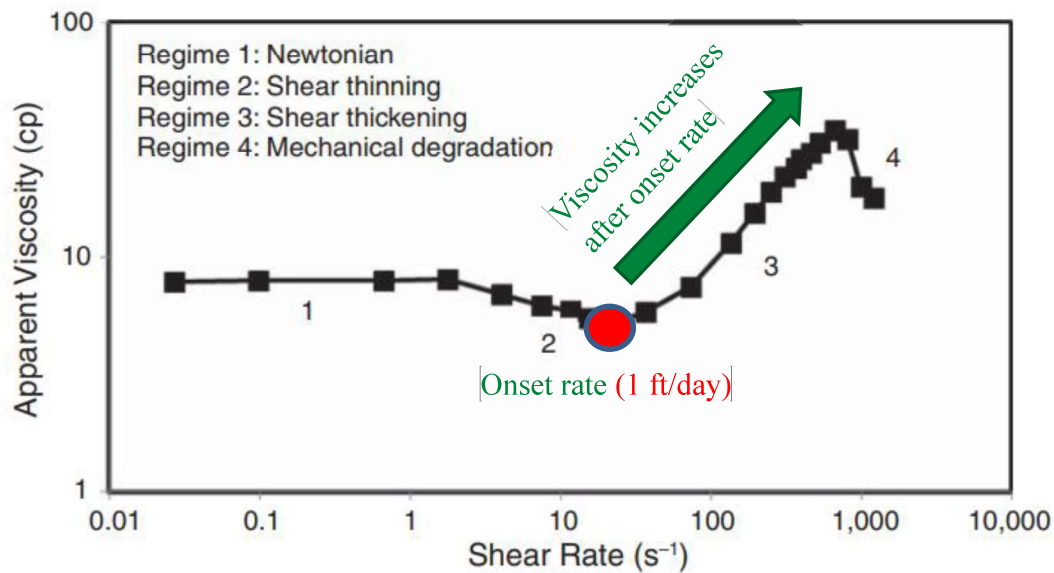


Figure 2.2: Rheological behavior of synthetic polymers (Azad & Trivedi, 2019)

Polymer viscoelasticity depend on polymer molecular weight, salinity, concentration, and temperature (Lotfollahi et al., 2016). High molecular weight and high salinity increase the viscoelasticity while temperature decrease it. The polymer concentration is an area under investigation (Glasbergen et al., 2015), but in general it increases viscoelasticity to some extent. Different combinations of those parameters produce a variety of viscoelastic polymer systems with ranging thickening index values. For instance, low molecular weight at high concentration produces higher thickening behavior than high molecular weight and low concentration (Howe et al., 2015).

Figure 2.3 summarizes the key parameters influencing polymer viscoelasticity.

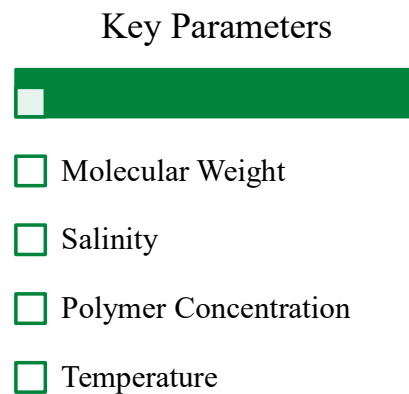


Figure 2.3: Major variables influencing the polymer viscoelasticity

The viscoelastic property of the polymer has a major advantage which influence the reduction of the residual oil saturation (Erincik et al., 2018). Polymer flooding at a flux rate of approximately 1 ft/day and higher (shear rate above the onset rate) contribute to an additional residual oil recovery (Qi et al., 2017). This additional recovery is the microscopic oil recovery which in combination with the improved macroscopic recovery (sweep efficiency) caused by polymer flooding makes the viscoelastic behaviour

appealing. Thus, this research aims to preserve the viscoelastic effect while removing the resulting negative high injection pressure. There are several options to reduce the higher injection pressure to get a comparable or slightly higher injectivity that can be generated by the viscous polymer solutions. The first option is to lower the injection rate. This option contradicts with the previously provided reservoir engineering definition as it would lead to lower oil recovery. The second option is to fracture the reservoir (Selle et al., 2013), but high attention needs to be taken when designing the fractures. The third option which is the interest of this work is drilling horizontal wells which would provide additional flow area that would reduce the apparent velocity and thus lowering the injection pressure to improve the injectivity.

2.6. Horizontal Wells

The use of horizontal wells has been rapidly increasing throughout the past decades after the advancement in technology due to the attractive advantages in recovery and injection applications. Horizontal well is a high angle well in which it has sections that have been drilled with an inclination of at least eighty degrees to the vertical wellbore to penetrate longer length of the reservoir to enhance its performance (Almajidi, 2021; Azar, 2004). **Figure 2.4** illustrates the schematic of horizontal wells. Historically, first horizontal wells drilling dates to the 1930s, but their major breakthrough was in the late 1970's and early 1980's due to the advancement of technology and increased oil prices that reignited the interest in horizontal wells (Joshi, 2003). Drilling horizontal wells was an exotic practice which held high skepticism by reservoir engineers in the 1980s. After mass horizontal drilling in the last 20 years, horizontal wells became a norm. Joshi (2003) points

out that common horizontal well length ranges between 1000 ft to 5000 ft. The well length depends on several factors including reservoir depth, reservoir, and fluids properties. For instance, Matzen field horizontal wells have a length of 800 m or 2600 ft (Sieberer et al., 2018), while Pelican Lake field attributed with high oil viscosity have wells length of 1400 m or 4600 ft (Delamaide et al., 2013).

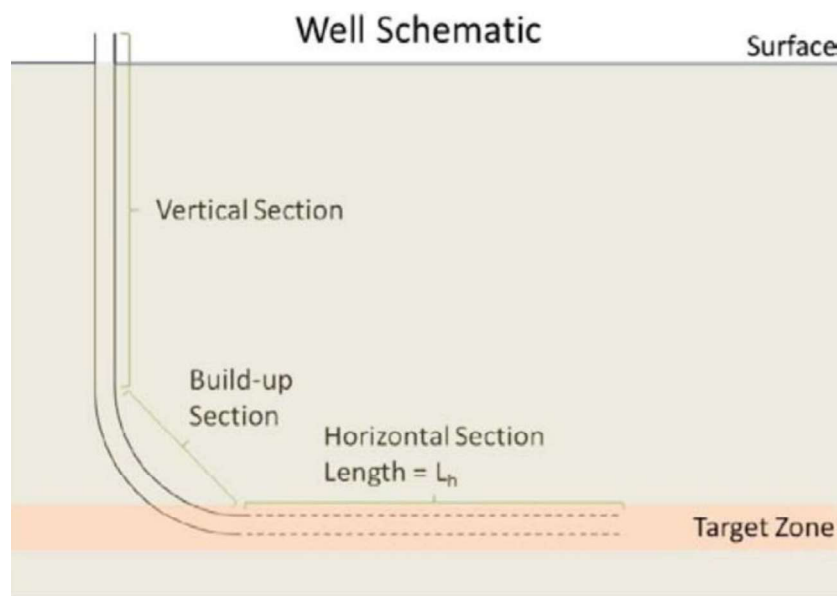


Figure 2.4: Horizontal wells schematic (Sieberer et al., 2018)

2.7. Horizontal vs. Vertical Wells

Petroleum industry was dominated by the drilling of vertical wells up to recent time in the last two decades were the horizontal drilling flourished and became the norm especially with the development of unconventional resources in tight formations. Horizontal wells have advantages over vertical wells in addition to some drawbacks. **Figure 2.5** below illustrates the difference between vertical and horizontal wells schematic orientation.

According to Joshi (2003), the benefits of horizontal wells include higher rates compared to vertical wells. Operating costs of horizontal wells are \$3 to \$4 per barrel in places where the operating cost of vertical wells range between \$7 to \$9 per barrel. Furthermore, a smaller number of horizontal wells is needed to produce or inject the same volume of fluids using vertical wells. The length of the horizontal well is not constrained by the vertical thickness of the geologic formation of which provides larger area for higher rate causing the injection pressure to be lower, thereby minimizing the risk of exceeding the maximum allowable pressure i.e., fracturing pressure (Okwen et al., 2011). In the case of viscoelastic polymer injection, the near wellbore area in the vertical well will experience higher rate corresponding to high injection pressure and lower injectivity (Sieberer et al., 2018). Furthermore, horizontal wells solve the production/injection problems in low permeability formations (Taber & Seright, 1992).

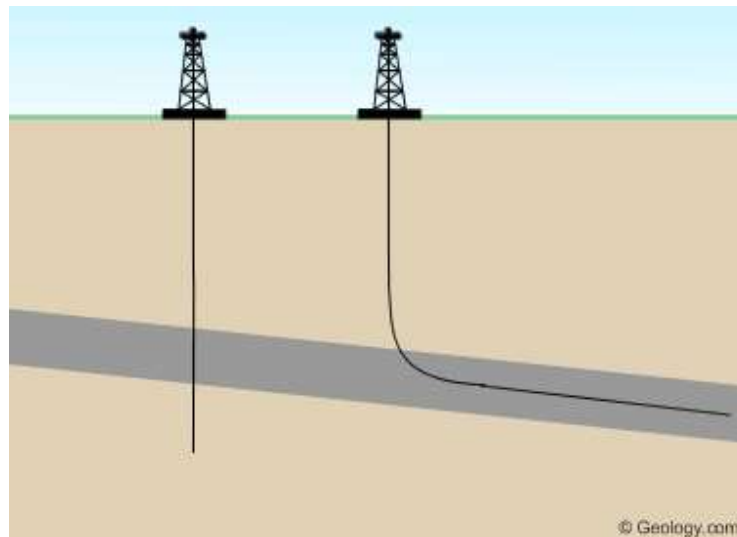


Figure 2.5: Horizontal vs vertical wells schematic (source: <https://geology.com/>)

The disadvantages of horizontal wells are 65% probability of commercial success which improves as more wells are drilled (Joshi, 2003). This means that only 2 out of 3 wells are commercially producing. Another disadvantage stated by Joshi (2003) is only one zone can be produced at a time which makes it difficult to produce from reservoirs with multiple pay zones that have different permeabilities and large difference in vertical depth. This problem is encountered nowadays by drilling multi-lateral horizontal wells, which is more expensive than the normal single lateral wells. In general, a horizontal well is 1.5 to 2.5 more expensive than vertical well and the re-entry costs are 0.3 to 1.4 greater (Joshi, 2003). The drilling costs of horizontal wells for both injectors and producers are estimated as EUR 3.0 million per well or \$3.2 million per well, while the vertical well drilling costs for injectors and producers is estimated as EUR 1.7 million per well or \$1.81 million per well (Sieberer et al., 2018). Sieberer et al. (2018) elaborate on the drilling cost of horizontal wells as EUR 1300/m or \$424/ft.

2.8. Horizontal Wells Application for Polymer Injection

As discussed in the previous sections, multiple alternatives exist to mitigate the high injection pressure issue corresponding to viscoelastic polymer shear thickening behavior that causes high velocity around the well bore of the vertical well. Reducing the injection rate is out of the question as our application of EOR in relation to reservoir engineering definition is to maximize the economic return from the production of mature reservoirs. The second option is injection under fracturing conditions, but the fracture growth needs to be controlled properly to avoid fracturing with fast rate or out of zone

(Glasbergen et al., 2015). The third option which is the focus of this thesis work is the application of horizontal wells for viscoelastic polymer flooding.

Horizontal wells are employed to increase the flow area. The fluids are going to experience low velocity around the wellbore, as indicated by **Eqn. 2.2**, and thereby it can avoid the shear thickening regime (Glasbergen et al., 2015). This would lower the injection pressure to avoid undesired fracturing of the reservoir and in return would bring the injectivity to a comparable value of that generated by viscous polymer solutions.

$$\text{Velocity (shear rate): } v = \frac{q}{A} \quad (2.2)$$

However, optimizing the horizontal well length is of high importance. The reason is lengthy horizontal wells are expensive (Almajidi, 2021) as the drilling cost is around EUR 1300/m or \$424/ft. Furthermore, unnecessarily lengthy horizontal well would abolish the viscoelastic effect contributing to additional micro recovery caused by reduction of S_{or} (Azad & Trivedi, 2020). Polymer systems with low shear thickening index require less horizontal length than the viscoelastic polymers with high thickening index. Determining the necessary horizontal length required for various systems with different oil viscosity, polymer viscosity, rock permeability, and polymer viscoelasticity is vital for improving the injectivity index.

CHAPTER 3

METHODOLOGY

3.1. Simulation Procedure

The sequence of simulation work is summarized in the following flow chart.

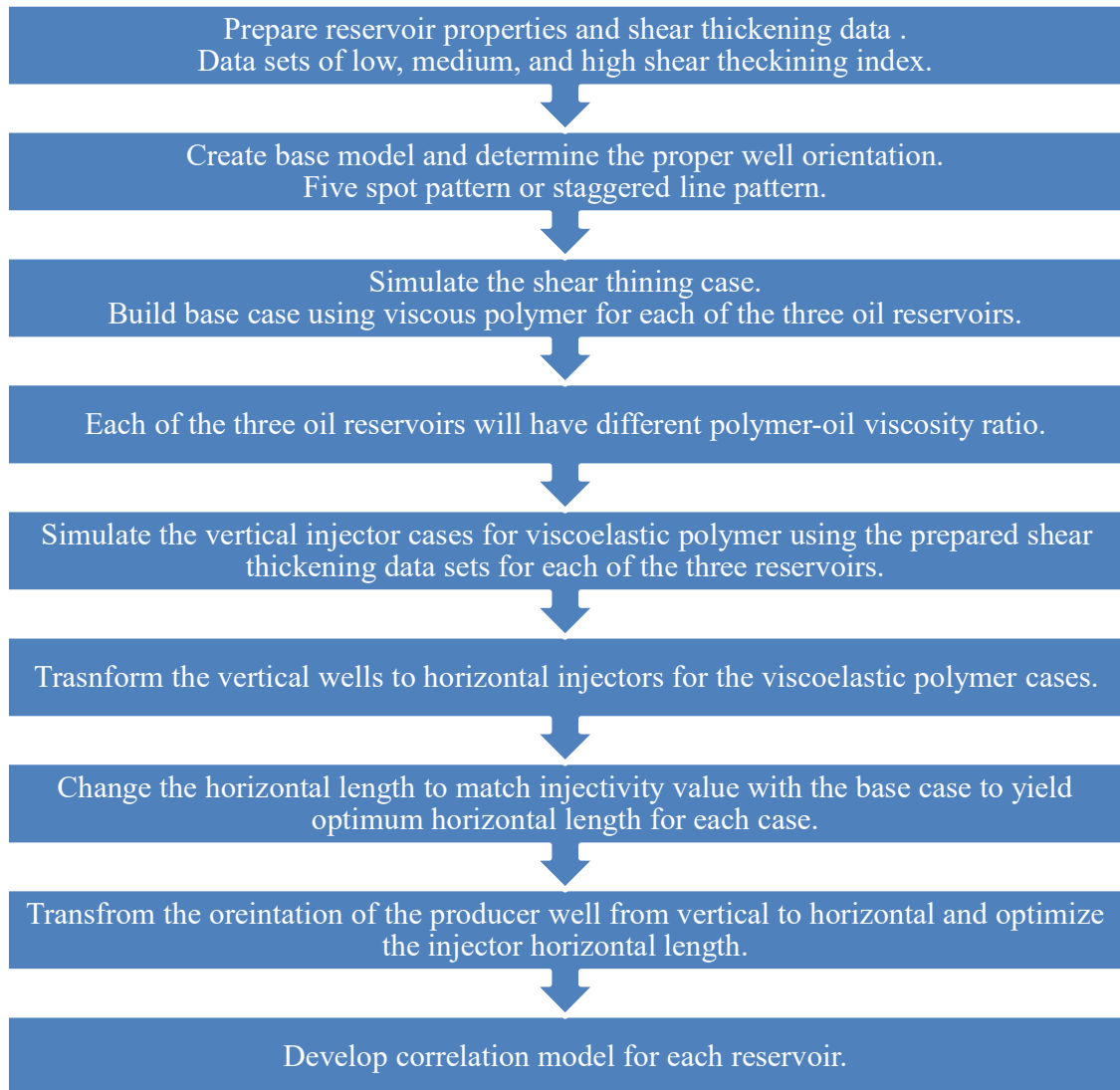


Figure 3.1: Flowchart of the simulation work

3.2. Model Description

The three fields reservoir properties were obtained from literature. Three polymer viscosities were considered to vary the viscosity ratios. Furthermore, three shear thickening data sets were prepared for each of the three polymer viscosities for all field cases to obtain low ($N_2 = 1.173$), medium ($N_2 = 1.6554$), and high ($N_2 = 1.925$) thickening index values. Shear thickening data is generated for representing polymer systems with different non-linear viscoelasticity. An additional data set representing the shear thinning viscous polymer behavior ($N_1 = 0.5$) was also prepared. It is worth mentioning that the polymer shear thickening data were prepared manually instead of in the lab to formulate multiple data sets with consistent shear thickening indices for each case. The initial polymer viscosity was used to vary the behavior of the polymer to achieve the three low ($N_2 = 1.173$), medium ($N_2 = 1.6554$), and high ($N_2 = 1.925$) thickening index values and shear thinning viscous polymer behavior ($N_1 = 0.5$).

The shear thinning case would be the base case as it would generate the highest value of the injectivity using vertical well. The horizontal well length of the shear thickening cases will be optimized to obtain a comparable or slightly higher injectivity value.

3.2.1. Matzen Field Reservoir Properties and Polymer Data

Matzen field is considered one of the largest hydrocarbon fields in Europe and is located 30 km north-east of Vienna in Austria. Matzen field produces from the 8 TH sandstone reservoir (Van Laer, 2016). **Table 3.1** summarizes Matzen reservoir properties. The grid size for the constructed model is 100 ft by 100 ft and the selected dimension is

5500 ft by 7000 ft which is an average area for pilot projects (Delazeri & Lamas, 2021).

Figure 3.2 illustrates the grid model constructed using Schlumberger ECLIPSE reservoir simulation software.

Table 3.1: Matzen field reservoir properties and model parameters (Van Laer, 2016; Zechner et al., 2014)

Parameter	Value
DX	100 ft
DY	100 ft
DZ	65.6 ft
X	5500 ft
Y	7000 ft
Z	65.6 ft
K_x	500 mD
K_y	500 mD
K_z	500 mD
Porosity	0.25
P_i	1639 psi
P_f	2600 psi
C_r	$3 \times 10^{-6} \text{ psi}^{-1}$
Reservoir Top	3772 ft
Polymer Viscosity	2.5 cP / 10 cP / 100 cP
Oil viscosity	19 cP

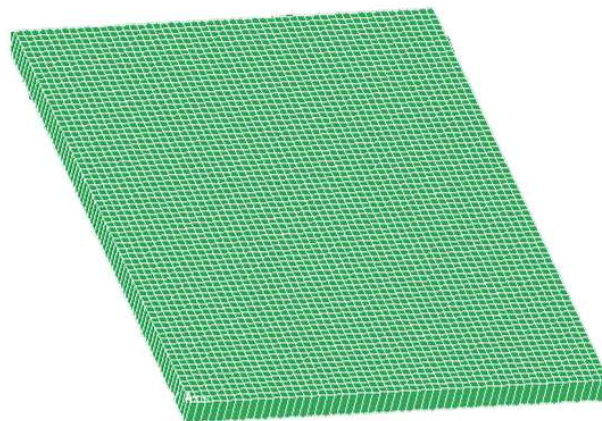


Figure 3.2: Matzen Field grid model of 55 X 70 X 1 dimensions

Matzen field polymer flooding project is considered one of the most successful around the globe (Lüftenegger et al., 2015). HPAM polymer of 10 cP viscosity was used in this project. For the sake of varying the viscosity ratio, two other polymer viscosities of different orders (2.5 cP and 100 cP) were used along the actual 10 cP viscosity. Many parameters such as molecular weight, polymer concentration, and salinity can be varied to achieve different thickening indices. **Figure 3.3-3.6** below illustrate the 4 aforementioned polymer thickening index cases for the 10 cP. The other shear thickening data for the 2.5 cP and 100 cP can be found in Appendix A.

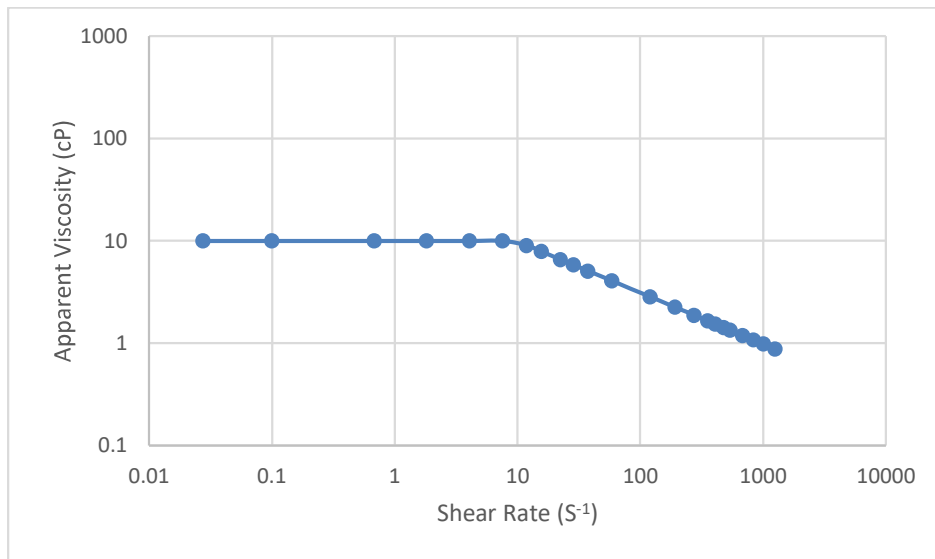


Figure 3.3: Matzen field 10 cP polymer shear thinning data set ($N_1 = 0.5$)

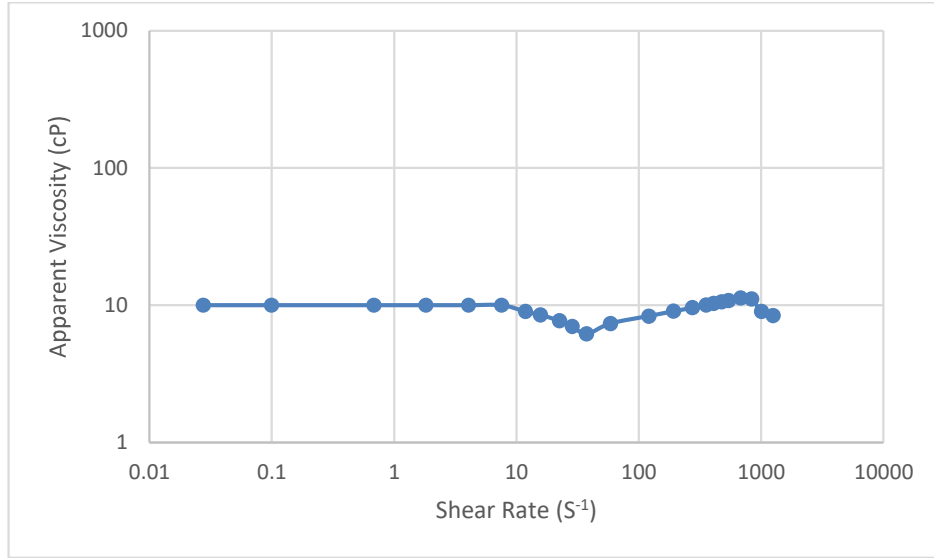


Figure 3.4: Matzen field 10 cP polymer low shear thickening data set ($N_2 = 1.173$)

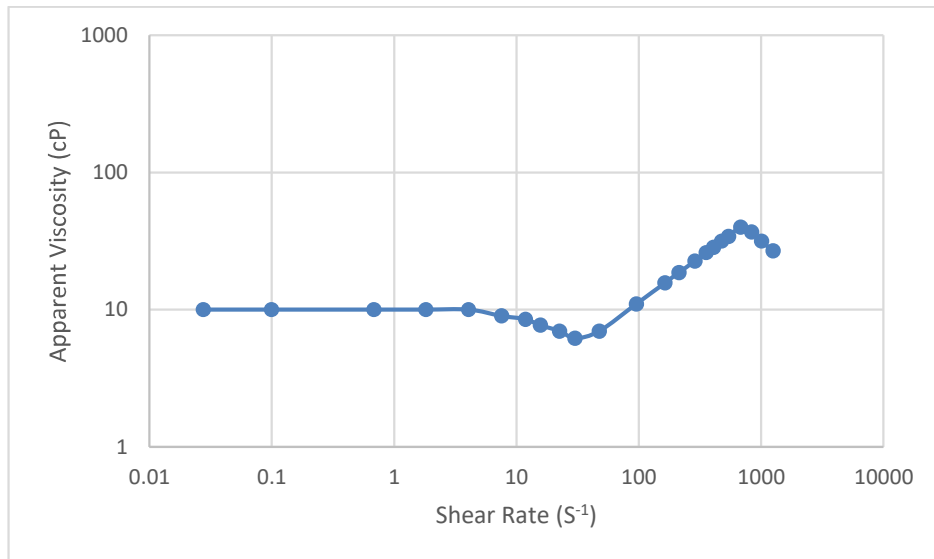


Figure 3.5: Matzen field 10 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

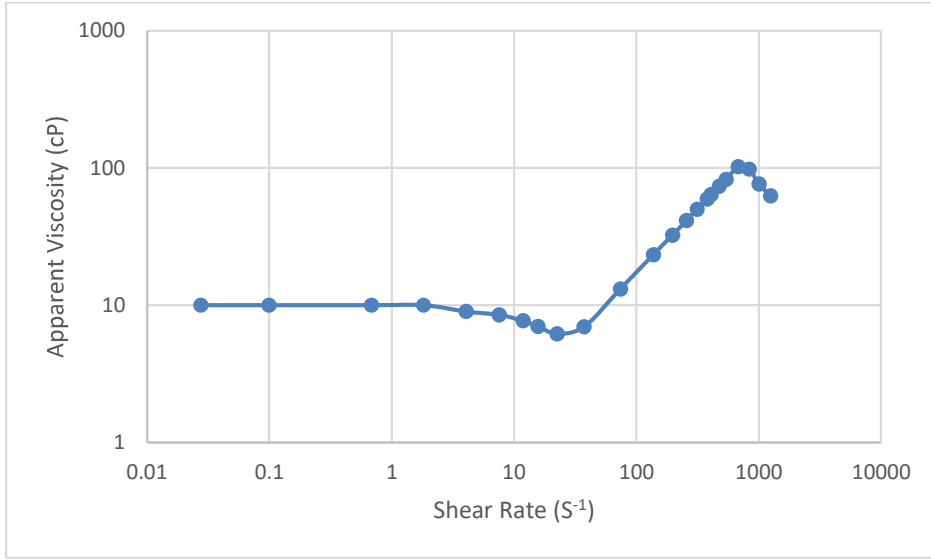


Figure 3.6: Matzen field 10 cP polymer high shear thickening data set ($N_2 = 1.925$)

All cases have similar viscosity (10 cP) in the Newtonian region. However, as the shear thickening index (N_2) increases, the polymer viscosity in the shear thickening region increases and the onset rate decreases, meaning that the polymer experiences earlier shear thinning and thickening behavior.

3.2.2. Daqing Field Reservoir Properties and Polymer Data

Daqing field is the largest hydrocarbon oil field in China (Ezeh et al., 2021a). It is produced from the Songliao sandstone reservoir. **Table 3.2** summarizes Daqing reservoir properties. The grid size for the constructed model is 100 ft by 100 ft and the selected dimension is 5500 ft by 7000 ft which is the same as Matzen field model to keep the area constant for all three cases and since it is an average pilot area. **Figure 3.7** illustrates the grid model constructed using Schlumberger ECLIPSE reservoir simulation software.

Table 3.2: Daqing field reservoir properties and model parameters (Ezeh et al., 2021a; Shankar & Sharma, 2023)

Parameter	Value
DX	100 ft
DY	100 ft
DZ	59.04 ft
X	5500 ft
Y	7000 ft
Z	59.04 ft
K _X	1100 mD
K _Y	1100 mD
K _Z	1100 mD
Porosity	0.25
P _i	1688 psi
P _f	2600 psi
C _r	3 x 10 ⁻⁶ psi ⁻¹
Reservoir Top	3444 ft
Polymer Viscosity	3 cP / 30 cP / 300 cP
Oil viscosity	10 cP

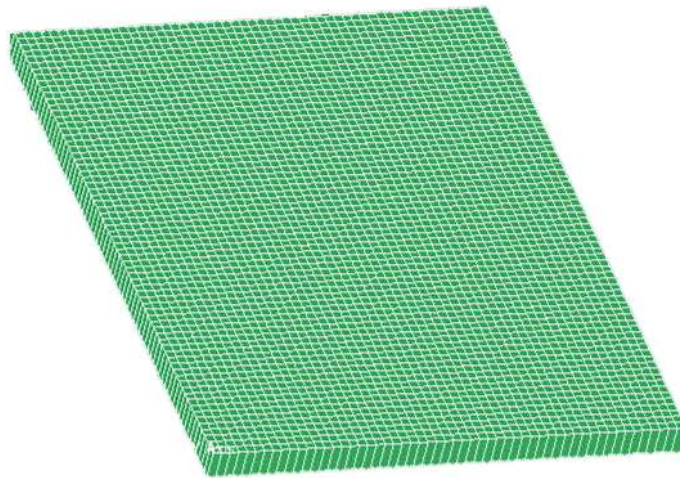


Figure 3.7: Daqing Field grid model of 55 X 70 X 1 dimensions

Daqing field polymer flooding project is considered one of the most successful around the globe (Lüftenegger et al., 2015). HPAM polymer of 300 cP viscosity was used in this project. For the sake of varying the viscosity ratio, two other polymer viscosities of

different orders (3 cP and 30 cP) were used along the actual 300 cP viscosity. **Figure 3.8-3.11** below illustrate the 4 polymer thickening index cases for the 10 cP. The other shear thickening data for the 3 cP and 30 cP can be found in Appendix A.

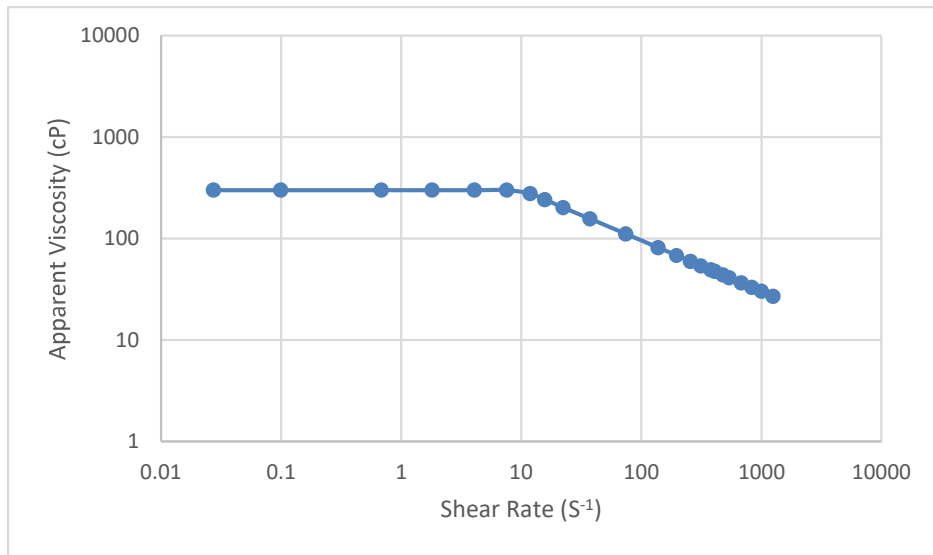


Figure 3.8: Daqing field 300 cP polymer shear thinning data set ($N_1 = 0.5$)

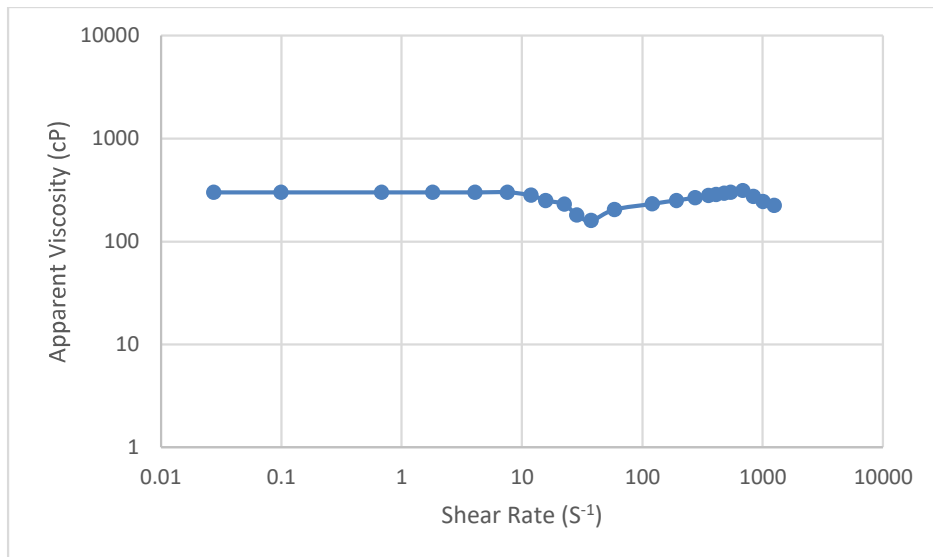


Figure 3.9: Daqing field 300 cP polymer low shear thickening data set ($N_2 = 1.173$)

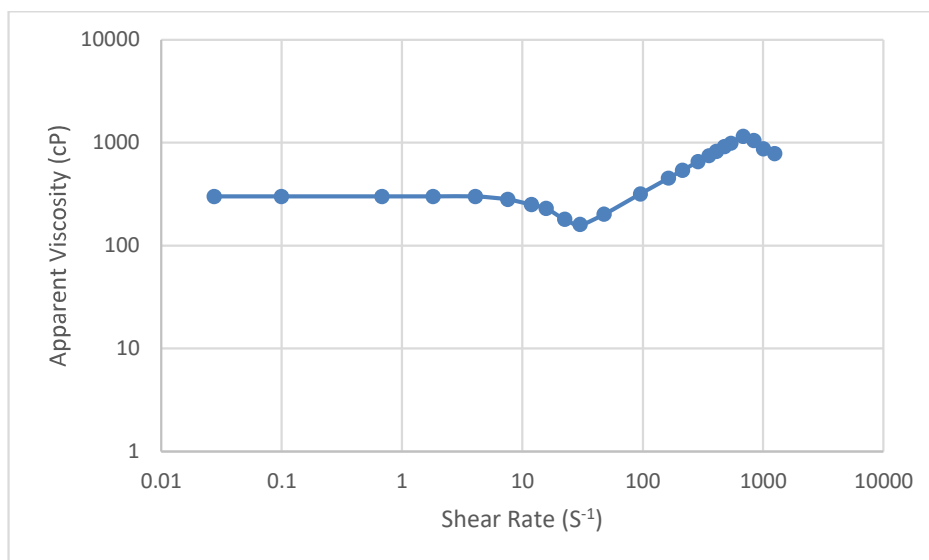


Figure 3.10: Daqing field 300 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

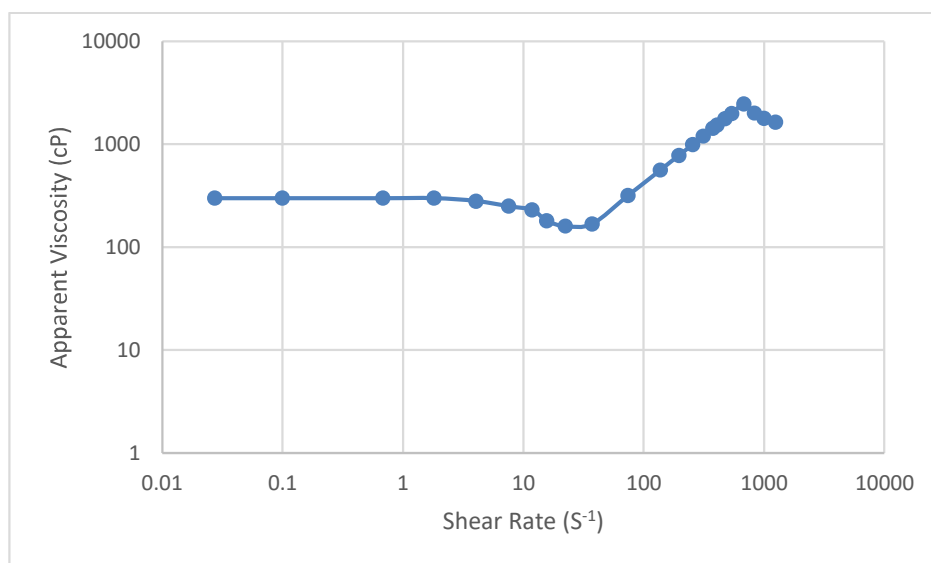


Figure 3.11: Daqing field 300 cP polymer high shear thickening data set ($N_2 = 1.925$)

3.2.3. Pelican Lake Field Reservoir Properties and Polymer Data

Pelican Lake field is located in Canada and is produced from the Wabiskaw unconsolidated sandstone reservoir. **Table 3.3** summarizes Pelican Lake reservoir properties. The grid size for the constructed model is 100 ft by 100 ft and the selected dimension is 5500 ft by 7000 ft which is the same as the previous two cases. **Figure 3.7** illustrates the grid model constructed using Schlumberger ECLIPSE reservoir simulation software.

Table 3.3: Pelican Lake field reservoir properties and model parameters (Delazeri & Lamas, 2021; Fossey et al., 1997)

Parameter	Value
DX	100 ft
DY	100 ft
DZ	16.4 ft
X	5500 ft
Y	7000 ft
Z	16.4 ft
K _X	5000 mD
K _Y	5000 mD
K _Z	5000 mD
Porosity	0.3
P _i	1312 psi
P _f	∞ psi (unconsolidated)
C _r	3 x 10 ⁻⁶ psi ⁻¹
Reservoir Top	1312 ft
Polymer Viscosity	3 cP / 30 cP / 300 cP
Oil viscosity	3000 cP

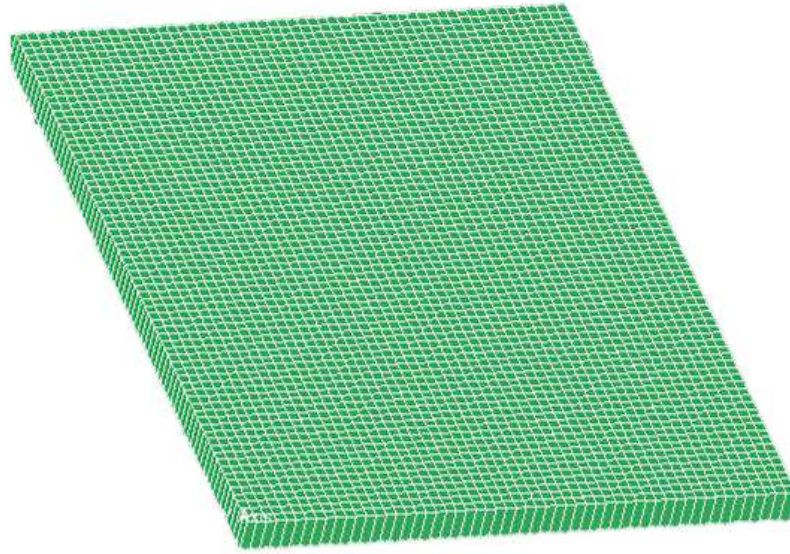


Figure 3.12: Pelican Lake Field grid model of 55 X 70 X 1 dimensions

Pelican Lake field polymer flooding project is considered one of the most successful around the globe (Lüftenegger et al., 2015). HPAM polymer of 30 cP viscosity was used in this project. For the sake of varying the viscosity ratio, two other polymer viscosities of different orders (3 cP and 300 cP) were used along the actual 30 cP viscosity. However, due to the high viscous nature of the oil (3000 cP), the case of 300 cP was not possible to be run through the simulation software as the polymer additional viscosity make it more difficult to inject in the reservoir. Thus, only the actual polymer viscosity 30 cP along with 3 cP were considered for Pelican Lake case. **Figure 3.13-3.16** below illustrate the 4 polymer thickening index cases for the 10 cP. The other shear thickening data for the 3 cP and 30 cP can be found in Appendix A.

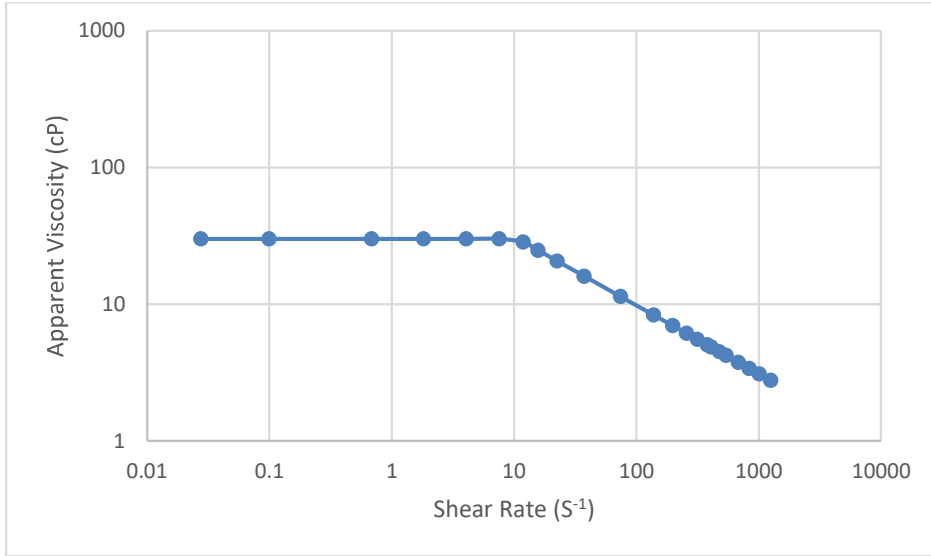


Figure 3.13: Pelican Lake field 30 cP polymer shear thinning data set ($N_1 = 0.5$)

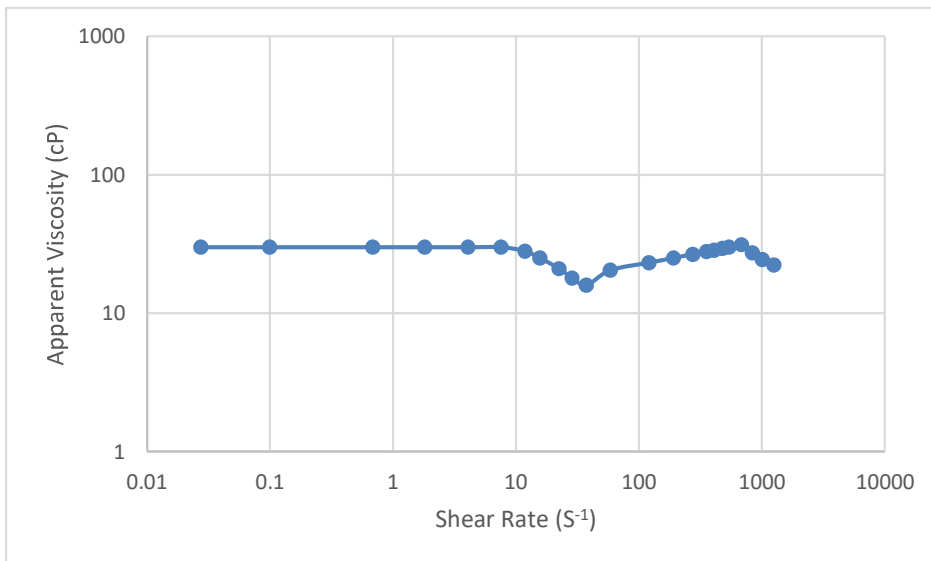


Figure 3.14: Pelican Lake field 30 cP polymer low shear thickening data set ($N_2 = 1.173$)

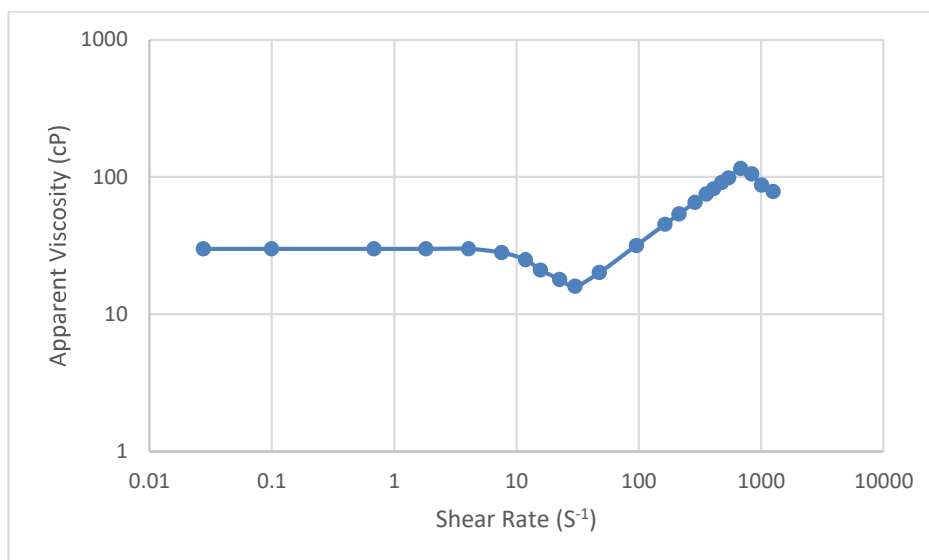


Figure 3.15: Pelican Lake field 30 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

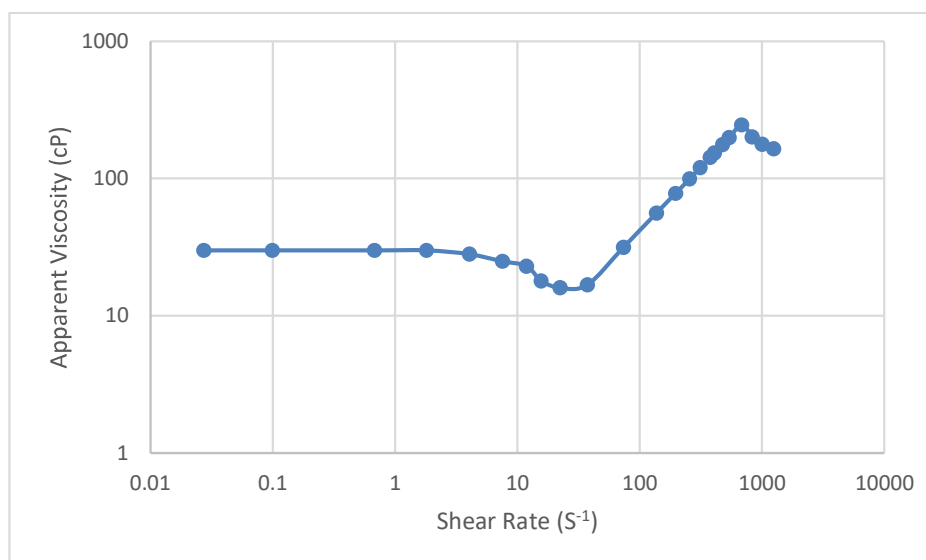


Figure 3.16: Pelican Lake field 30 cP polymer high shear thickening data set ($N_2 = 1.925$)

3.3. Well Orientation

3.3.1. Injector Well Orientation

Two injection orientations were considered: the five-spot pattern and the staggered line pattern, **Figure 3.17** and **4.12**. For the thinning polymer, only vertical well orientation was considered for all cases since the injection pressure and injectivity index results of this case will be similar for both vertical and horizontal well orientations.

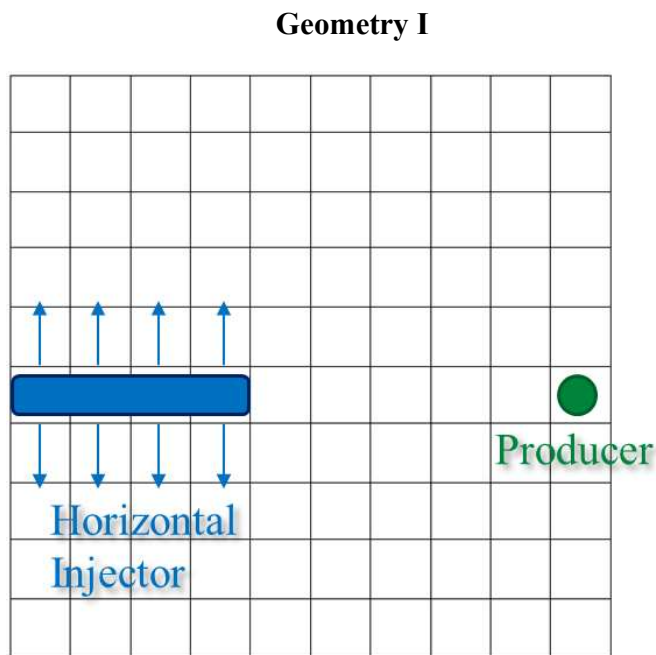


Figure 3.17: Five spot pattern

Geometry II

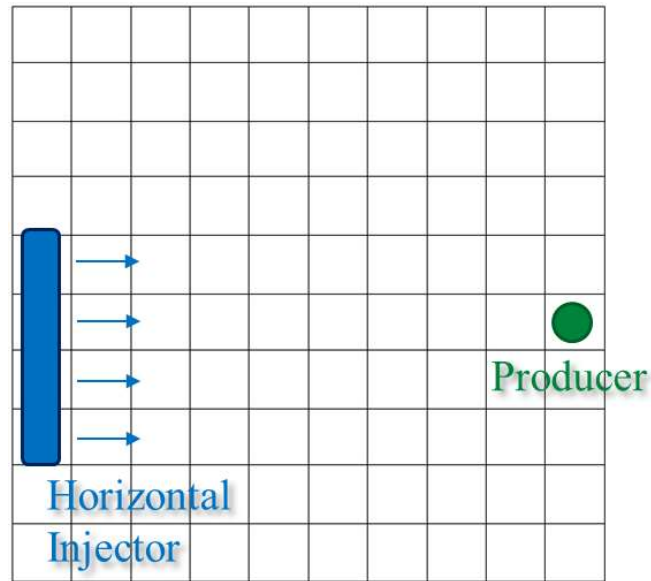


Figure 3.18: Staggered line pattern

After running the scenarios of the vertical and horizontal case for thickening cases and comparing them to the thinning polymer base case, decision was made to select the staggered line geometry for this entire thesis work. For users who want to use the correlation model developed by this work using the staggered line geometry, they can use the methodology this work followed to develop their own correlation using the well pattern they have. The horizontal well following five spot pattern is represented by the green curve while staggered line horizontal well by the red curve.

The reason for selecting the staggered line includes first of all lower injection pressure, **Figure 3.19**. The staggered line geometry resulted in a lower injection that is closer to the value of the thinning base case injection pressure.

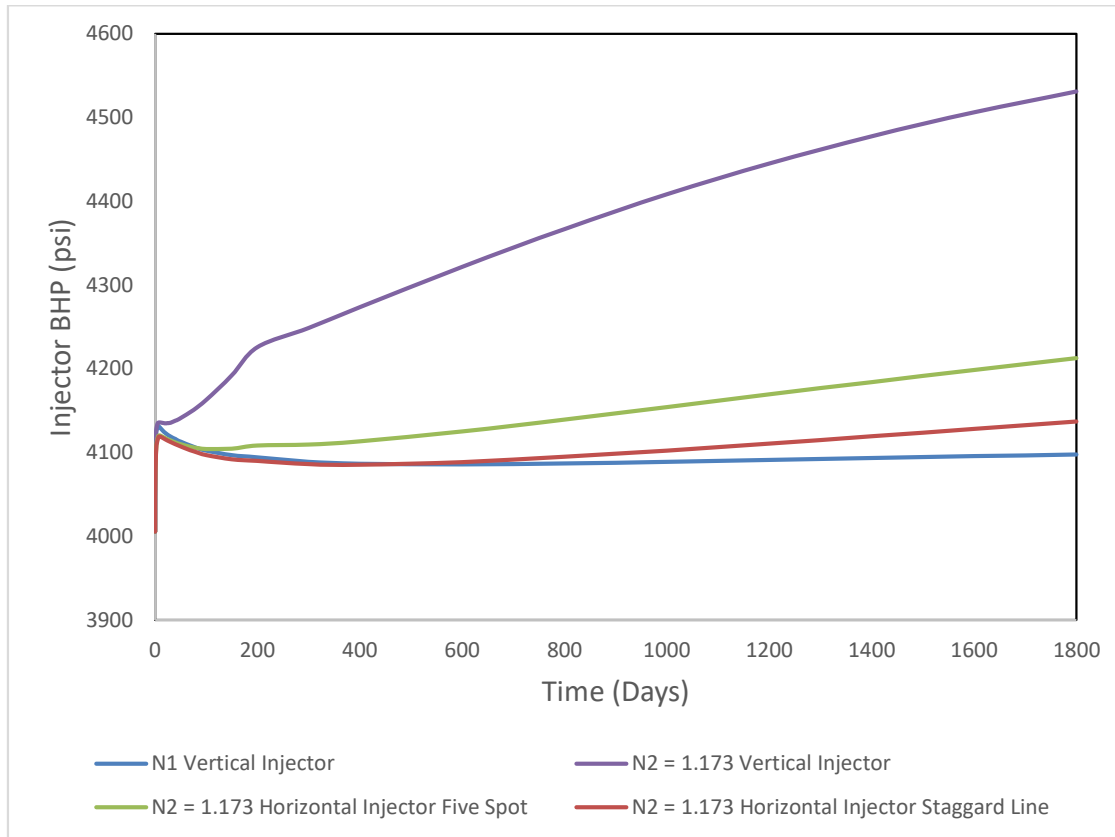


Figure 3.19: Injection pressure of five spot and staggered line geometry cases

The second reason for selecting the staggered is the higher injectivity index, **Figure 3.20**. The staggered line geometry resulted in a higher injectivity that is slightly higher than the value of the thinning base case. This was considered until five hundred days which is a typical duration for pilot tests. On the other hand, the five-spot pattern resulted in an injectivity index value lower than the thinning case. This means that the five-spot pattern will require longer horizontal wells to generate injectivity values comparable to the thinning index case. For an optimum horizontal length, the staggered line is a more attractive configuration.

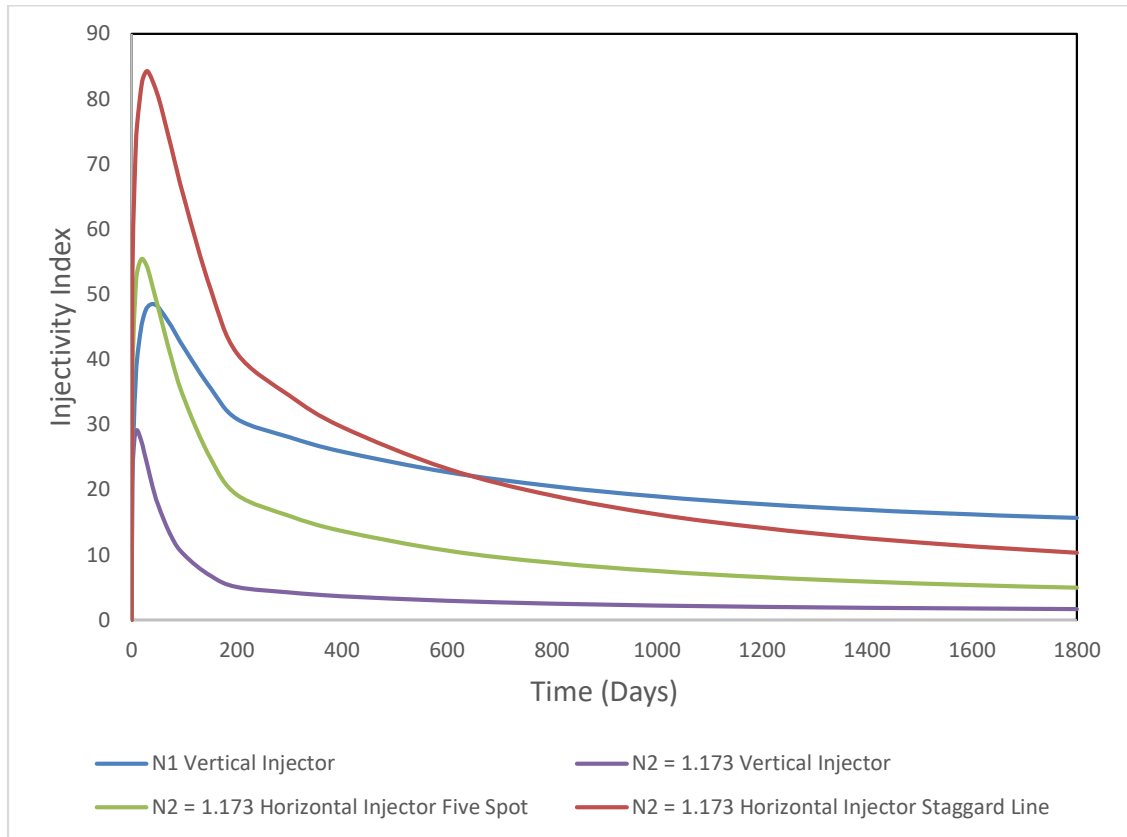


Figure 3.20: Injectivity index of five spot and staggered line geometry cases

As for the oil recovery, **Figure 3.21**, the staggered line pattern caused a higher recovery value than the five-spot pattern. The oil recovery of the horizontal five-spot pattern was lower than both the vertical cases of the shear thinning and shear thickening polymers. This means that the economics favors the staggered line option. Nonetheless, the injection pressure and injectivity index were the major factors in the consideration of going with the staggered line as it would require shorter horizontal length which is cheaper and results in more oil recovery i.e., more profit.

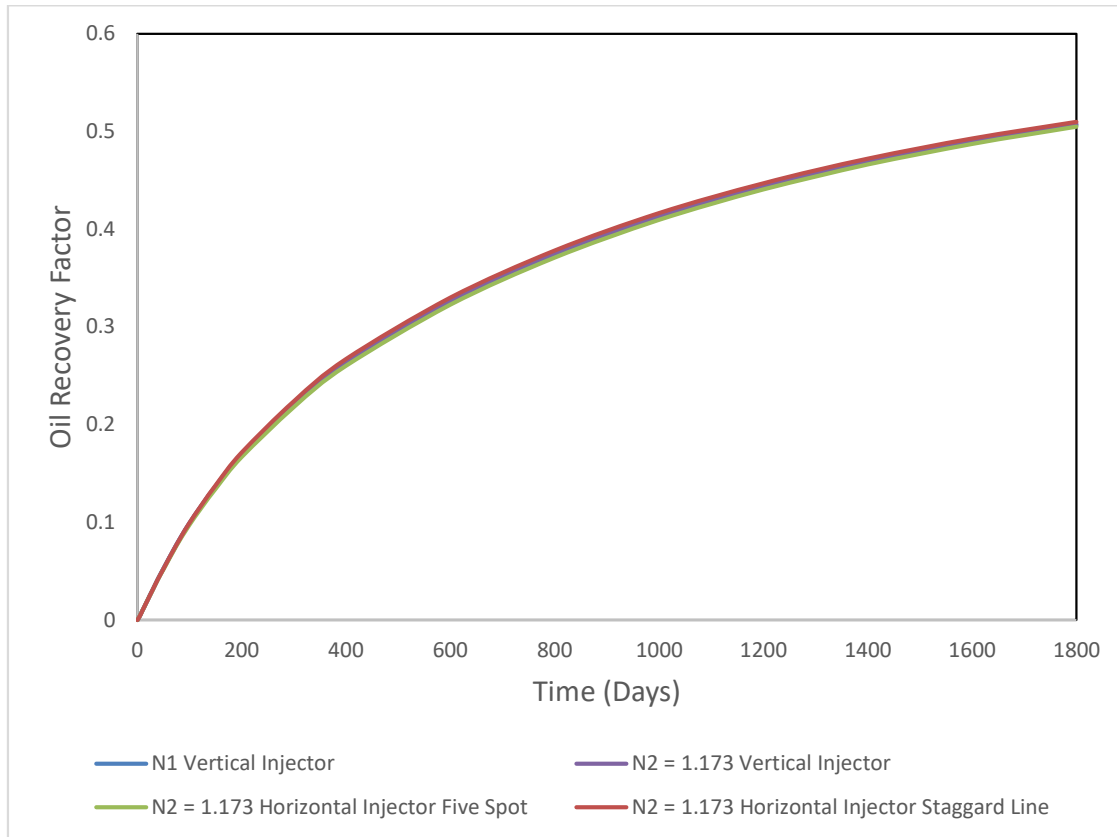


Figure 3.21: Oil recovery of five spot and staggered line geometry cases

3.3.2. Vertical vs Horizontal Producer Well Orientation

This thesis work studied the producer well orientation on the optimum injector horizontal length. In the three field cases, Matzen and Pelican Lake fields were produced using horizontal producers while Daqing was produced via vertical producers. To make the parameters of interest uniform and to rule out any discrepancy on this study, it was considered to investigate both well orientations for the producer. **Figure 3.22** illustrates the vertical producer orientation while **Figure 3.23** shows the horizontal producer orientation. The horizontal length for the producer was fixed at 1000 ft for all cases.

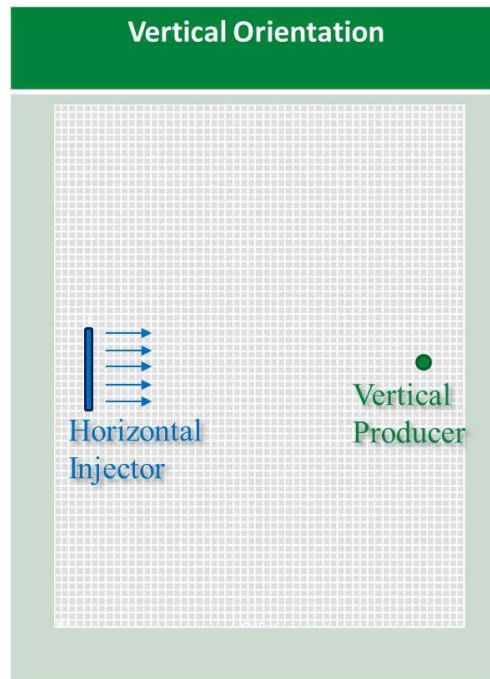


Figure 3.22: Vertical well orientation of producer

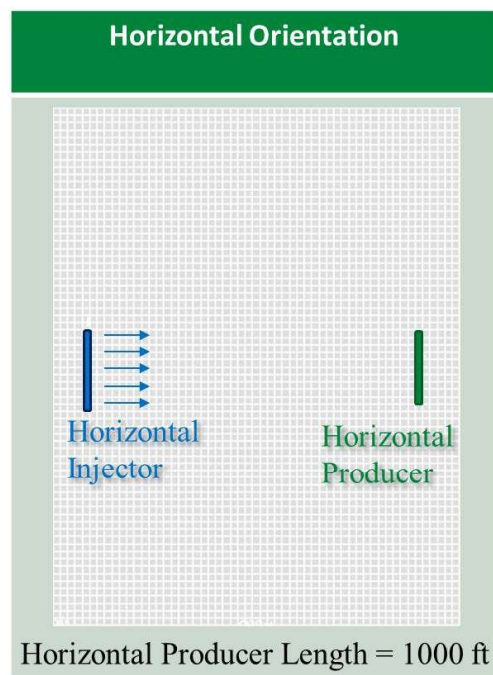


Figure 3.23: Horizontal well orientation of producer with a length of 1000 ft

CHAPTER 4

RESULTS AND CONCLUSION

4.1. General Results

All simulated cases were developed using a staggered line pattern. The thinning polymer case was selected as a vertical injector. This case is the base case against which all shear thickening cases will be compared to. The aim is to focus on improving the injectivity by changing the injector well orientation and horizontal length. The producer bottom hole pressure (BHP) was fixed at 100 psi and injection rate was kept constant at 500 BBL/Day for all cases.

The first step was simulating all thickening viscoelastic polymer cases using vertical well orientation. Results matched the proposed hypothesis, where the thinning polymer vertical case (N_1) had higher injectivity, see **Figure 4.1**, and lower injection pressure, **Figure 4.2**, in comparison to the thickening cases (N_2).

It can also be observed that as the thickening index increases, the injection pressure increases, and the injectivity decreases which causes the oil recovery to decline. The highest thickening cases with thickening index $N_2 = 1.6554$ and $N_2 = 1.925$ reached the injection pressure limit 5000 psi, i.e., the fracture pressure (**Figure 4.2**). This causes the injection rate to decline and consequently affecting the oil recovery.

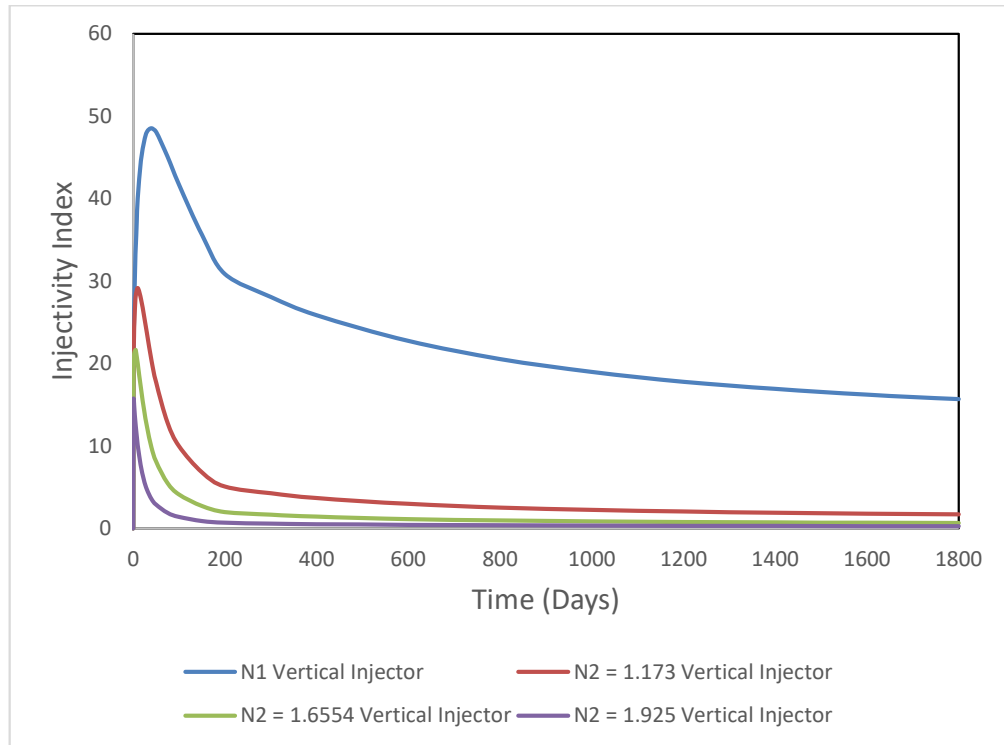


Figure 4.1: Injectivity Index of vertical well cases

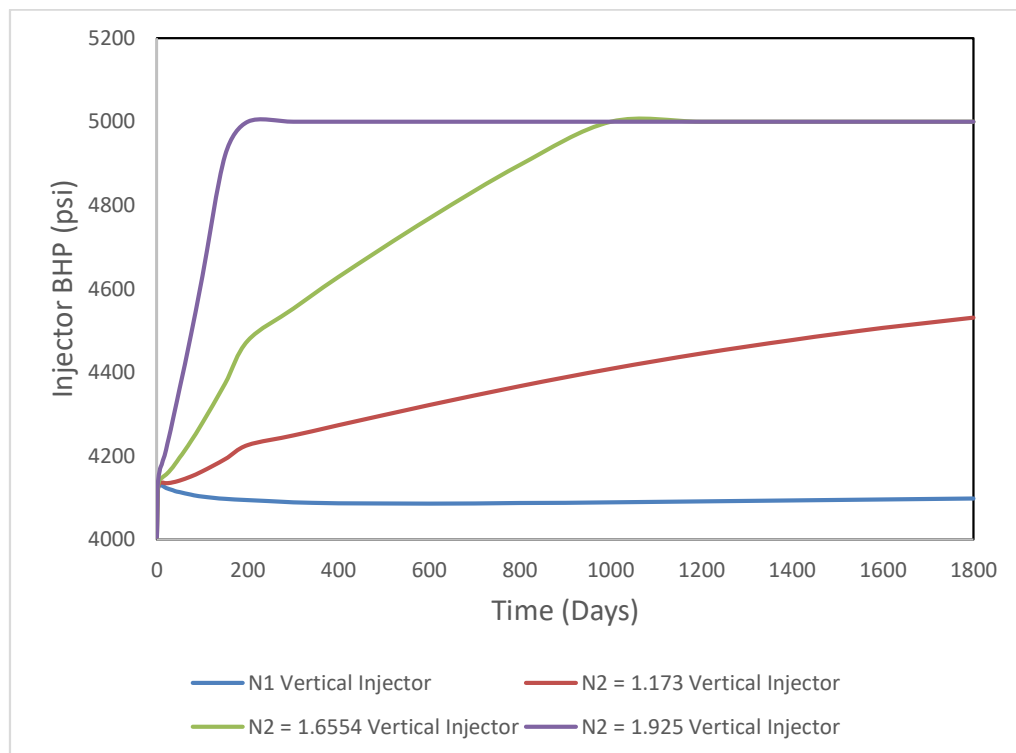


Figure 4.2: Injection pressure of vertical well cases

The second phase of the simulation work was to change the injectors orientation of the thickening cases from vertical to horizontal. The length was varied while observing the changes on the injectivity index and injection pressure curves. The aim was to have a comparable or slightly higher injectivity to that generated by the thinning cases for at least 500 days which is a typical duration of pilot projects.

The obtained results show that the optimized horizontal orientation improved the injectivity index of the viscoelastic polymers to a value that slightly higher than the viscous polymer, **Figure 4.3**. Furthermore, the optimized cases lowered the injection pressure to a value that is almost matching that of the thinning polymer base case, **Figure 4.4**.

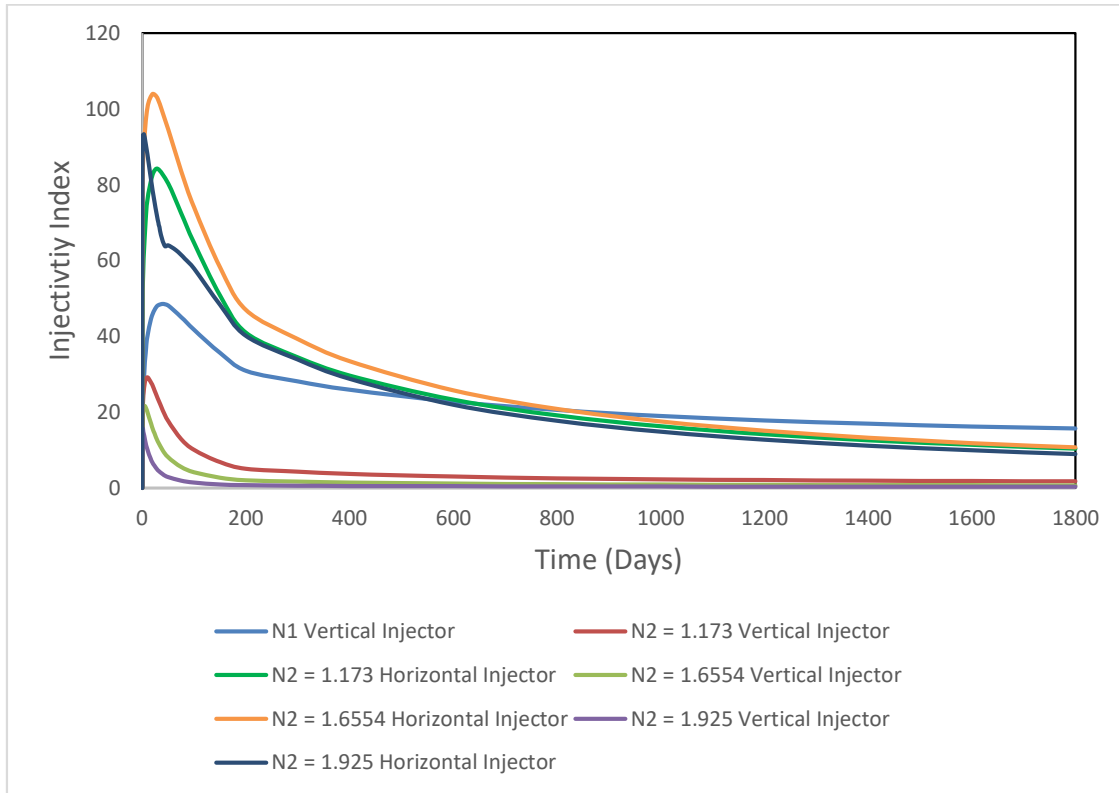


Figure 4.3: Injectivity index of the optimized horizontal cases. Values are slightly higher than the thinning base case (N_1). Vertical cases of viscoelastic thickening polymer have low injectivity than the thinning base case.

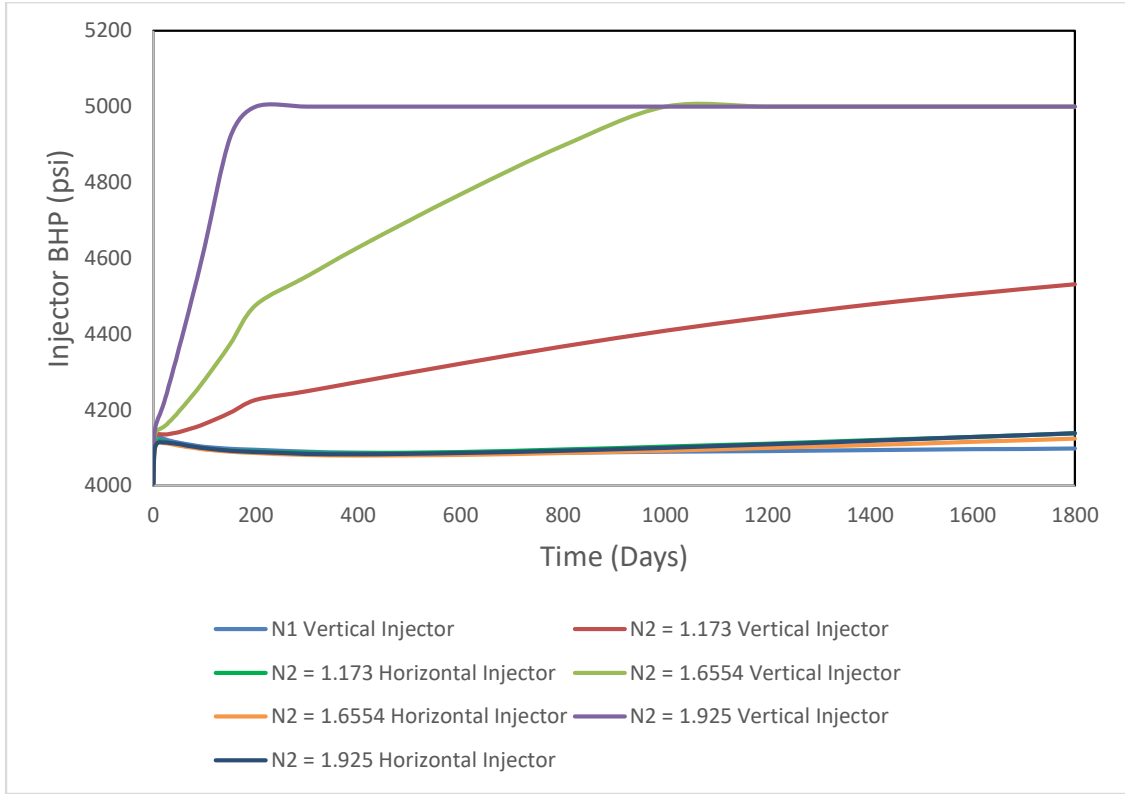


Figure 4.4: Injectivity pressure of the optimized horizontal cases is comparable to the thinning base case (N_1). Vertical cases of viscoelastic thickening polymer have high injection pressure than the thinning base case (N_1).

The injection rate of the optimized horizontal cases was matching the rate of the thinning base case, **Figure 4.5**. The drop in the rate from 500 bbl/day to 250 bbl/day at 200 days is attributed to the fixed production rate that was set. When the pressure wave generated by the injection reached the producer, it increased its bottom hole pressure (BHP) and enhanced its productivity. However, after the production rate reached the fixed limit, the injection rate was decreased to stabilize the production BHP and produce at a constant rate. The rates of the high thickening index $N_2 = 1.6554$ and $N_2 = 1.925$ cases continued to deteriorate due to reaching the fracture pressure limit. As a results, all cases having the

same injection rate of the thinning base case had similar cumulative injected volume while the two vertical high thickening cases has lower total injected volume, **Figure 4.6**.

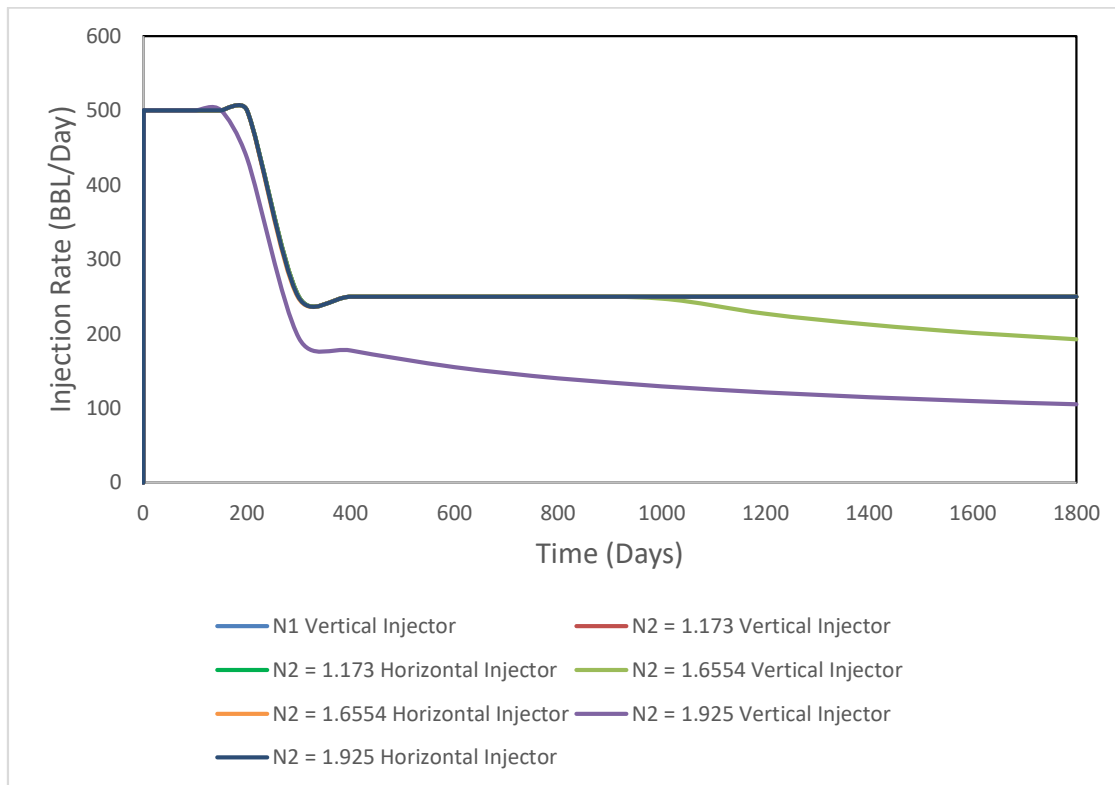


Figure 4.5: Injectivity rate of the optimized horizontal cases is similar to the thinning base case. Vertical cases of high thickening polymer have lower injection rate than the thinning base case (N_1).

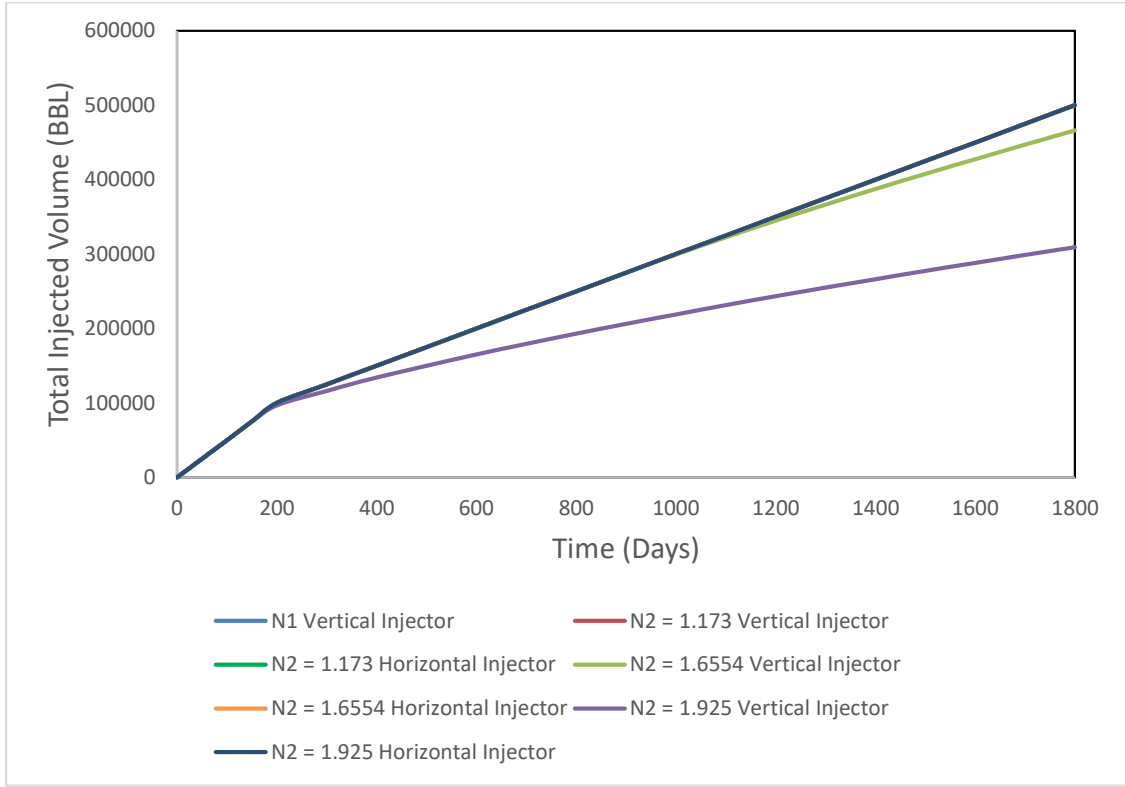


Figure 4.6: Total injected volume of the optimized horizontal cases is similar to the thinning base case (N_1) except of the two high thickening index cases.

As for the total oil recovery, **Figure 4.7**, the vertical cases of the thickening index polymer had lower recovery than the thinning base case. This is due to the high injection pressure caused by the viscoelastic behavior of the polymer. However, the optimized horizontal cases resulted in an oil recovery that is higher than the thinning base case. The highest thickening index case $N_2 = 1.925$ resulted in the highest recovery followed by $N_2 = 1.6554$ and then $N_2 = 1.173$. This might be attributed to the additional microscopic oil recovery caused by the viscoelastic effect discussed previously. Thus, removing the negative effect of the viscoelasticity while preserving the thickening behavior of the polymer helped in further reduction of residual oil saturation S_{or} .

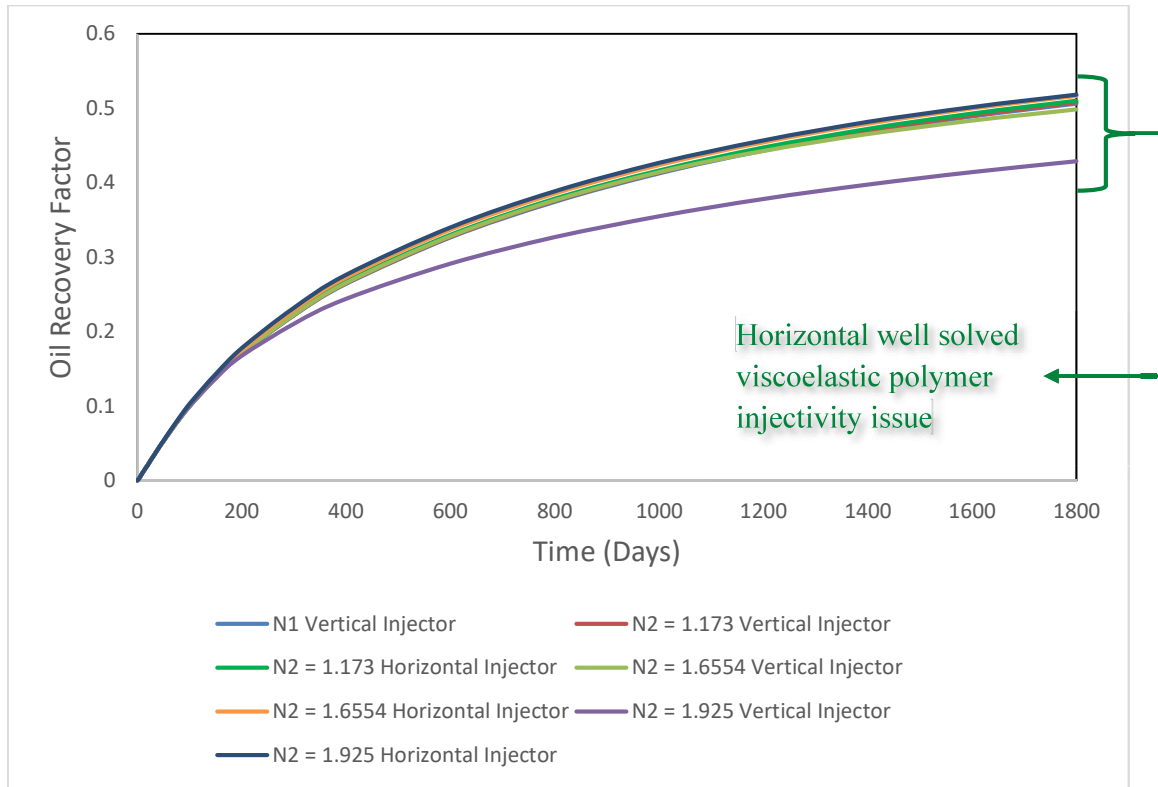


Figure 4.7: Oil recovery of the optimized horizontal cases is higher than the thinning base case (N_1). Vertical cases of viscoelastic thickening polymer have lower recovery than the thinning base case.

4.2. Results Analysis and Discussion

This section presents and discusses the results obtained from the three field cases: Matzen field, Daqing field, and Pelican Lake field. Results of several main parameters that were investigated in this study and their effect on the injector well horizontal length will be presented.

4.2.1. Viscosity Ratio

The viscosity ratio is defined as the polymer viscosity divided by the oil viscosity, Eqn 4.1.

$$\text{Viscosity Ratio} = \frac{\mu_p}{\mu_o} \quad (4.1)$$

For the actual three cases, Daqing field had the highest favorable viscosity ratio of 30 followed by Matzen field with a favorable viscosity ratio of 5 and then by Pelican Lake field which is attributed with the least favorable viscosity ration of 0.01 due to its high oil viscosity. Simulation results supported this classification as **Table 4.1** below shows that Daqing field had the highest oil recovery followed by Matzen and Pelican Lake fields respectively. Note that the results presented have the same thickening index ($N_2 = 1.173$) to maintain consistency when comparing the cases. The low value of Pelican Lake is due to the high viscosity of the oil in comparison with the other two fields which have almost similar oil viscosities. A reason for the high recovery of Daqing in comparison with the other two fields is the better sweep efficiency caused by the high polymer viscosity that results in the polymer flow in the reservoir at relatively lower velocities which helps in contacting more oil and increasing the recovery.

Table 4.1: Comparison between viscosity ratio of the three field cases

Field	Viscosity ratio	Favorability	Oil Recovery
Daqing	300cP/10cP ≈ 30	Highly Favorable	2,557,628
Matzen	10cP/19cP ≈ 0.5	Favorable	2,058,308.6
Pelican Lake	30cP/3000cP ≈ 0.01	Least Favorable	23,996.09

The viscosity ratio was also varied within each case as two additional polymer viscosities for each case as assumed. As discussed previously, note that the Pelican Lake highest proposed polymer viscosity 300 cP was not able to run due to the high oil and polymer viscosity together. Nonetheless, a similar trend was observed within each case as the higher viscosity ratio which is more favorable produced more oil as illustrated by **Table 4.2**. Although higher oil recovery is realized by more favorable viscosity ratio, no significant difference in recovery is noticed. This observation can be attributed to the relatively small area of the reservoir which is considered a small pilot area. It is expected to notice more significant difference in recovery should the reservoir area be increased.

Table 4.2: Comparison between viscosity ratio within each field case

Field	Viscosity ratio	Favorability	Oil Recovery (BBL)
Daqing	$300\text{cP}/10\text{cP} \approx 30$	Highly Favorable	2,543,457
	$30\text{cP}/10\text{cP} \approx 3$	Favorable	2,551,999.5
	$3\text{cP}/10\text{cP} \approx 0.3$	Least Favorable	2,557,628
Matzen	$100\text{cP}/19\text{cP} \approx 5$	Highly Favorable	2,073,076.5
	$10\text{cP}/19\text{cP} \approx 0.5$	Favorable	2,058,308.6
	$2.5\text{cP}/19\text{cP} \approx 0.1$	Least Favorable	2,054,899
Pelican Lake	$30\text{cP}/3000\text{cP} \approx 0.01$	More Favorable	23,996.09
	$3\text{cP}/3000\text{cP} \approx 0.001$	Least Favorable	23,787.18

4.2.2. Polymer Viscosity

This part will discuss the relationship observed between the polymer viscosity and the optimum required horizontal length to cancel the negative effect of viscoelasticity. This part considers only optimizing the injectivity of the injector without taking the total oil recovery into consideration. Note that the results presented have the same thickening index ($N_2 = 1.925$) to maintain consistency when comparing the cases.

It was noticed that the higher polymer recovery required a lengthier horizontal well to relief the high injection pressure and improve the injectivity to a value which is similar or lightly higher than base viscous polymer for each case. **Table 4.3** highlights the results obtained from the simulation of the three filed cases.

Table 4.3: Injector horizontal well length for each field case at different polymer viscosities

Field	Polymer Viscosity	Optimal Injector Horizontal Length (ft)
Daqing	300cP	1300
	30cP	700
	3cP	200
Matzen	100cP	1600
	10cP	500
	2.5cP	200
Pelican Lake	30cP	300
	3cP	200

It is worth noting that the Pelican Lake field required shorter horizontal length to mitigate the injectivity issue. Although the injectivity is being improved, lower oil is being recovered due the high viscosity of Pelican Lake oil that is 3000 cP. This high oil viscosity requires more cross-sectional area to compensate for the low velocity rate. Moreover, viscous polymer itself generated higher pressure due to high oil viscosity. Since we based our optimization with regard to the high injection pressure created by vertical well case, this is the case. It will be interesting to compare with the water-injectivity case or the real case injectivity to see the required horizontal well-length in Pelican Lake case. Thus, longer horizontal lengths are used in reality to produce more oil and make the case economic. However, the aim of this study was to resolve negative aspects of viscoelasticity only by looking at injectivity, without considering economics or oil recovery. Furthermore, this thesis did not address optimizing injectivity while resolving viscosity's negative aspects.

In addition, horizontal well length results of the actual case polymer viscosity for Matzen field (10 cP) was matching the ones used in real field application of 500-600 ft (Van Laer, 2016; Zechner et al., 2014). The polymer system used in the actual Matzen polymer flooding project consisted of 2000 ppm HPAM with a 10 cP polymer viscosity. The polymer system used in this work is of similar properties with 10 cP viscoelastic polymer using multiple viscoelasticity values (shear thickening index) which encompassed the actual polymer system design for Matzen field polymer project. The optimal required horizontal length was increasing as the viscoelasticity was increased.

4.2.3. Polymer Viscoelasticity

The polymer viscoelasticity is an important property which influences the behavior of the polymer at different shear rates near and away from the injector well. This research

varied the polymer viscoelasticity from low ($N_2 = 1.173$) to medium ($N_2 = 1.6554$) to high ($N_2 = 1.925$) for each polymer viscosity for each field case. For instance, as illustrated by **Table 4.4** for Matzen field case, longer horizontal length was required for higher viscoelasticity at high polymer viscosity. However, the viscoelasticity effect on the injector horizontal length becomes insignificant at low polymer viscosity such as the case of 2.5 cP. This is due to the effect of relatively low zero shear rate viscosity as thickening behavior gets amplified only when the viscosity itself is high. The polymer data provided in **Appendix A** showcase the relation between viscosity and viscoelasticity. The other field cases have similar viscoelasticity effect trend at low viscosity.

Table 4.4: Effect of polymer viscoelasticity on horizontal well length (Matzen)

Polymer Viscosity	Polymer Viscoelasticity	Injector Horizontal Length
2.5	1.173	200
2.5	1.6554	200
2.5	1.925	200
10	1.173	200
10	1.6554	400
10	1.925	500
100	1.173	400
100	1.6554	900
100	1.925	1,600

The polymer viscoelasticity also affects the total oil recovery. More oil is recovered as the polymer viscoelasticity is increased, **Table 4.5**. The high viscoelasticity results in an increase in the polymer viscoelasticity which helps to improve the sweep efficiency and

hence recover more oil. The increase in the oil recovery as the polymer viscosities and viscoelasticity are increased might seem small and not worth the effort. However, the reason for this is the relatively small field scale that was considered, which is a pilot project area. Increasing the reservoir area will show larger difference in oil recovery between the cases. This oil recovery might be underestimated since the simulator can not capture the microscopic oil recovery contribution from polymer viscoelasticity which will be pursued later as an enhancement of this work.

Table 4.5: Effect of polymer viscoelasticity on oil recovery (Matzen)

Polymer Viscosity	Polymer Viscoelasticity	Oil Recovery
		[BBL]
2.5	1.173	2,054,826.4
2.5	1.6554	2,054,864.5
2.5	1.925	2,054,899
10	1.173	2,055,153.5
10	1.6554	2,057,051.9
10	1.925	2,058,308.6
100	1.173	2,062,497.8
100	1.6554	2,069,751.9
100	1.925	2,073,076.5

4.2.4. Injector Horizontal Length

The injector horizontal length effect on total oil recovery was studied. As the horizontal length of the injector increases, the oil recovery increases due to larger sweep which is closely approaching a piston-like injection, see **Table 4.6** which shows the results

for Matzen 2.5 cP and $N_2 = 1.172$ case. The staggered line injection pattern that was selected at the start of this work makes the increase the injector horizontal length more favorable towards the oil recovery.

Table 4.6: Effect of injector well horizontal length on oil recovery (Matzen 2.5 cP $N_2 = 1.173$)

Field	Polymer Viscosity	Index	Horizontal Length [ft]	Oil Recovery [bbl]
Matzen	2.5	$N_2 = 1.173$	0	2,498,981.3
Matzen	2.5	$N_2 = 1.173$	200	2,499,300.8
Matzen	2.5	$N_2 = 1.173$	300	2,499,942.3
Matzen	2.5	$N_2 = 1.173$	400	2,500,709.0
Matzen	2.5	$N_2 = 1.173$	500	2,501,525.8
Matzen	2.5	$N_2 = 1.173$	600	2,502,331.5
Matzen	2.5	$N_2 = 1.173$	700	2,503,218.3
Matzen	2.5	$N_2 = 1.173$	800	2,504,061.8
Matzen	2.5	$N_2 = 1.173$	900	2,504,874.8
Matzen	2.5	$N_2 = 1.173$	1,000	2,505,742.3

However, one needs to note that drilling unnecessary long horizontal length might kill the viscoelastic effect which can contribute to additional microscopic recovery. Nonetheless, this is an area of investigation where developing a simulator that could

precisely predict the microscopic recovery by honoring the viscoelastic effect is under continuous research.

4.2.5. Oil Producer Well Orientation

In this work, the simulation scenarios for all field cases were run with a vertical producer and then repeated by transforming this producer to a horizontal well of 1000 ft. Results indicated that the producer orientation does not have a big influence on the optimum injector horizontal length. **Table 4.7** compares the horizontal wells length obtained for the vertical and horizontal producer orientations for Daqing cases.

Table 4.7: Injector horizontal well length is similar for both vertical and horizontal oil producer simulation cases (Daqing field)

Polymer Viscosity	Polymer Viscoelasticity	Vertical Producer Injector Horizontal Length	Horizontal Producer Injector Horizontal Length
3	1.173	200	200
3	1.6554	200	200
3	1.925	200	200
30	1.173	200	200
30	1.6554	500	500
30	1.925	700	700
300	1.173	500	500
300	1.6554	800	800
300	1.925	1,300	1,300

Similar result was noticed for all field cases, where the same optimum horizontal length was required for both simulation scenarios using vertical and horizontal producers.

This result is vital for Daqing field as the field produces through vertical producers (Ezeh et al., 2021b). Thus, the approach followed in this thesis work for optimizing the injector horizontal well works for Daqing field too.

This being said, the major difference of changing the producer orientation was noticed on the oil recovery. Horizontal oil producers recovered more oil than the vertical producers as shown by **Table 4.8**. Again, this recovery might be underestimated since the simulator can not capture the microscopic oil recovery. This reason could also explain the small difference in recovery between both orientations.

Table 4.8: Oil recovery from horizontal producers is higher than vertical producers (Daqing field)

Polymer Viscosity	Polymer Viscoelasticity	Vertical Producer Oil Recovery [BBL]	Horizontal Producer Oil Recovery [BBL]
3	1.173	2,543,453.8	2,610,639.8
3	1.6554	2,543,462.3	2,610,694.8
3	1.925	2,543,749.3	2,610,775.8
30	1.173	2,547,750.8	2,613,527.5
30	1.6554	2,550,615	2,617,676.8
30	1.925	2,551,999.5	2,618,574
300	1.173	2,553,799	2,617,726.5
300	1.6554	2,557,119.3	2,619,674.8
300	1.925	2,557,628	2,619,739

4.2.6. Simulation Scenario with Economic Analysis

The first case of this work considered optimizing the injector horizontal well length based on the injectivity alone. However, the second case took economics into consideration. It was noticed that increasing the polymer viscosity and viscoelasticity resulted in higher oil recovery and hence more profit, see **Table 4.9**. This is due to higher sweep efficiency resulting from the higher polymer viscosity.

Table 4.9: Oil recovery increase by increasing the polymer viscosity and viscoelasticity (Matzen). The cases were profitable for all oil price ranges ranging from low (\$30/bbl), medium(\$50/bbl), and high (\$100/bbl).

Polymer Viscosity	Polymer Viscoelasticity	Oil Recovery [BBL]	Net Profit [\$] \$30/bbl	Net Profit [\$] \$50/bbl	Net Profit [\$] \$100/bbl
2.5	1.173	2,054,826.4	34,224,986	75,321,514	178,062,834
2.5	1.6554	2,054,864.5	34,258,504	75,355,794	178,099,019
2.5	1.925	2,054,899	34,291,807	75,389,787	178,134,737
10	1.173	2,055,153.5	34,071,102	75,174,172	177,931,847
10	1.6554	2,057,051.9	34,102,533	75,243,571	178,096,166
10	1.925	2,058,308.6	34,176,217	75,342,389	178,257,819
100	1.173	2,062,497.8	33,681,003	74,930,959	178,055,849
100	1.6554	2,069,751.9	33,789,316	75,184,354	178,671,949
100	1.925	2,073,076.5	33,812,838	75,274,368	178,928,193

However, there is a limit to increasing the viscoelasticity as it would require larger horizontal well length to remove the negative viscoelastic effect. Drilling longer horizontal wells will help recover more oil as suggested by **Table 4.6**, but drilling very long horizontal lengths might kill the additional microscopic recovery caused by viscoelasticity. Since the

simulator has a limitation in honoring and capturing the viscoelastic effect, this optimization based on microscopic recovery and polymer viscoelasticity was not conducted and is to be pursued for future work.

4.2.7. Field Case Simulation Results Summary

Multiple scenarios were simulated for each field case by varying the polymer viscosity, polymer viscoelasticity, and producer well orientation. The following figures and tables present a summary of the obtained results based on optimizing the injectivity alone. **Figure 4.8-4.12** present the injectivity and injection pressure for one polymer viscosity case for each field. Other cases can be found in Appendix B. **Table 4.10-4.12** below provide a summary of the optimized injector horizontal well lengths for each field case.

Matzen Field:

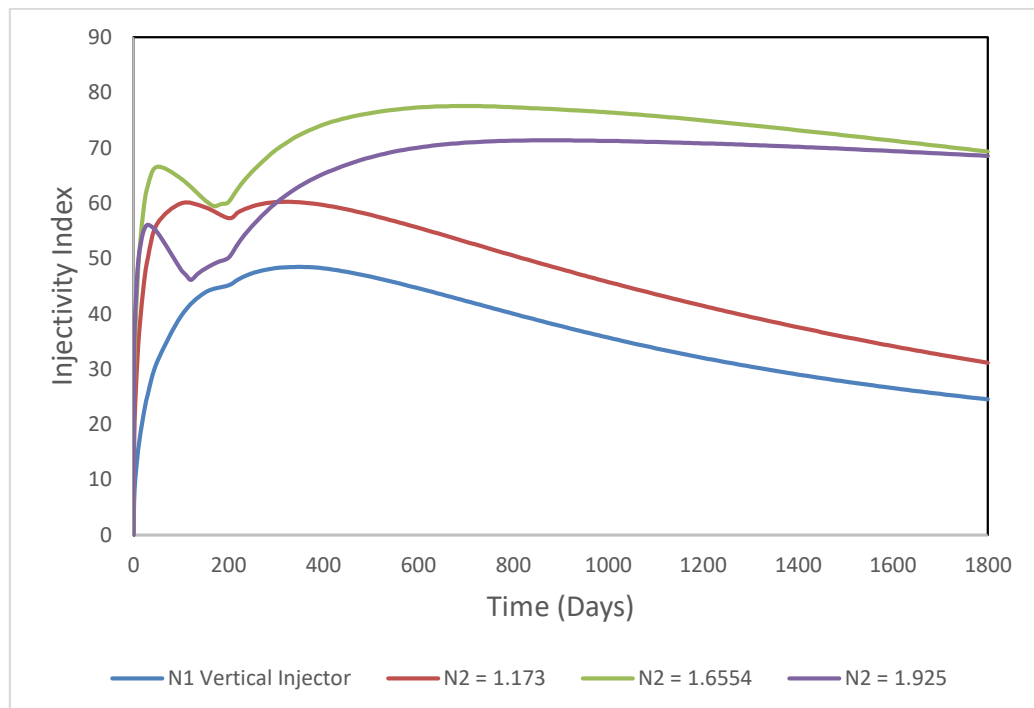


Figure 4.8: Matzen field optimized injectivity for 10 cP polymer viscosity

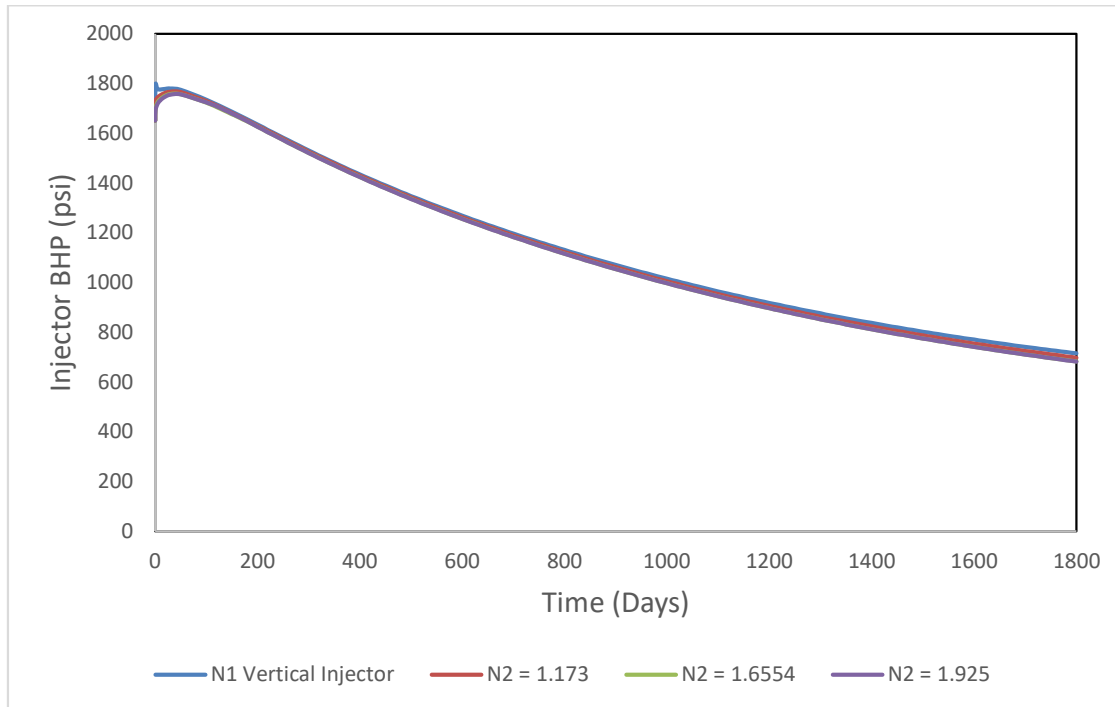


Figure 4.9: Matzen field optimized injection BHP for 10 cP polymer viscosity

Table 4.10: Matzen field optimized injector horizontal length summary

Polymer Viscosity	Polymer Viscoelasticity	Injector Horizontal Length
2.5	1.173	200
2.5	1.6554	200
2.5	1.925	200
10	1.173	200
10	1.6554	400
10	1.925	500
100	1.173	400
100	1.6554	900
100	1.925	1,600

Daqing Field:

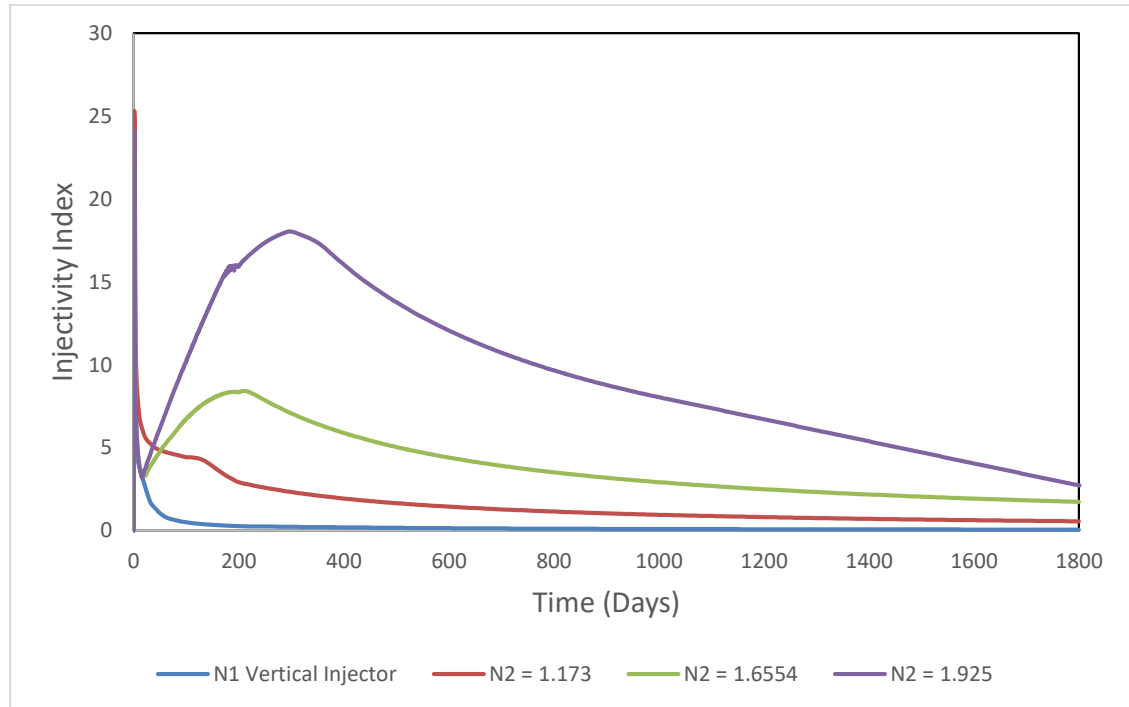


Figure 4.10: Daqing field optimized injectivity for 300 cP polymer viscosity

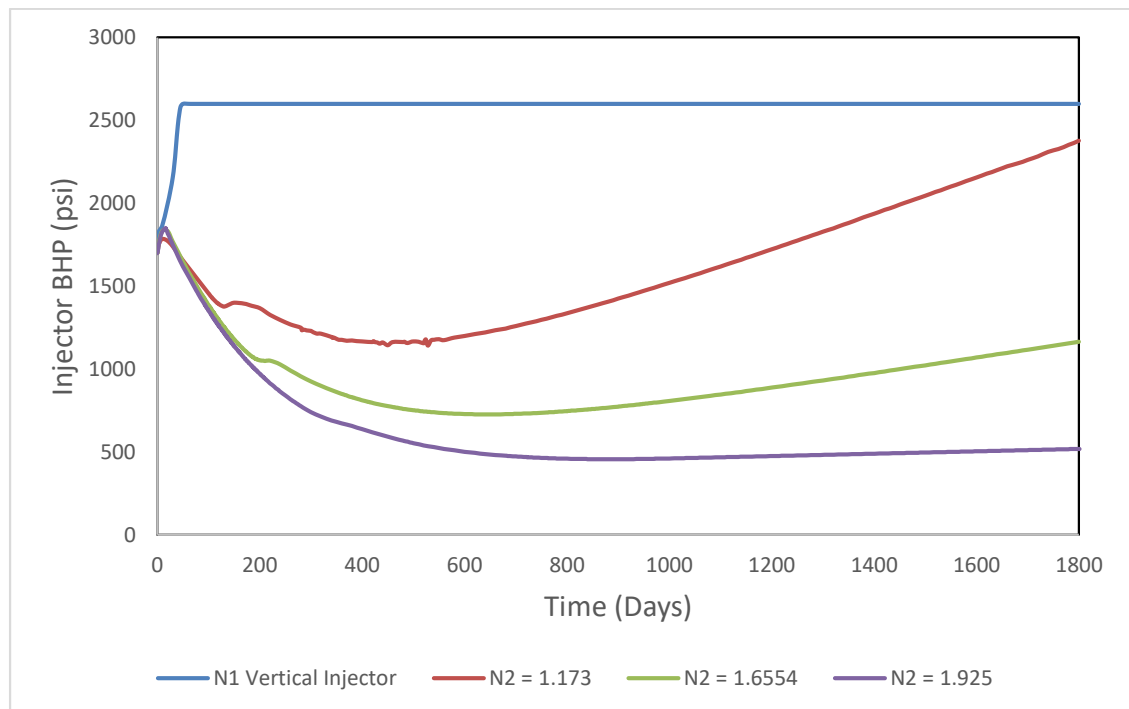


Figure 4.11: Daqing field optimized injection BHP for 300 cP polymer viscosity

Table 4.11: Daqing field optimized injector horizontal length summary

Polymer Viscosity	Polymer Viscoelasticity	Injector Horizontal Length
3	1.173	200
3	1.6554	200
3	1.925	200
30	1.173	200
30	1.6554	500
30	1.925	700
300	1.173	500
300	1.6554	800
300	1.925	1,300

Pelican Lake Field:

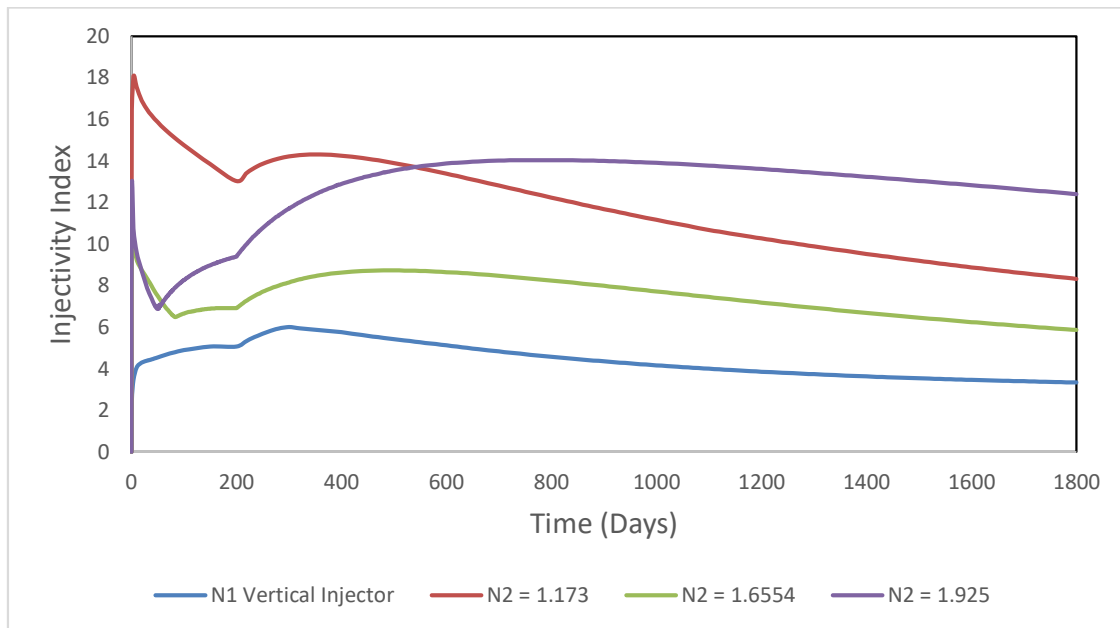


Figure 4.12: Pelican Lake field optimized injectivity for 30 cP polymer viscosity

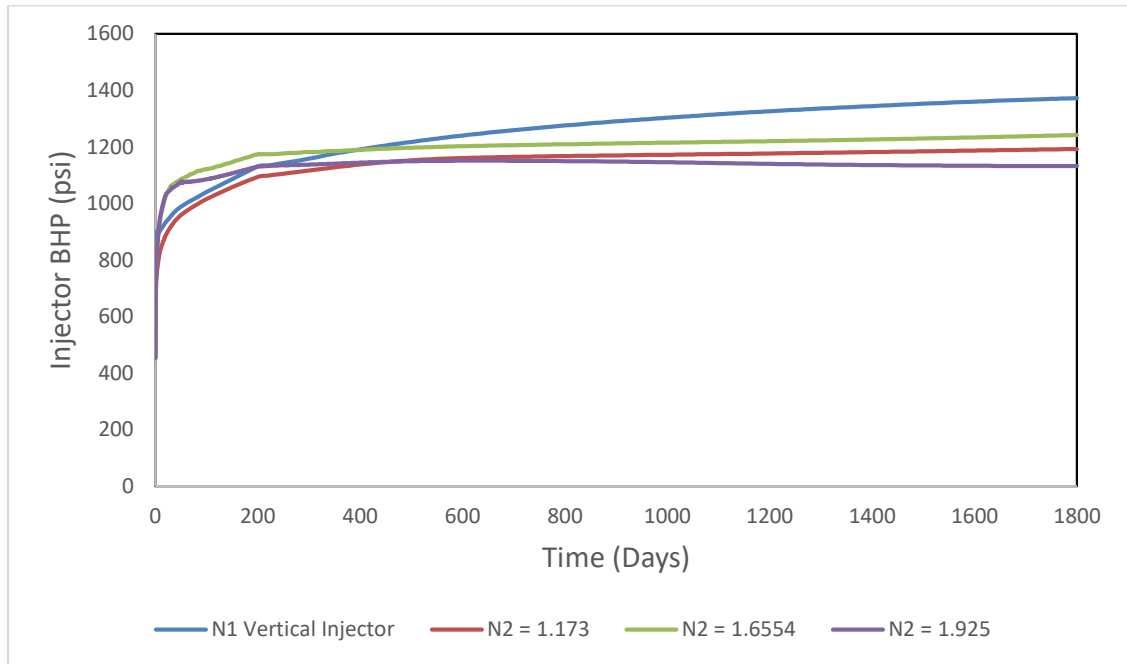


Figure 4.13: Pelican Lake field optimized injection BHP for 300 cP polymer viscosity

Table 4.12: Pelican Lake field optimized injector horizontal length summary

Polymer Viscosity	Polymer Viscoelasticity	Injector Horizontal Length
3	1.173	200
3	1.6554	200
3	1.925	200
30	1.173	200
30	1.6554	500
30	1.925	700
300	1.173	500
300	1.6554	800
300	1.925	1,300

4.2.8. Developed Correlation Models

Correlation models were developed for each field to predict the optimum horizontal well length. The user needs to feed the correlation with the polymer viscosity and viscoelasticity to get the recommended injector horizontal well length that would remove the negative effect of viscoelasticity. Since the results of the vertical and horizontal producer cases are similar in each field case, one correlation was developed field covering both producer orientations. It is worth noting that those correlations correspond to the three fields of interest. If the user wants a correlation that suits their reservoir, they need to follow this work methodology to develop their own correlation based on the reservoir properties and polymer data.

Matzen Correlation Model:

$$L = 202.163 + \left(\left(0.5587 - \cos \left((-0.5985 + \mu_p) * \tan(0.08207 * N_2^2) - 0.1038 \right) \right) * (3.759 * (\tan(\mu_p - 0.1577 + \tan(\mu_p)) + \mu_p + \tan(-1.1802 + N_2)) + 148.542) \right) \quad (4.2)$$

$$R^2 = 1$$

Where:

L : Injector horizontal well length (ft)

μ_p : Polymer Viscosity (cP)

N_2 : Polymer Viscoelasticity (Thickening Index)

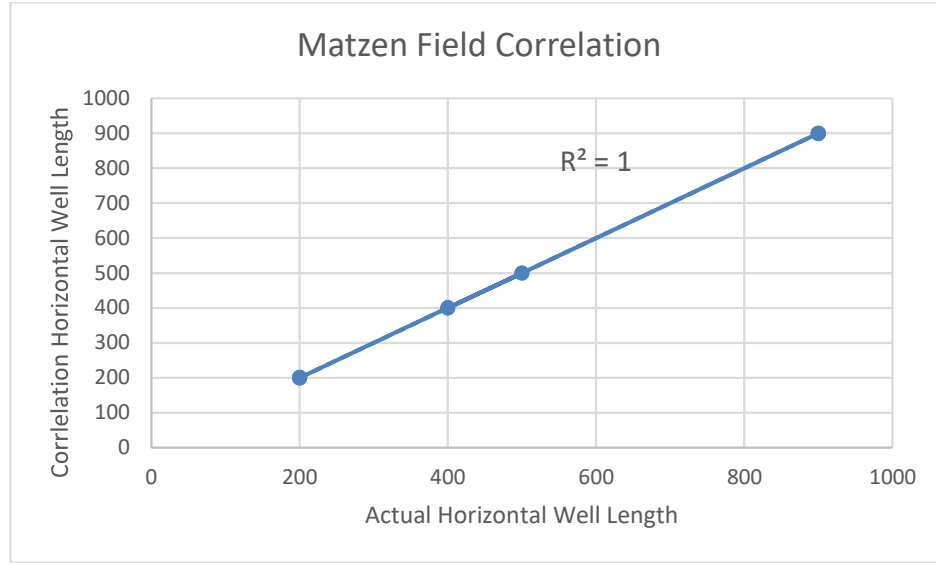


Figure 4.14: Matzen field actual optimized horizontal length date vs correlation data

Daqing Correlation Model:

$$L = \cos \left(\left(\mu_p + \left(14.534 - 2.987 * \sin \left((1.255 + \mu_p) * (\cos(N_2) * (-0.01032 - N_2) \right) \right) \right) * \left(\frac{0.09938}{N_2} \right) * (1.0034 + N_2) \right) * \left(266.004 + 0.503 * \mu_p - (2.924 - N_2^2) \right) + 418.827 \right) \quad (4.3)$$

$$R^2 = 1$$

Where:

L : Injector horizontal well length (ft)

μ_p : Polymer Viscosity (cP)

N_2 : Polymer Viscoelasticity (Thickening Index)

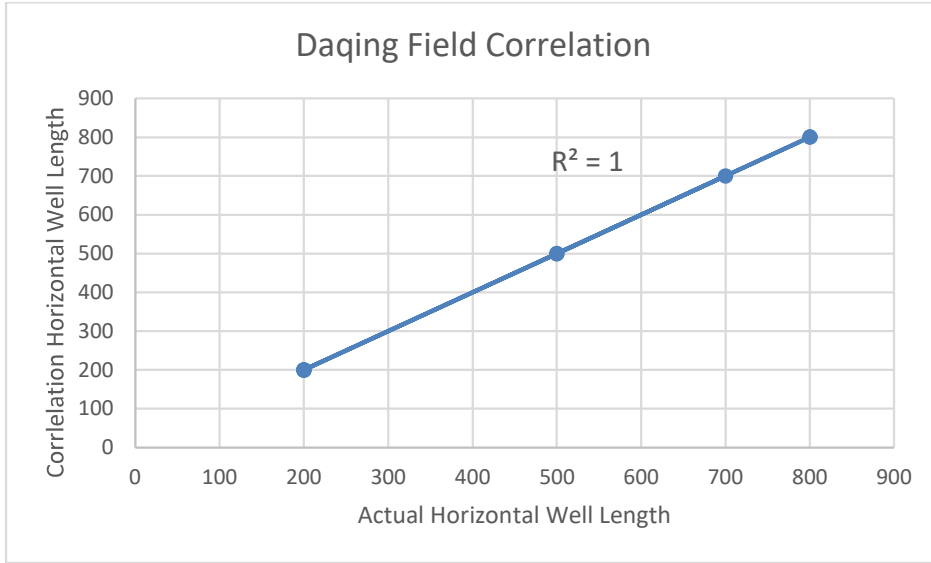


Figure 4.15: Daqing field actual optimized horizontal length date vs correlation data

Pelican Lake Correlation Model:

$$LL = 200 + \left(\left((1.002 * (N_2 - 0.8829))^{\mu_p} - ((-0.000943) * (1.184 - N_2)) \right) * \left(\left(\frac{-1.438}{\mu_p} \right) + \mu_p - 2.5203 \right) \right) \quad (4.4)$$

$$R^2 = 1$$

Where:

L : Injector horizontal well length (ft)

μ_p : Polymer Viscosity (cP)

N_2 : Polymer Viscoelasticity (Thickening Index)

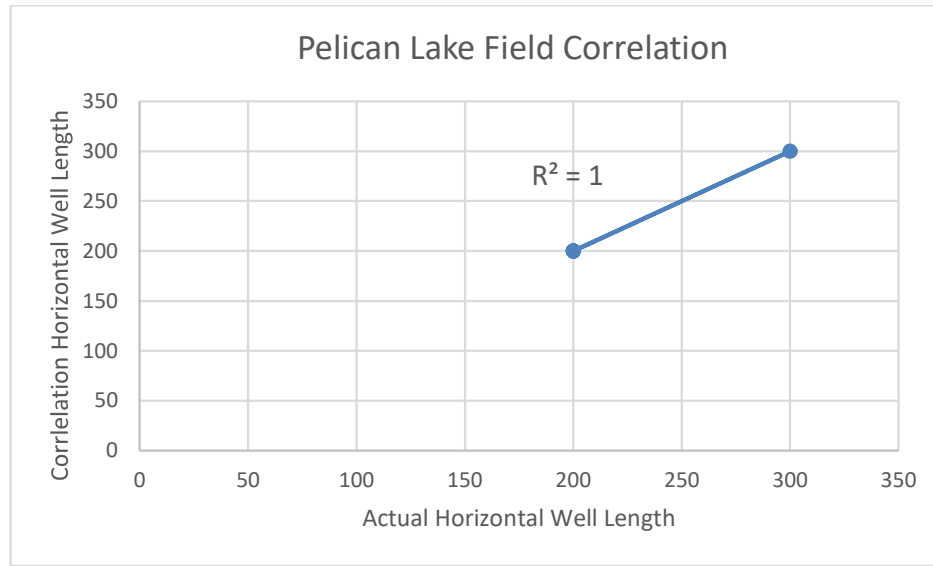


Figure 4.16: Pelican Lake field actual optimized horizontal length date vs correlation data

4.2.9. Recommendations and Future Work

The correlation models developed in this work are for the aforementioned three field cases. If the users have a different field, they need to develop their own correlation model using their reservoir properties and polymer data.

This work could not investigate the viscoelastic effect on the microscopic recovery due to a limitation in the simulator. Future enhancement of this work will be using other software such as UTCHEM that are under enhancement to improve its capability to honor the viscoelastic effect and take the microscopic recovery into consideration to improve the optimization of the injector horizontal well length during viscoelastic polymer floods.

4.2.10. Conclusion

Simulation cases were created using thinning and thickening polymers to determine the optimum horizontal length that lower the injection pressure attributed to the viscoelastic behavior of synthetic polymer and generate an injectivity value comparable to the viscous case. All simulated cases were developed using a staggered line pattern. Vertical injectors experience high pressure drop to viscoelastic polymer thickening behavior. High polymer viscosity and viscoelasticity causes more severe pressure drop but higher total recovery due to better sweep. Horizontal wells got rid of the negative aspects of viscoelasticity by giving a comparable or slightly higher injectivity provided by viscous polymer with vertical injectors. Further, the required horizontal length increases as the polymer elasticity (thickening index) increases. At very low polymer viscosity, the polymer viscoelasticity is insignificant. A future enhancement for this work is to consider the viscoelastic behavior in Sor reduction as the simulator might have underestimated the total recovery due to not having the ability to account for the microscopic recovery by honoring the viscoelastic effect of polymer. The methodology presented can be used by engineers in predicting required horizontal injector length to minimize the injectivity issues by driving an equation using their own field parameters and wells specific injection pattern.

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Appendix A

In this appendix, the polymer thickening data for each field case will be presented.

➤ Matzen Field:

- Matzen field **2.5 cP** polymer data:

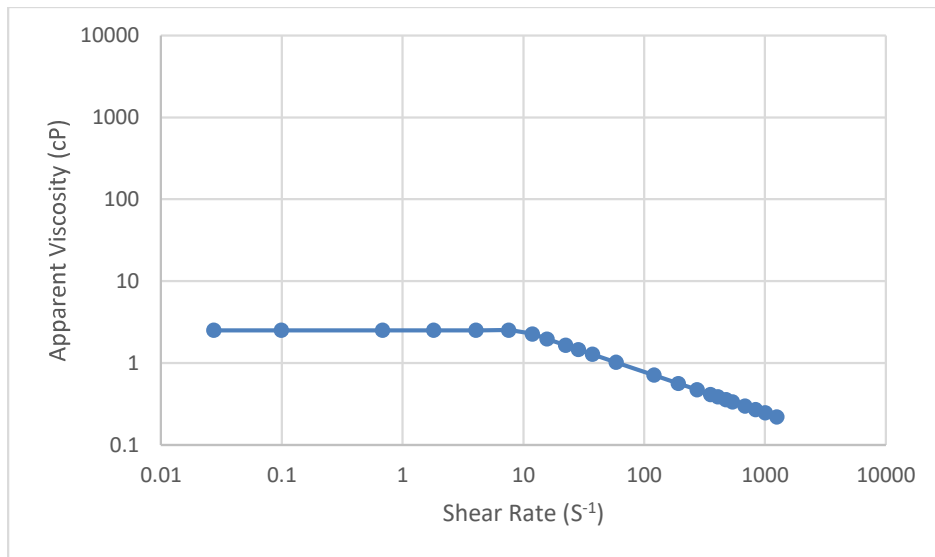


Figure A.1: Matzen field 2.5 cP polymer shear thinning data set ($N1 = 0.5$)

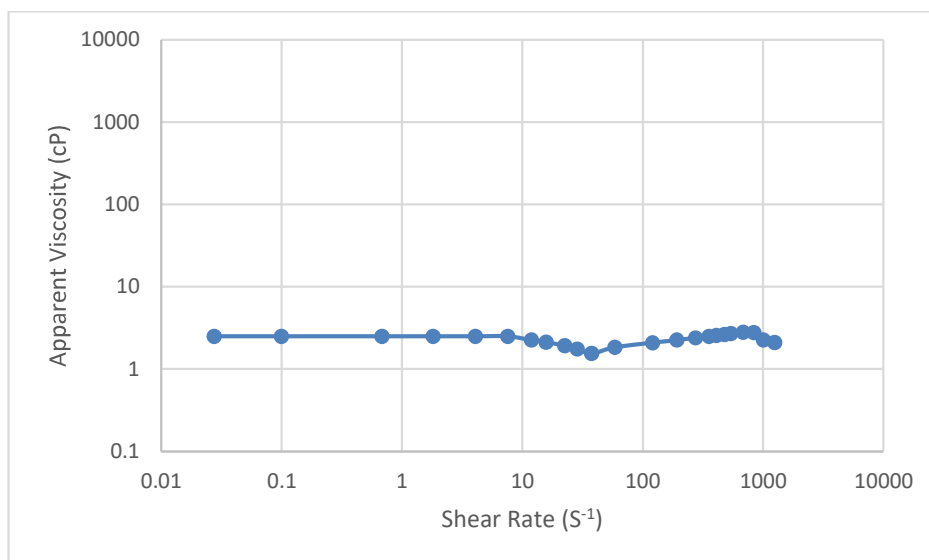


Figure A.2: Matzen field 2.5 cP polymer low shear thickening data set ($N_2 = 1.173$)

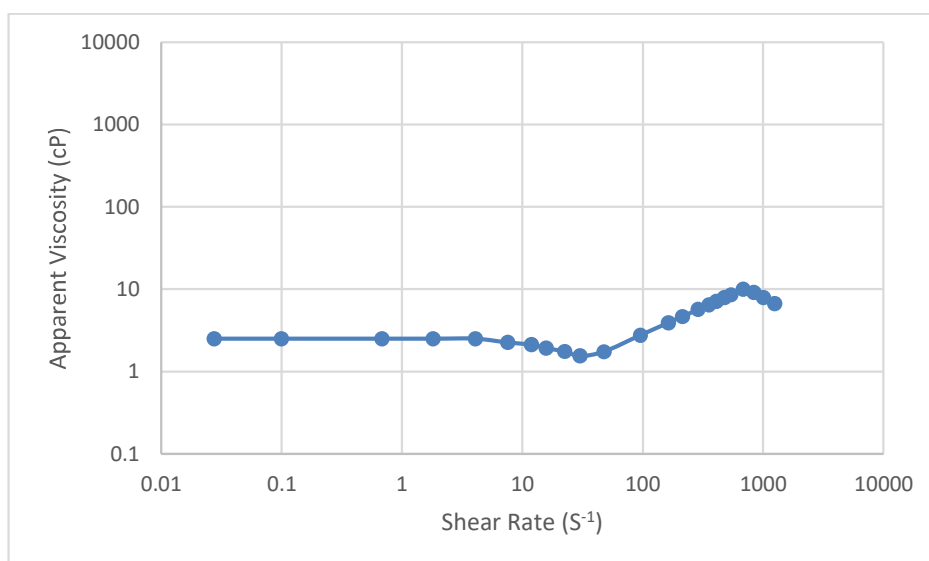


Figure A.3: Matzen field 2.5 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

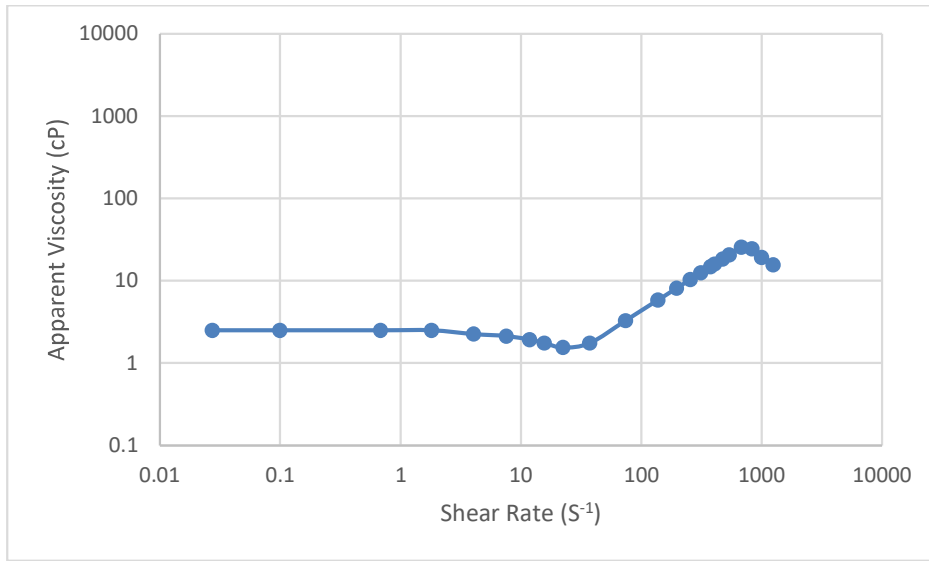


Figure A.4: Matzen field 2.5 cP polymer high shear thickening data set ($N_2 = 1.925$)

- Matzen field **10 cP** polymer data:

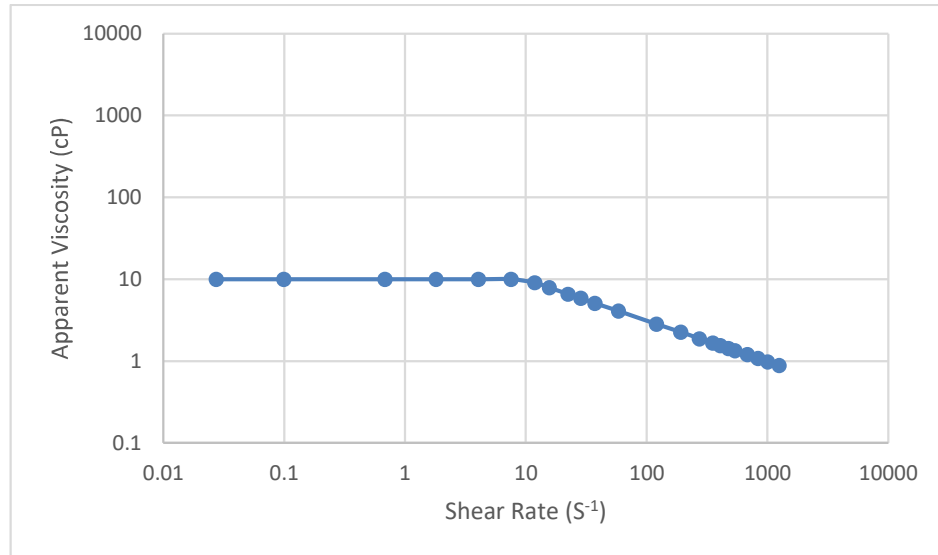


Figure A.5: Matzen field 10 cP polymer shear thinning data set ($N_1 = 0.5$)

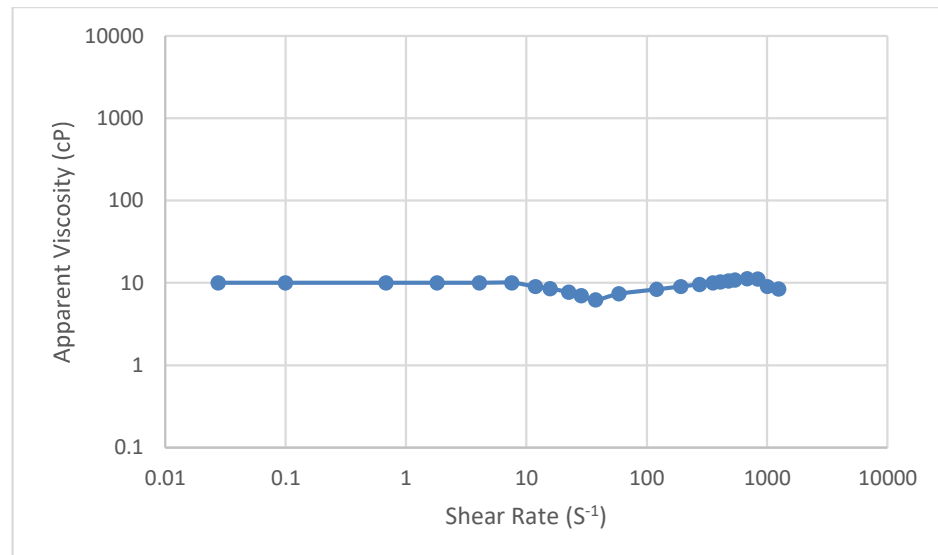


Figure A.6: Matzen field 10 cP polymer low shear thickening data set ($N_2 = 1.173$)

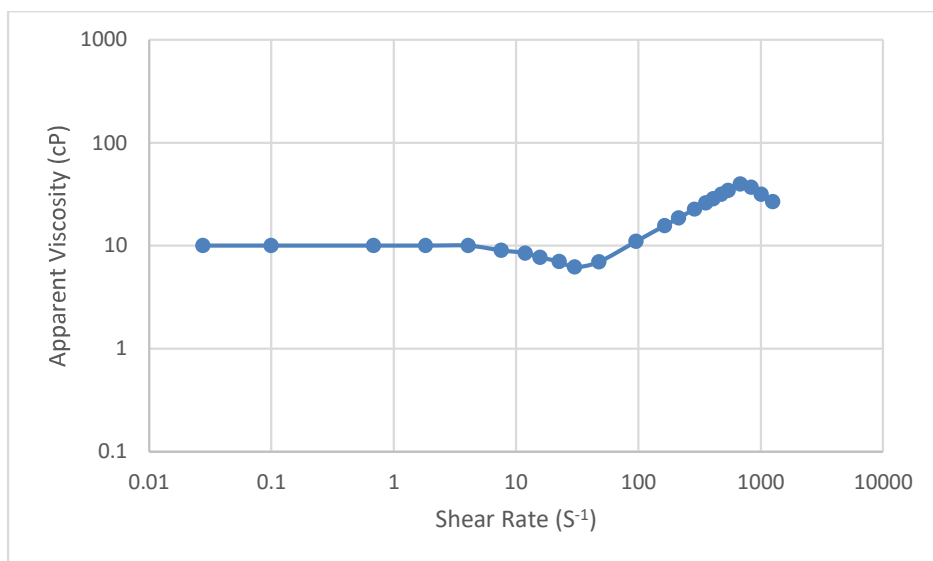


Figure A.7: Matzen field 10 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

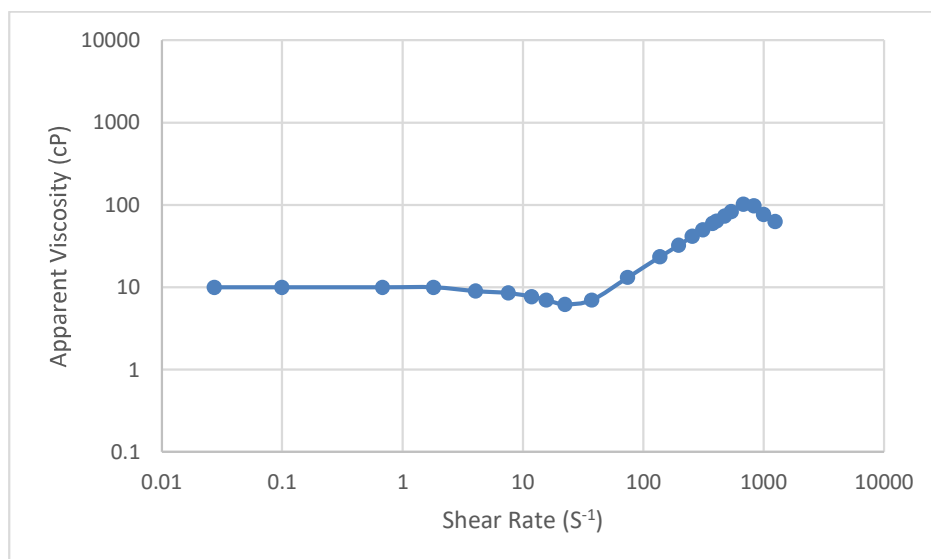


Figure A.8: Matzen field 10 cP polymer high shear thickening data set ($N_2 = 1.925$)

- [Matzen field **100 cP** polymer data:

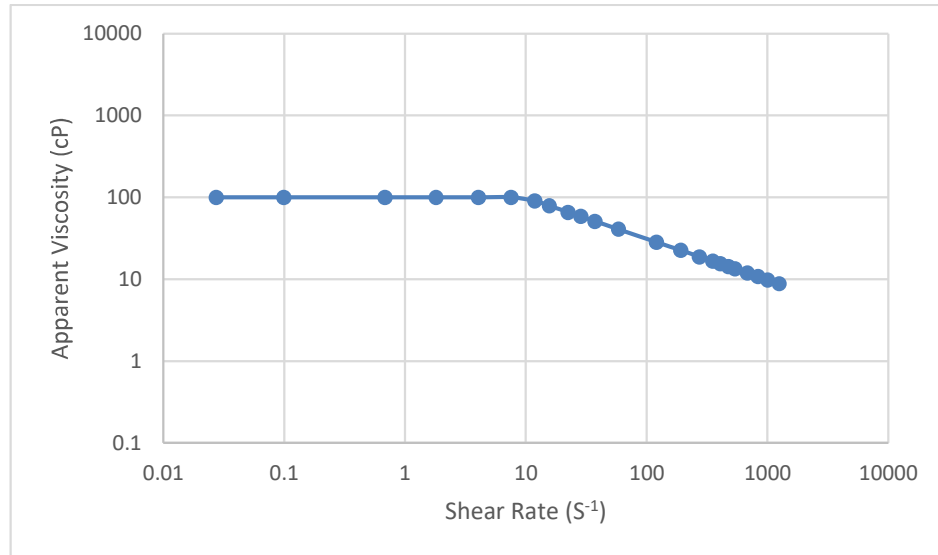


Figure A.9: Matzen field 100 cP polymer shear thinning data set ($N_1 = 0.5$)

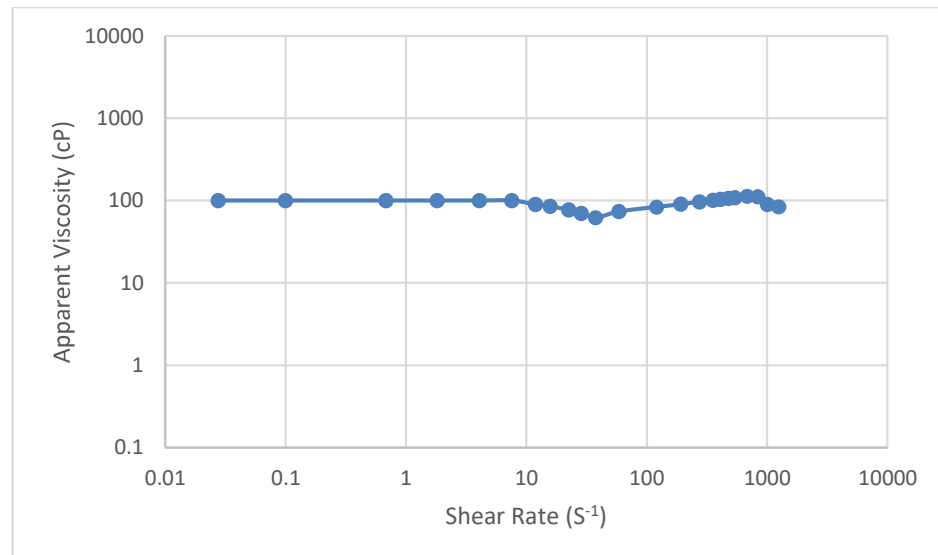


Figure A.10: Matzen field 100 cP polymer low shear thickening data set ($N_2 = 1.173$)

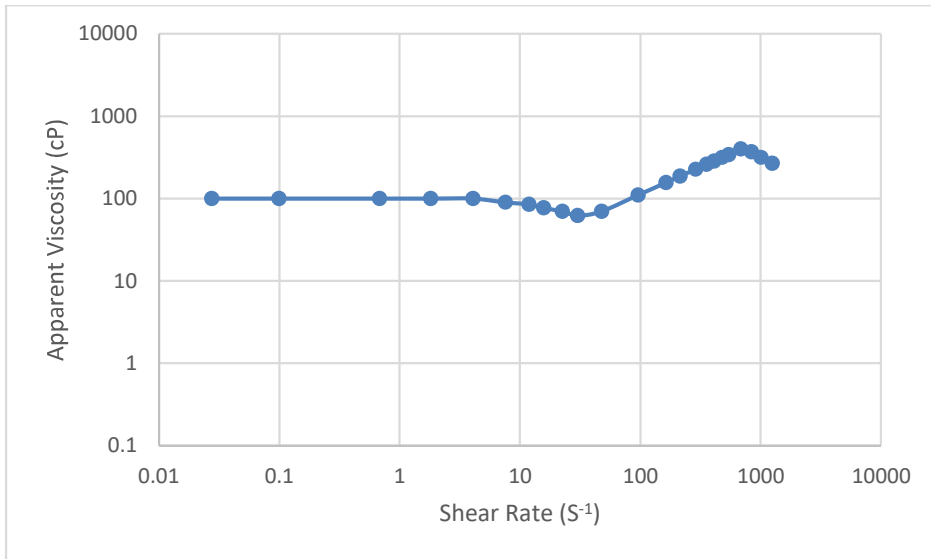


Figure A.11: Matzen field 100 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

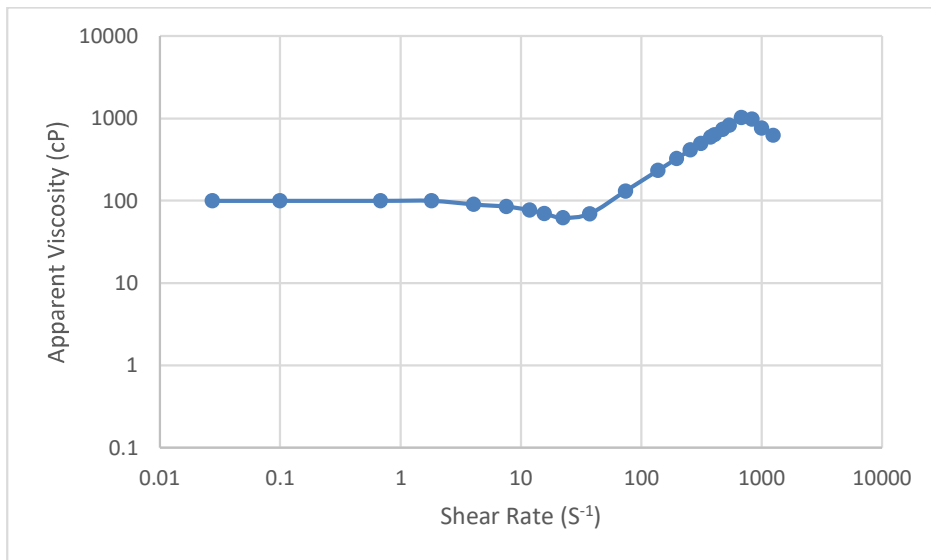


Figure A.12: Matzen field 100 cP polymer high shear thickening data set ($N_2 = 1.925$)

➤ **Daqing Field:**

- Daqing field 3 cP polymer data:

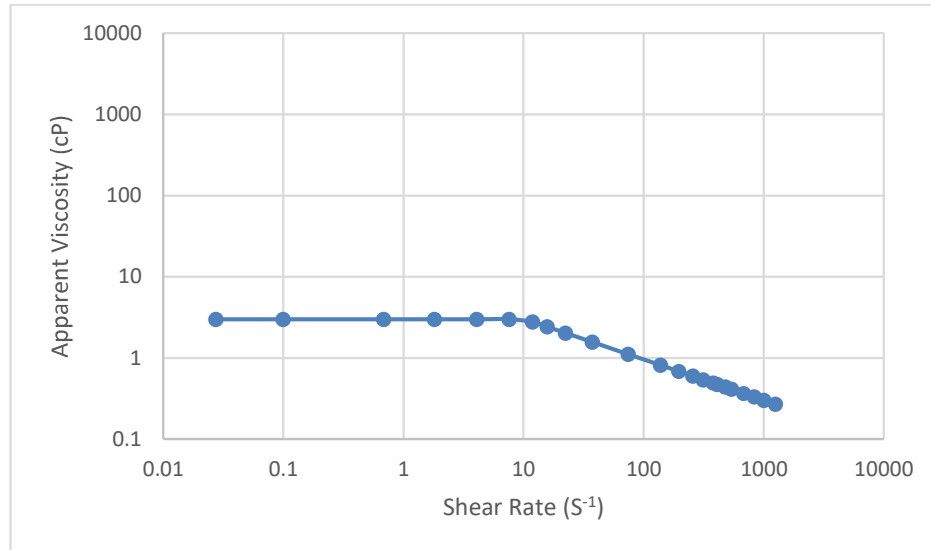


Figure A.13: Daqing field 3 cP polymer shear thinning data set ($N_1 = 0.5$)

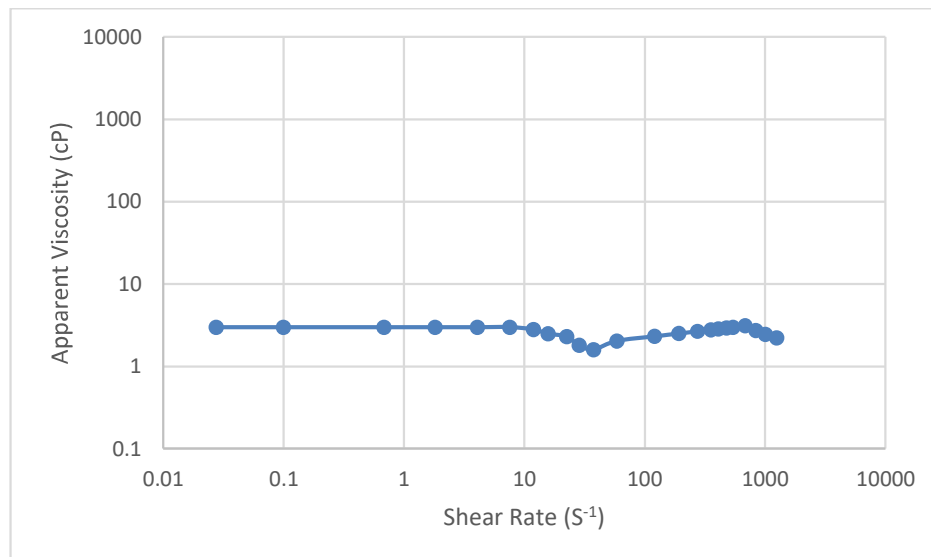


Figure A.14: Daqing field 3 cP polymer low shear thickening data set ($N_2 = 1.173$)

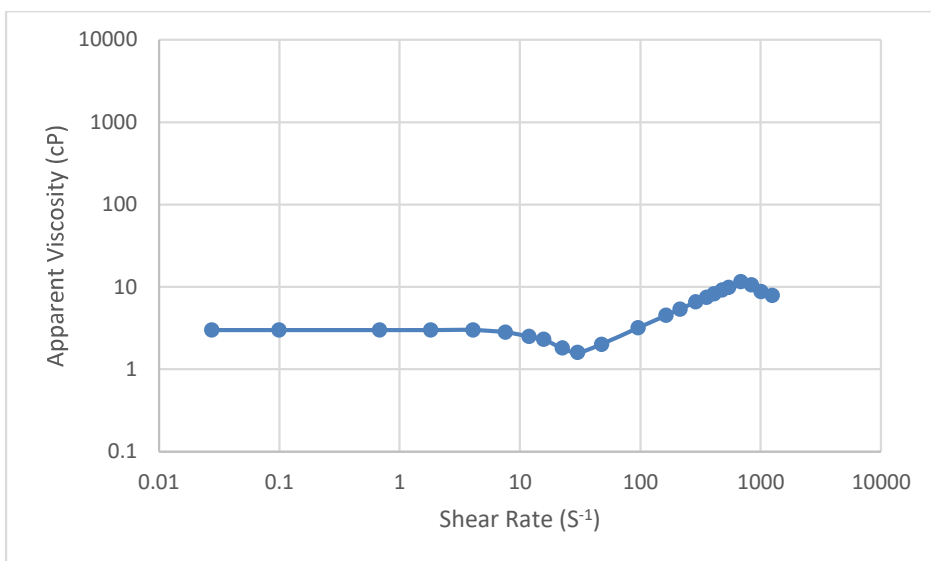


Figure A.15: Daqing field 3 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

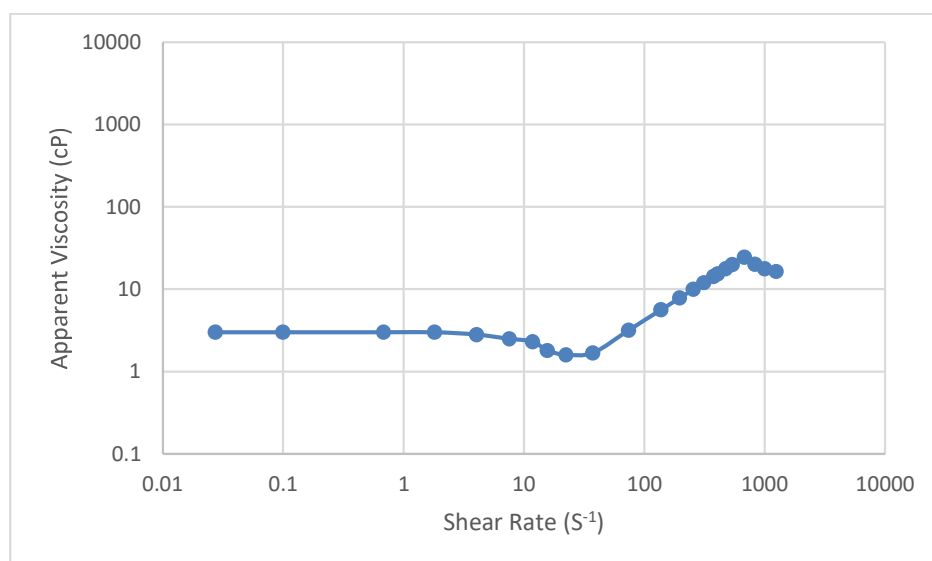


Figure A.16: Daqing field 3 cP polymer high shear thickening data set ($N_2 = 1.925$)

- Daqing field 30 cP polymer data:

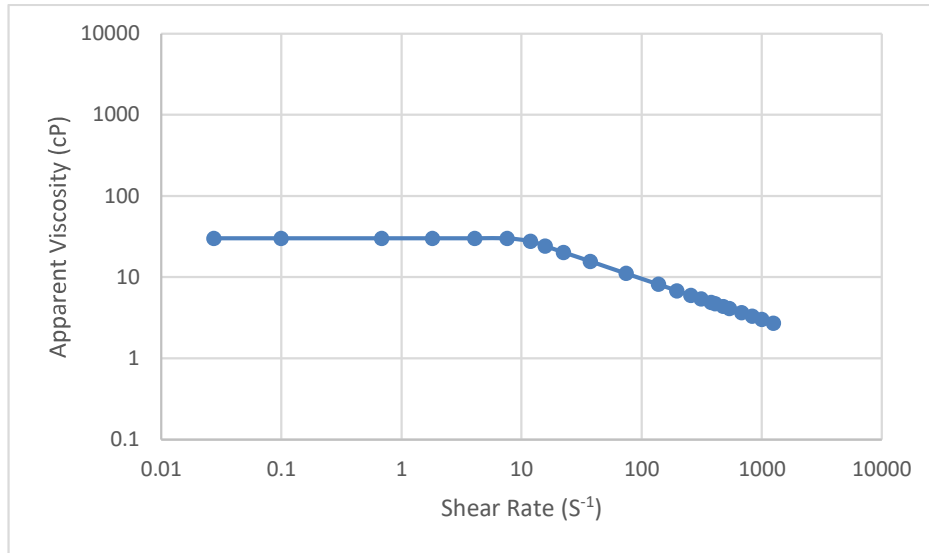


Figure A.17: Daqing field 30 cP polymer shear thinning data set ($N_1 = 0.5$)

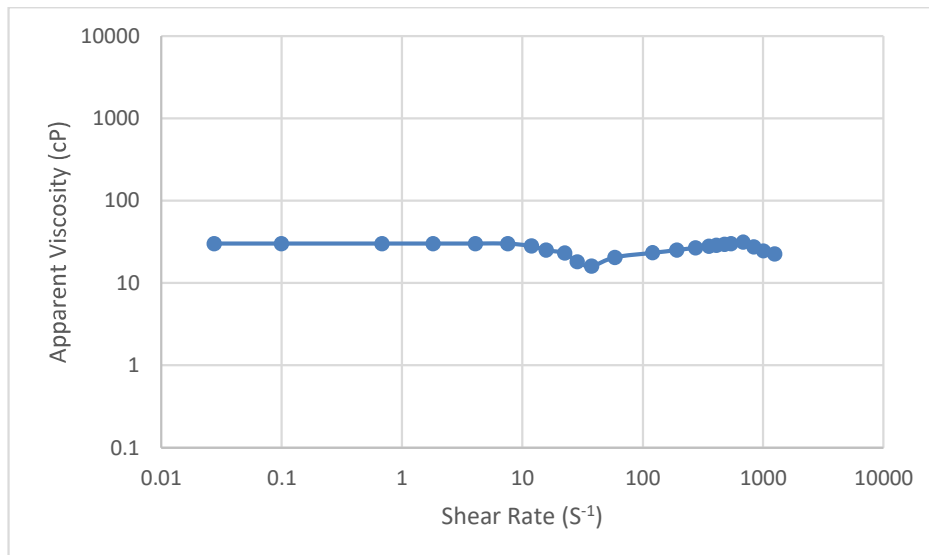


Figure A.18: Daqing field 30 cP polymer low shear thickening data set ($N_2 = 1.173$)

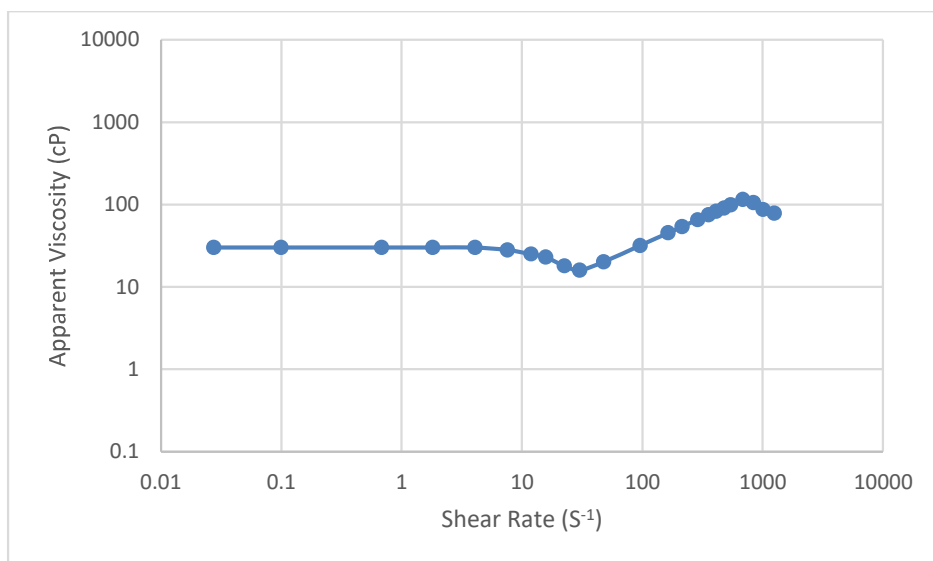


Figure A.19: Daqing field 30 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

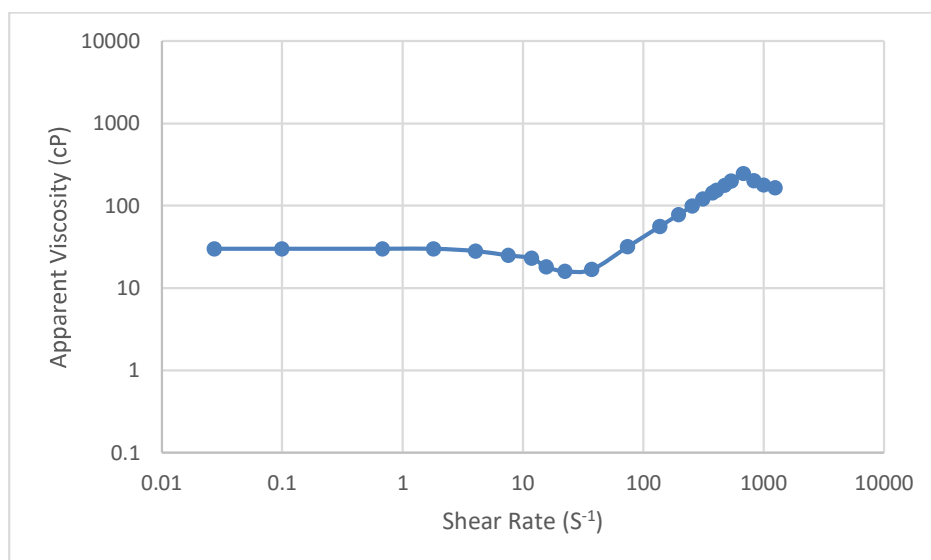


Figure A.20: Daqing field 30 cP polymer high shear thickening data set ($N_2 = 1.925$)

- Daqing field 300 cP polymer data:

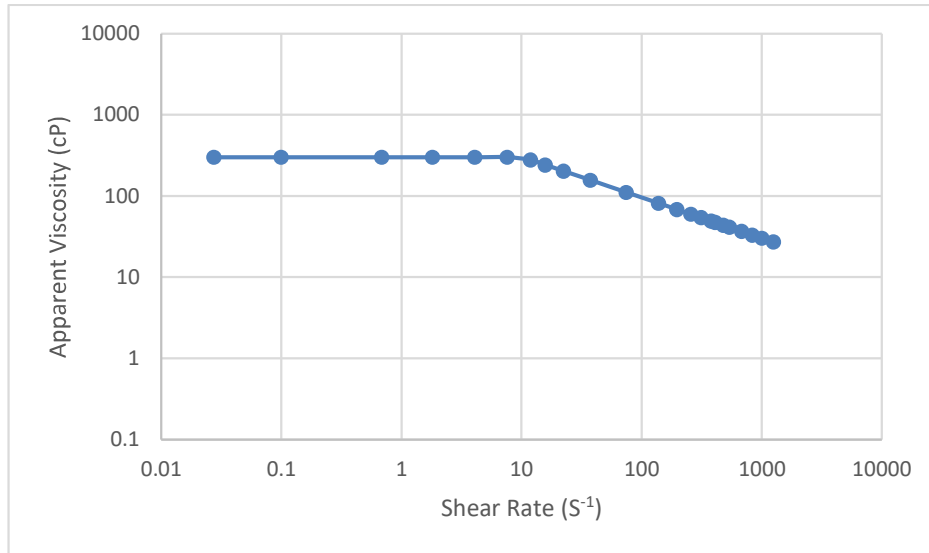


Figure A.21: Daqing field 300 cP polymer shear thinning data set ($N_1 = 0.5$)

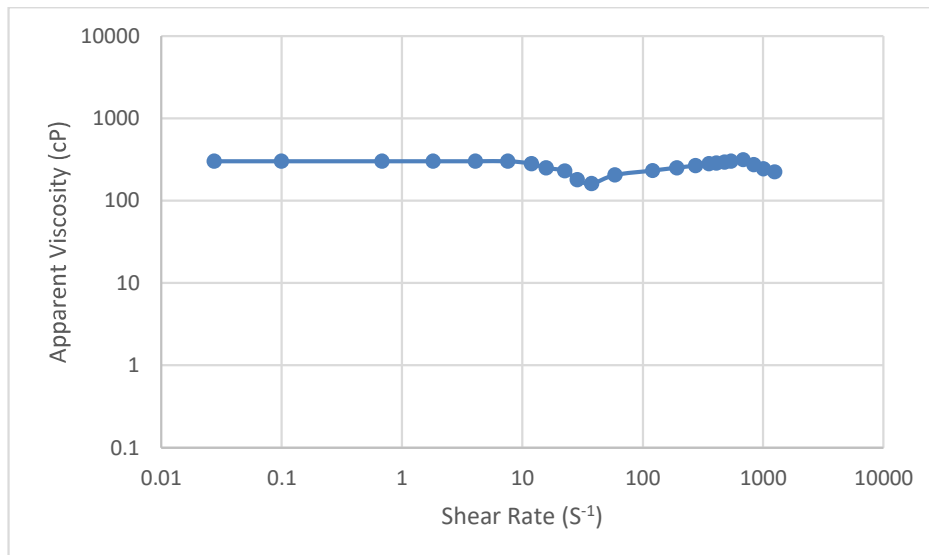


Figure A.22: Daqing field 300 cP polymer low shear thickening data set ($N_2 = 1.173$)

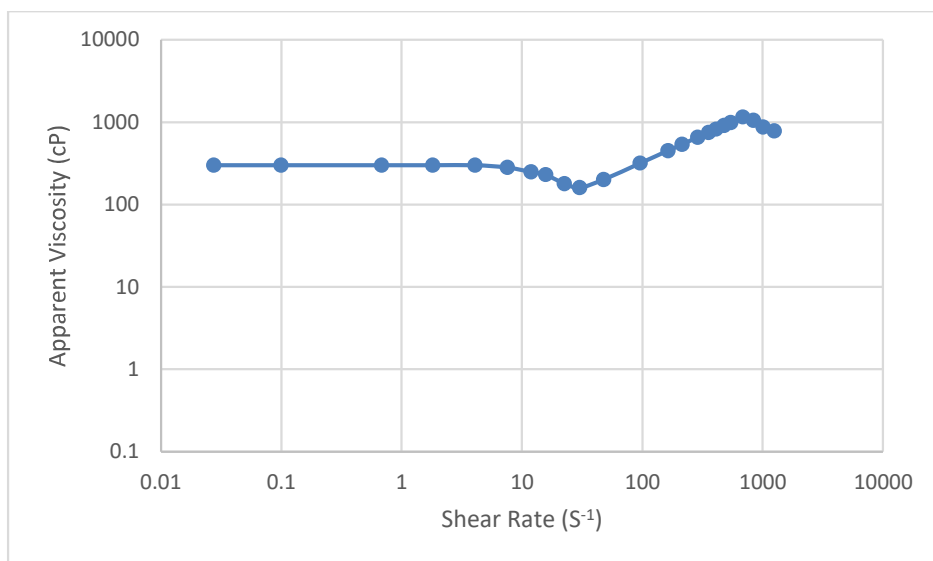


Figure A.23: Daqing field 300 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

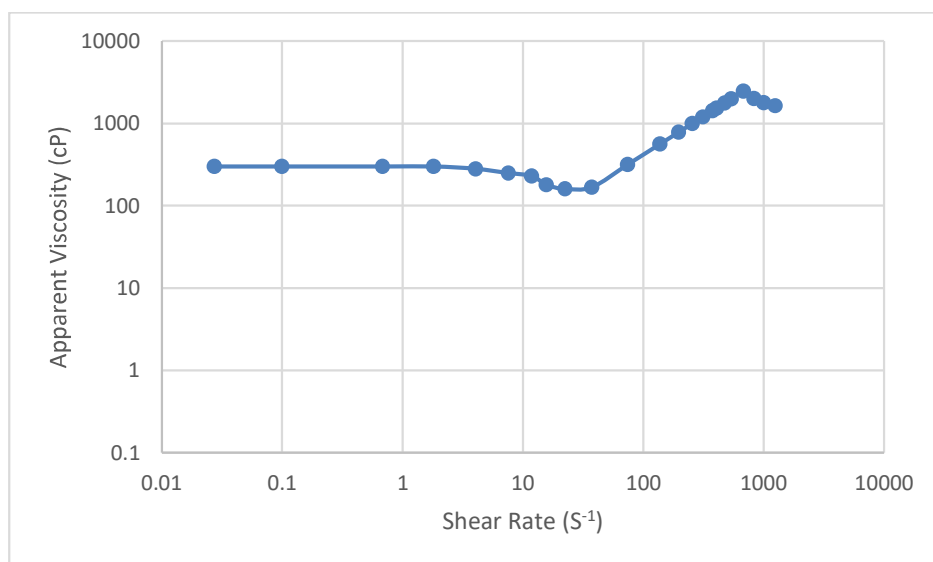


Figure A.24: Daqing field 300 cP polymer high shear thickening data set ($N_2 = 1.925$)

➤ **Pelican Lake Field:**

- Pelican Lake field 3 cP polymer data:

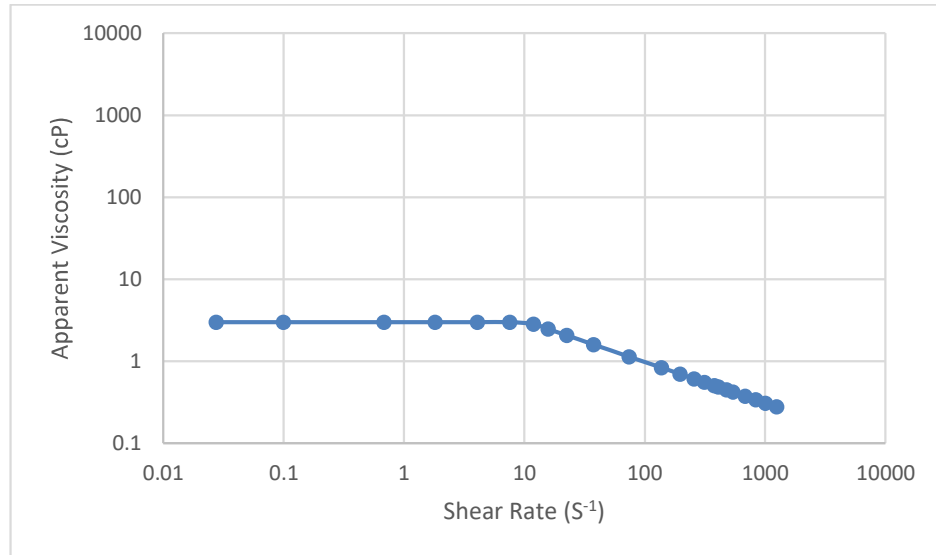


Figure A.25: Pelican Lake field 3 cP polymer shear thinning data set ($N_1 = 0.5$)

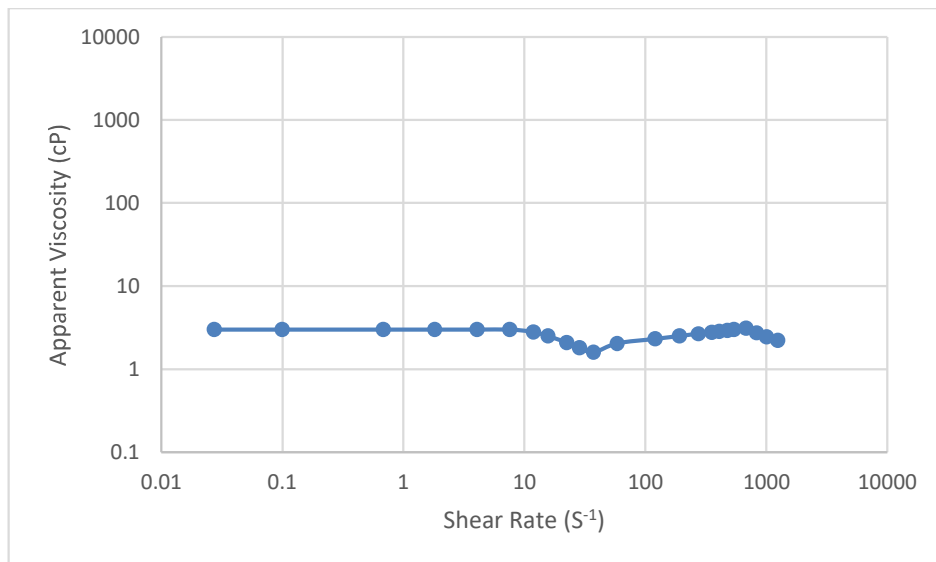


Figure A.26: Pelican Lake field 3 cP polymer low shear thickening data set ($N_2 = 1.173$)

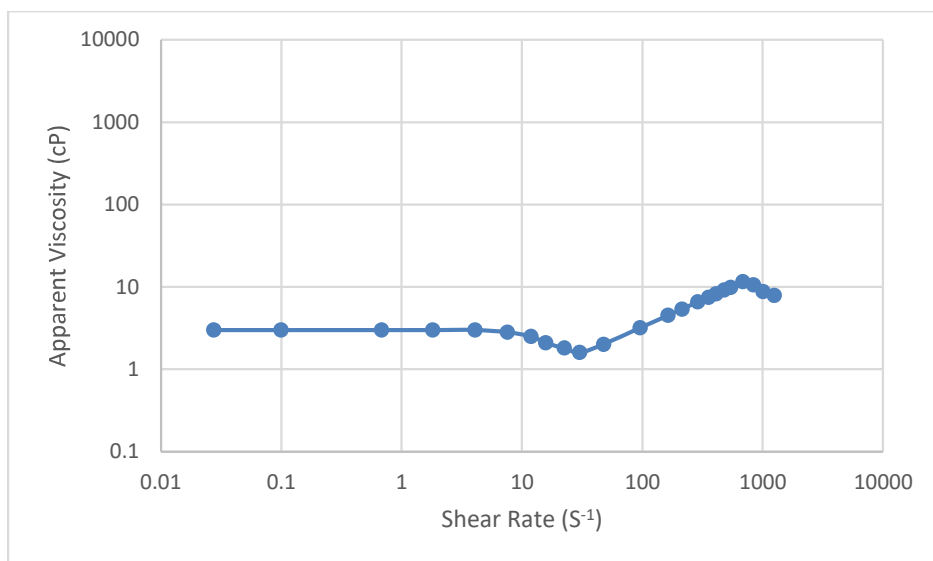


Figure A.27: Pelican Lake field 3 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

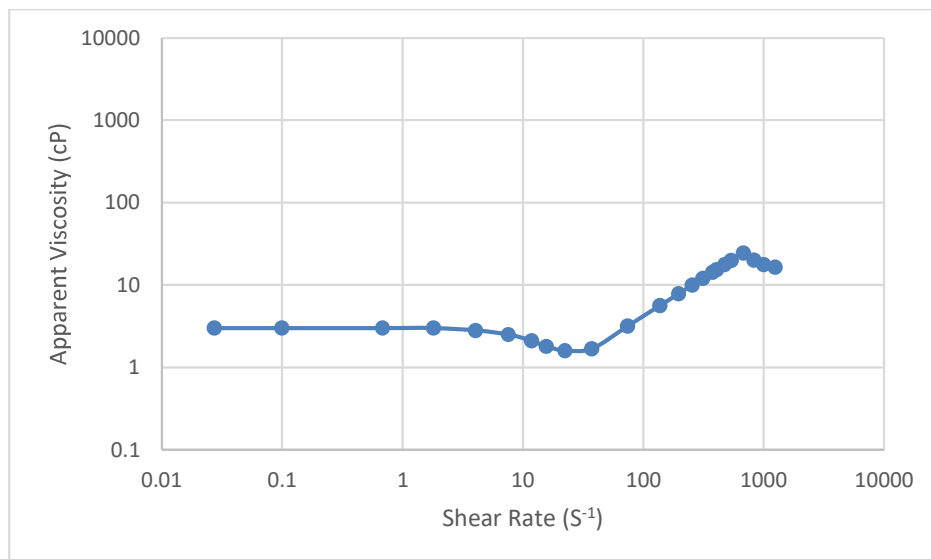


Figure A.28: Pelican Lake field 3 cP polymer high shear thickening data set ($N_2 = 1.925$)

- Pelican Lake field **30 cP** polymer data:

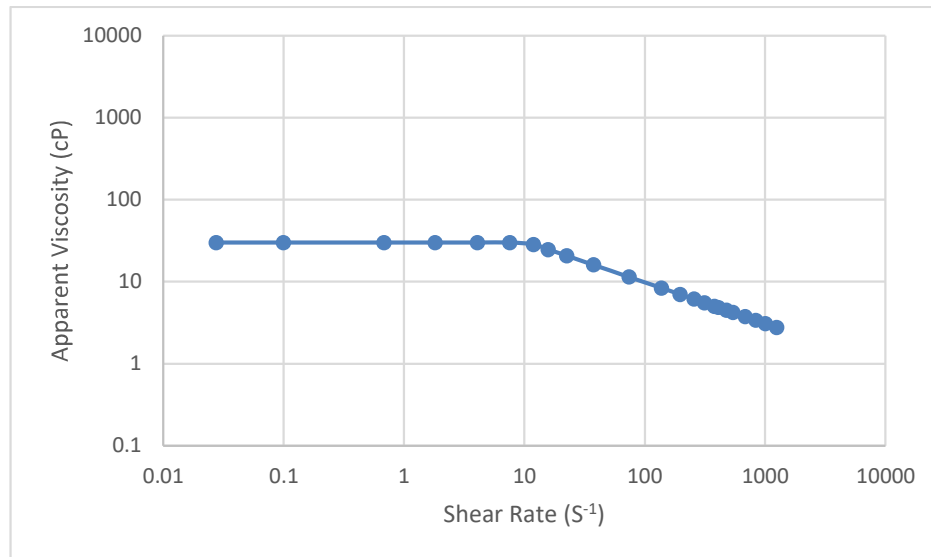


Figure A.29: Pelican Lake field 30 cP polymer shear thinning data set ($N_1 = 0.5$)

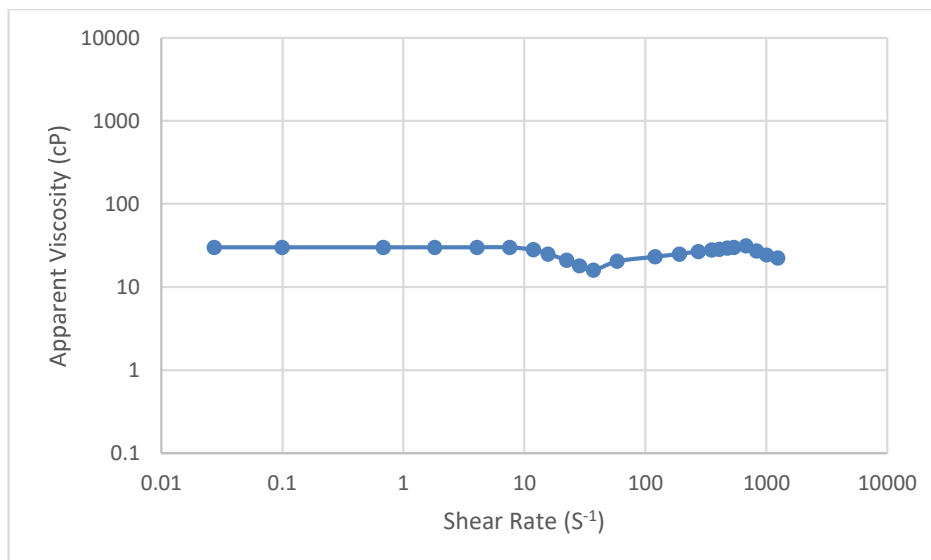


Figure A.30: Pelican Lake field 30 cP polymer low shear thickening data set ($N_2 = 1.173$)

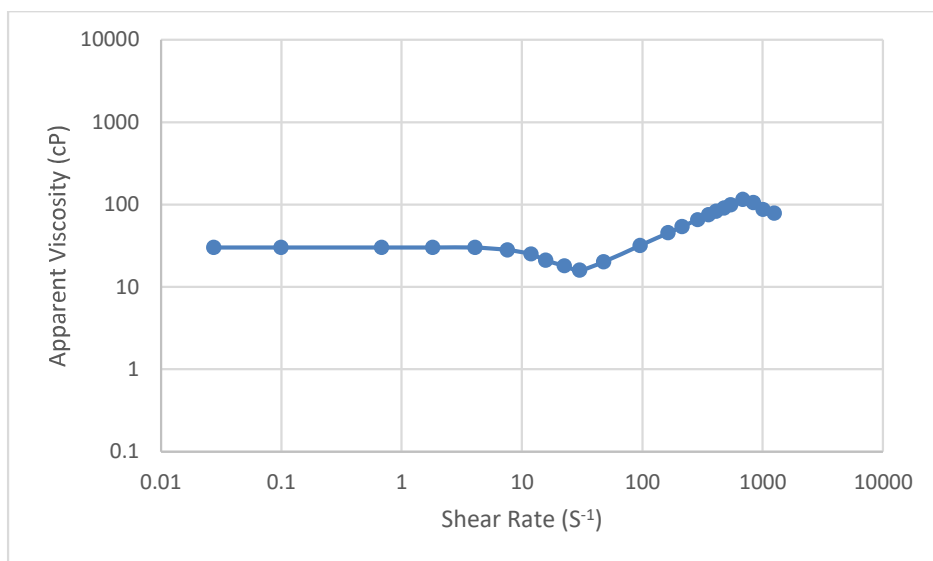


Figure A.31: Pelican Lake field 30 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

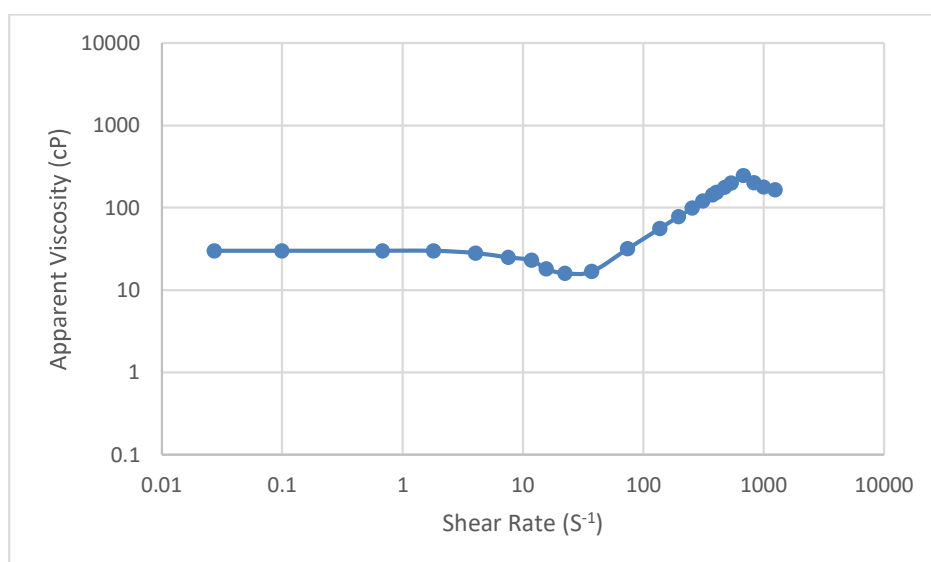


Figure A.32: Pelican Lake field 30 cP polymer high shear thickening data set ($N_2 = 1.925$)

- Pelican Lake field **300 cP** polymer data:

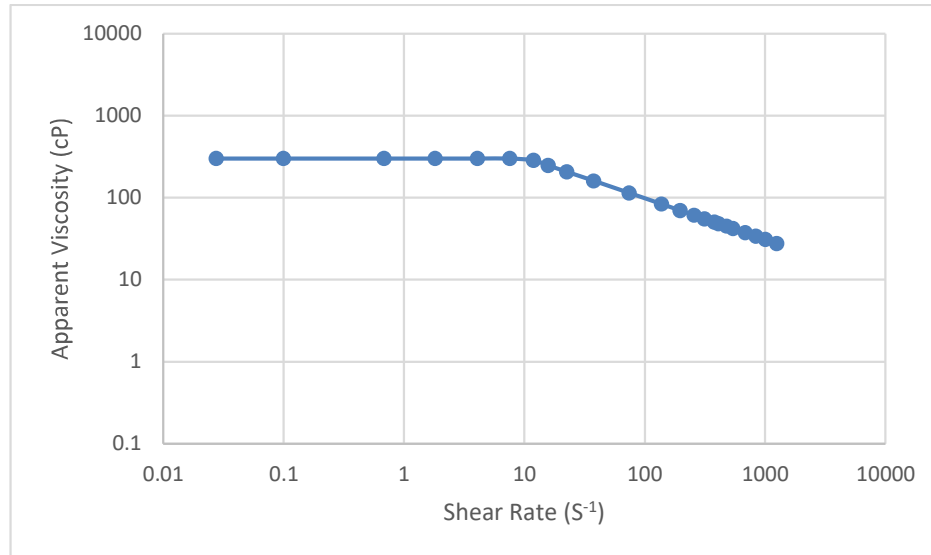


Figure A.33: Pelican Lake field 300 cP polymer shear thinning data set ($N_1 = 0.5$)

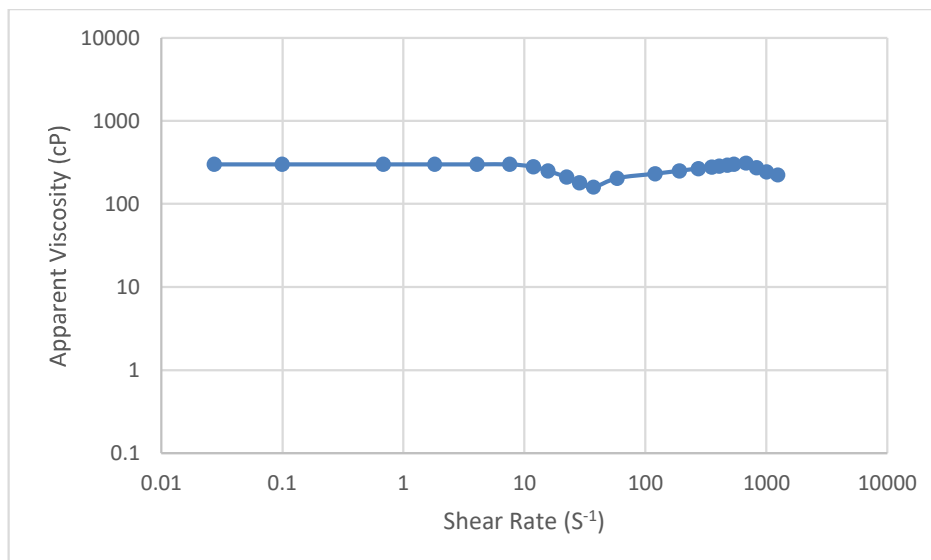


Figure A.34: Pelican Lake field 300 cP polymer low shear thickening data set ($N_2 = 1.173$)

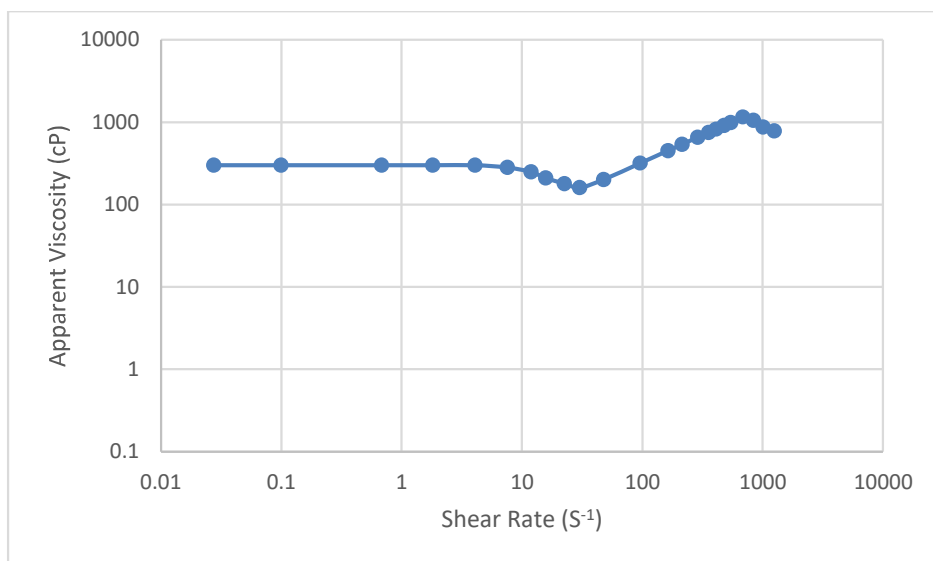


Figure A.35: Pelican Lake field 300 cP polymer medium shear thickening data set ($N_2 = 1.6554$)

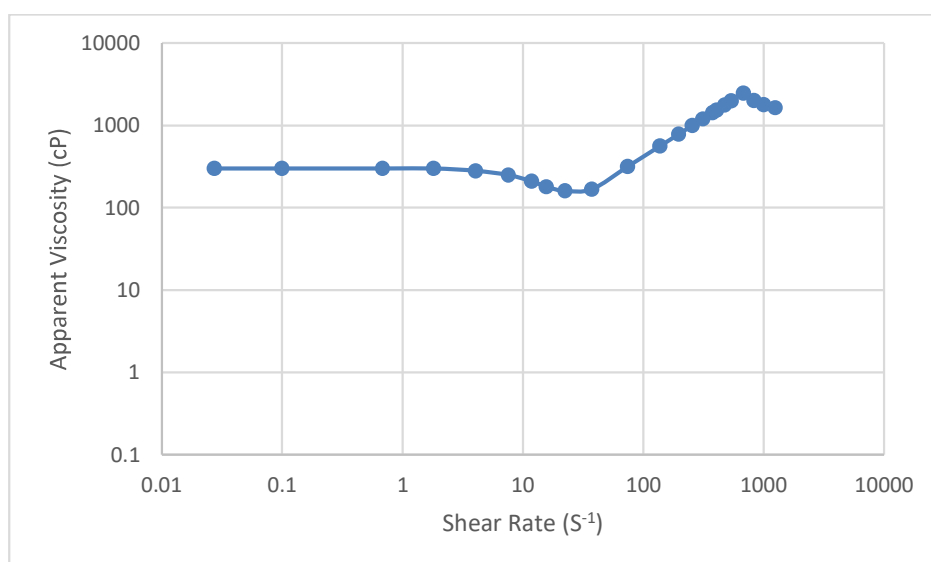


Figure A.36: Pelican Lake field 300 cP polymer high shear thickening data set ($N_2 = 1.925$)

Appendix B

In this appendix, the injectivity and injection pressure optimization in addition to resulting oil production rate and total produced oil volume for all field cases will be presented.

➤ Matzen Field:

- Matzen field **2.5 cP** vertical producer (VP) case:

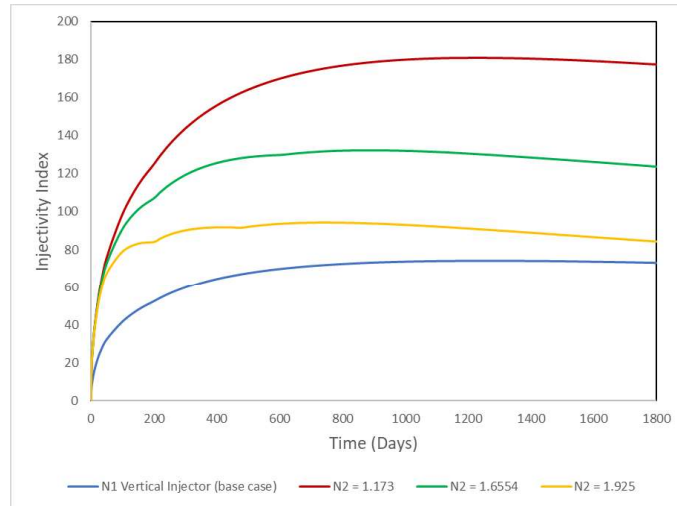


Figure B. 1: Matzen field optimized injectivity for 2.5 cP polymer viscosity (VP)

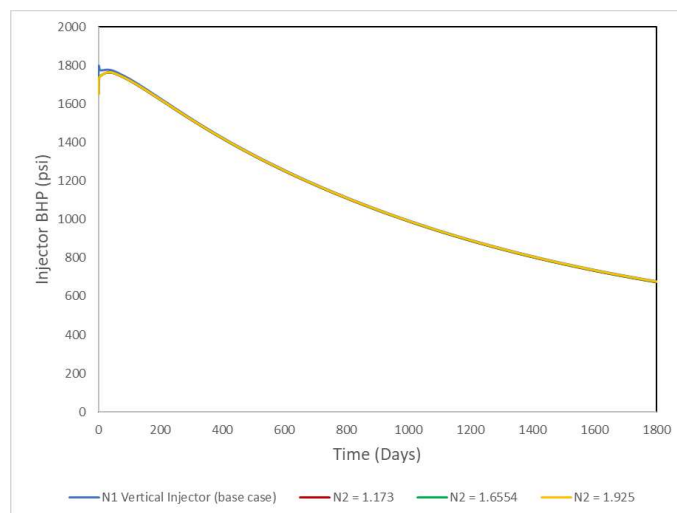


Figure B. 2: Matzen field optimized injection BHP for 2.5 cP polymer viscosity (VP)

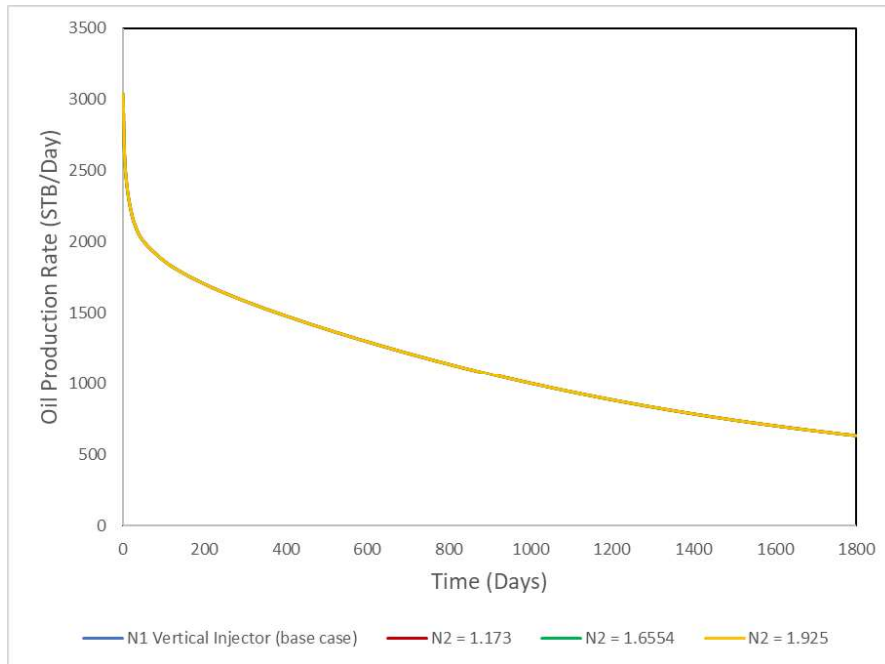


Figure B. 3: Matzen field oil production rate for 2.5 cP polymer viscosity (VP)

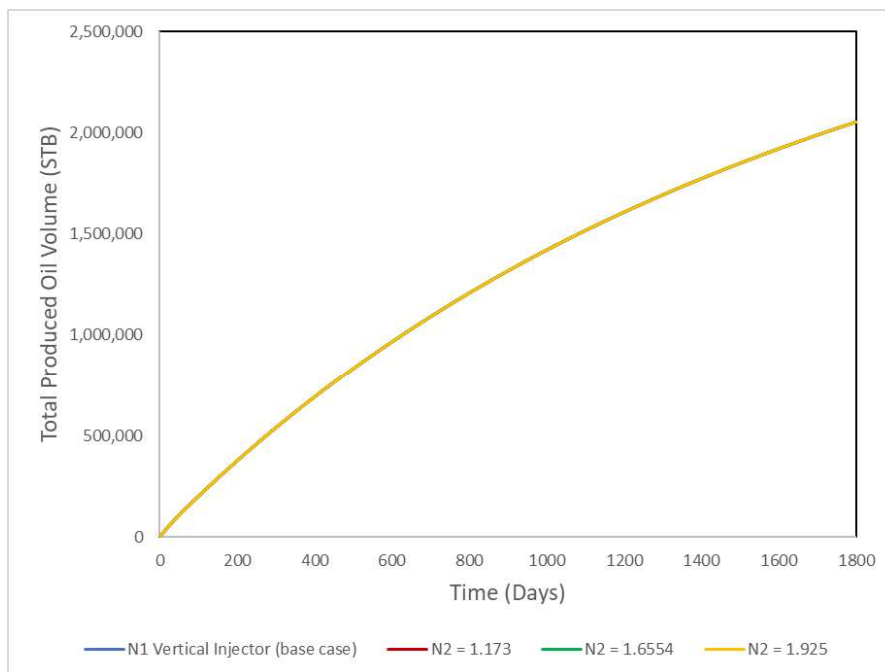


Figure B. 4: Matzen field total produced oil volume for 2.5 cP polymer viscosity (VP)

- Matzen field **10 cP** vertical producer (VP) case:

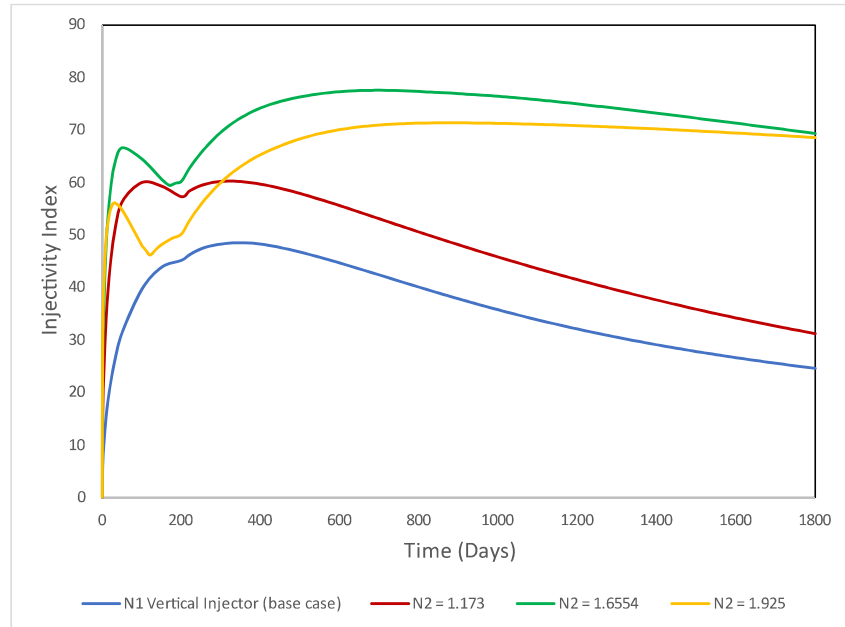


Figure B. 5: Matzen field optimized injectivity for 10 cP polymer viscosity (VP)

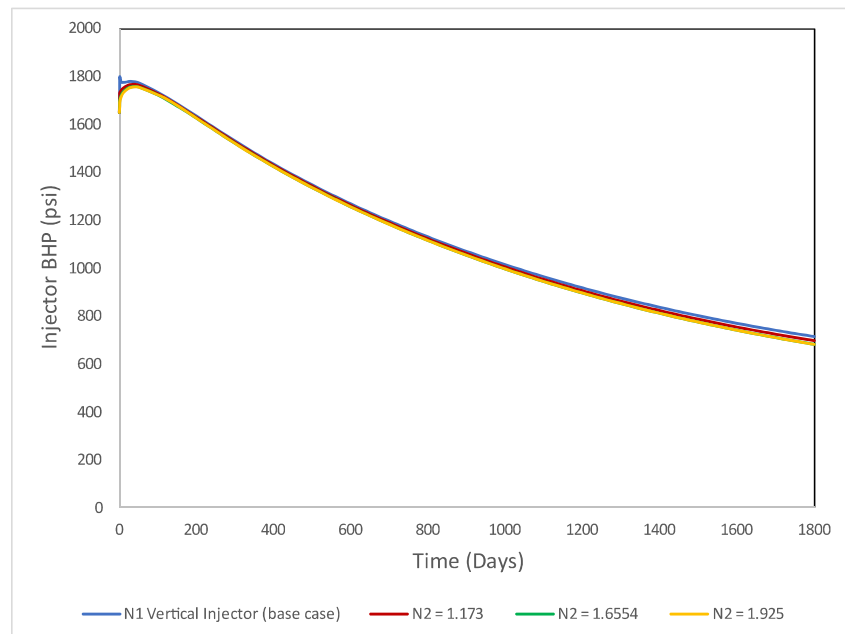


Figure B. 6: Matzen field optimized injection BHP for 10 cP polymer viscosity (VP)

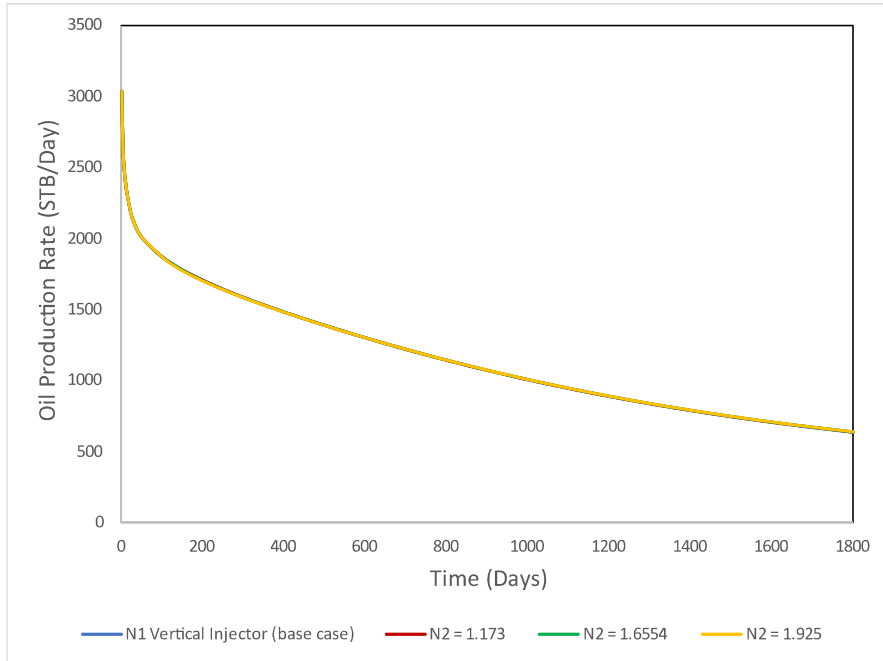


Figure B. 7: Matzen field oil production rate for 10 cP polymer viscosity (VP)

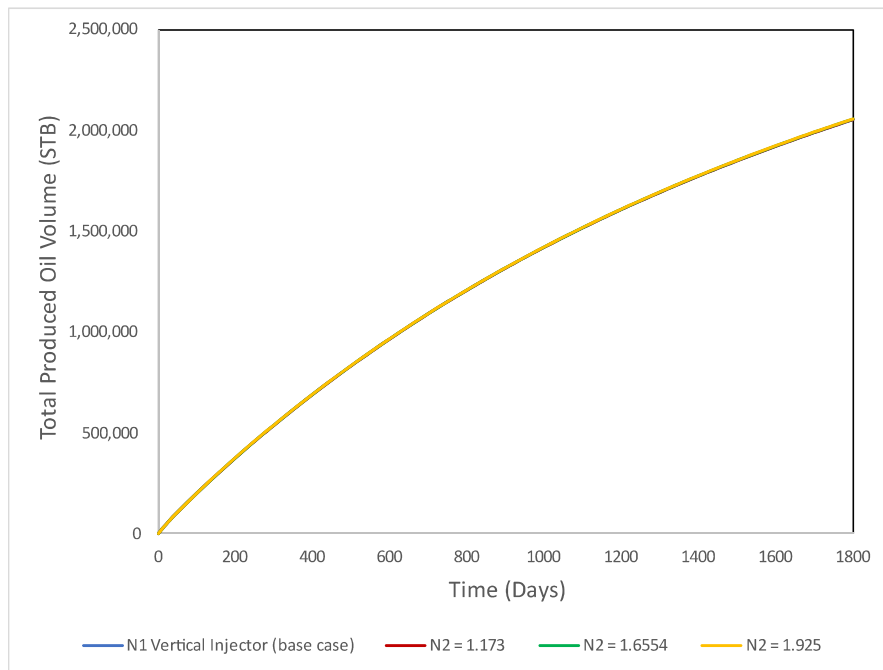


Figure B. 8: Matzen field total produced oil volume for 10 cP polymer viscosity (VP)

- Matzen field **100 cP** vertical producer (VP) case:

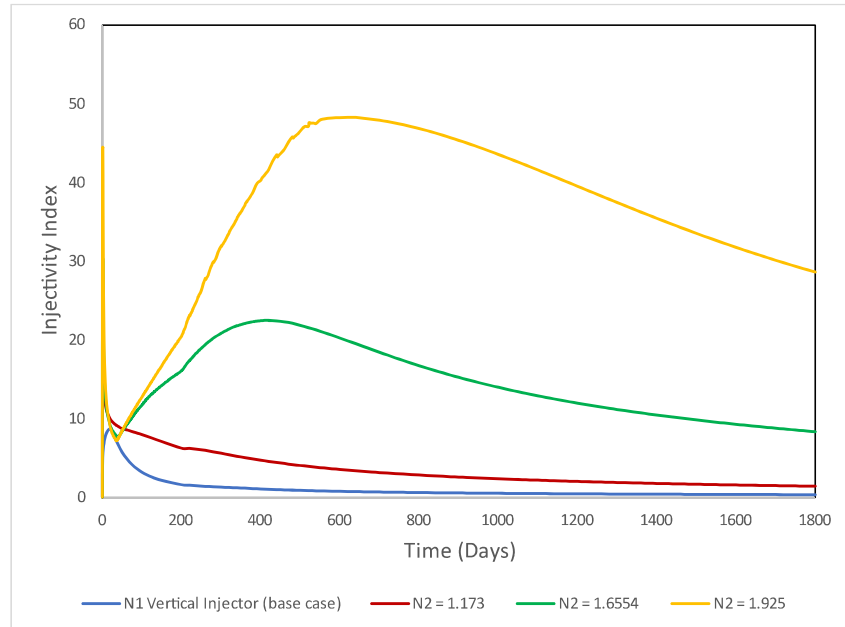


Figure B. 9: Matzen field optimized injectivity for 100 cP polymer viscosity (VP)

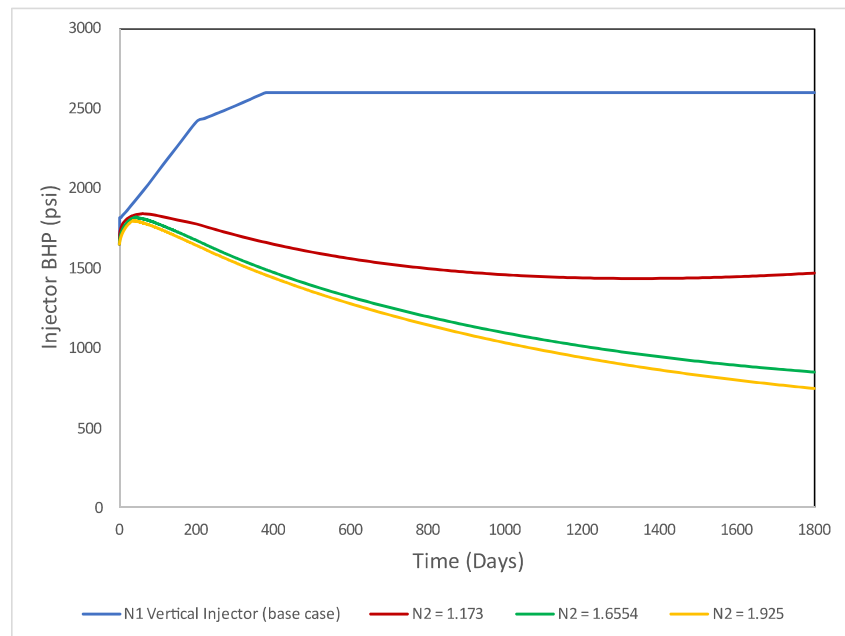


Figure B. 10: Matzen field optimized injection BHP for 100 cP polymer viscosity (VP)

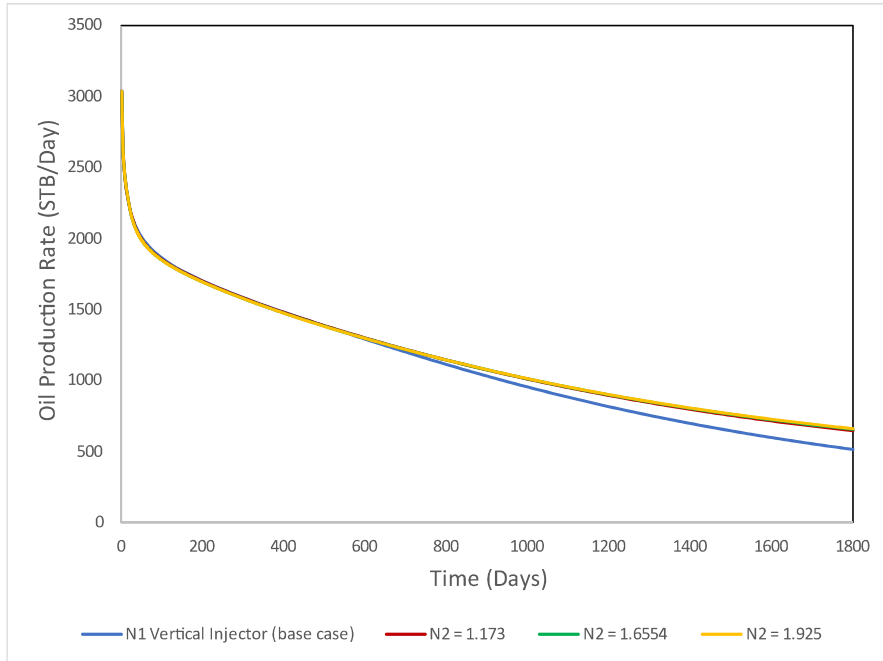


Figure B. 11: Matzen field oil production rate for 100 cP polymer viscosity (VP)

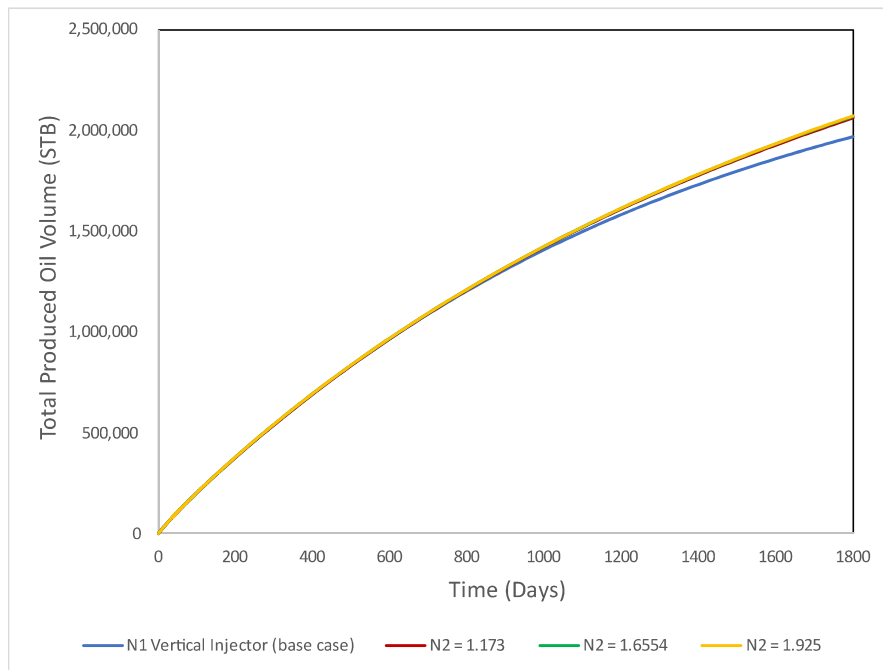


Figure B. 12: Matzen field total produced oil volume for 100 cP polymer viscosity (VP)

- Matzen field **2.5 cP** horizontal producer (HP) case:

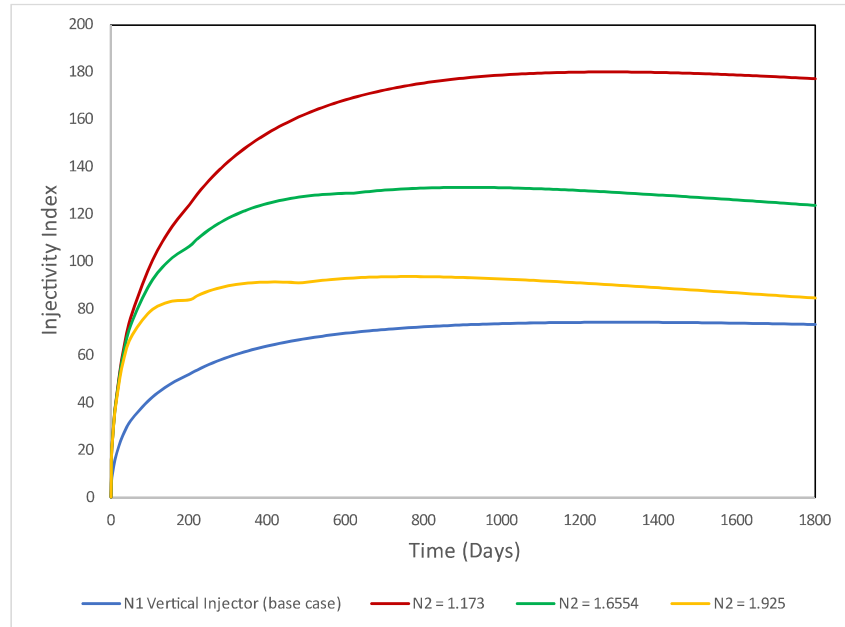


Figure B. 13: Matzen field optimized injectivity for 2.5 cP polymer viscosity (HP)

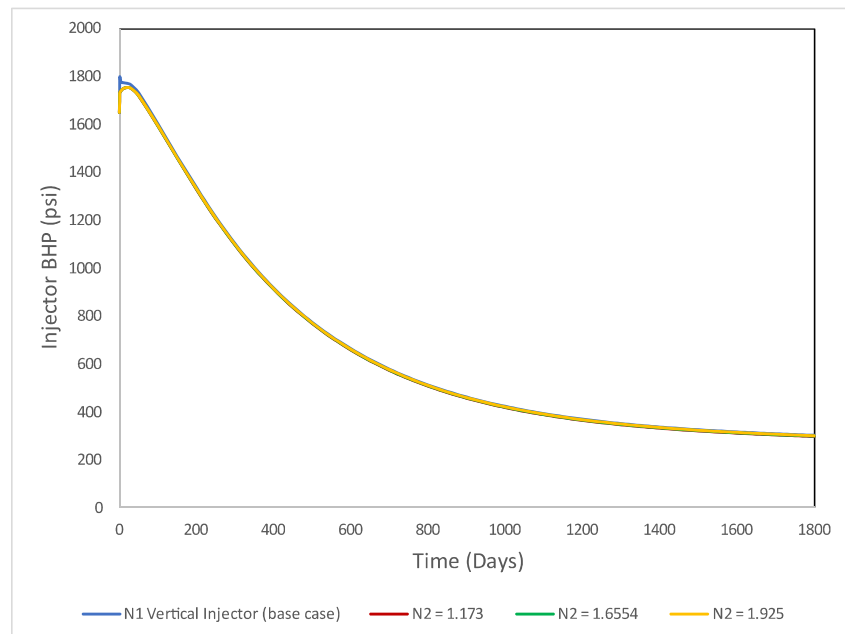


Figure B. 14: Matzen field optimized injection BHP for 2.5 cP polymer viscosity (HP)

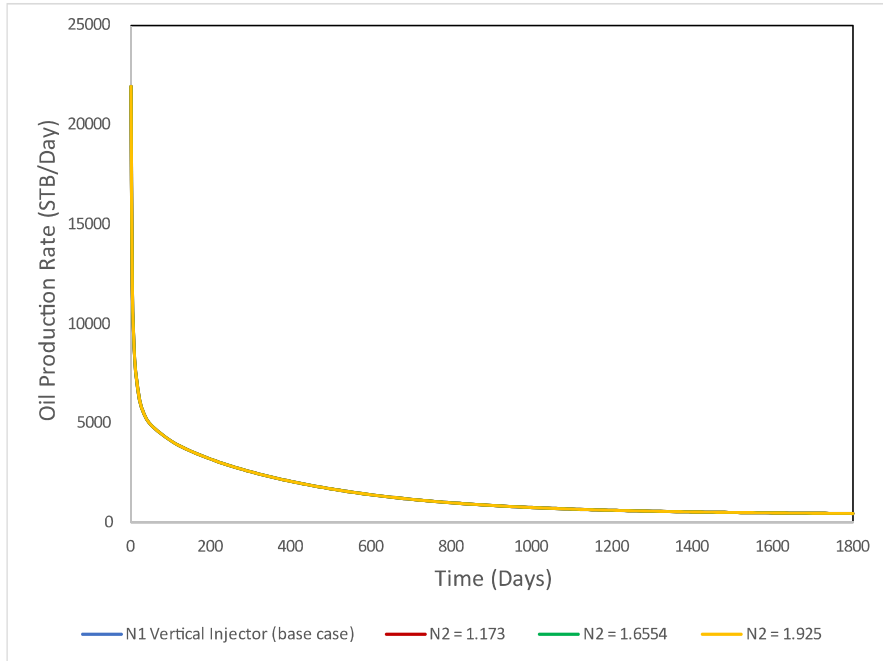


Figure B. 15: Matzen field oil production rate for 2.5 cP polymer viscosity (HP)

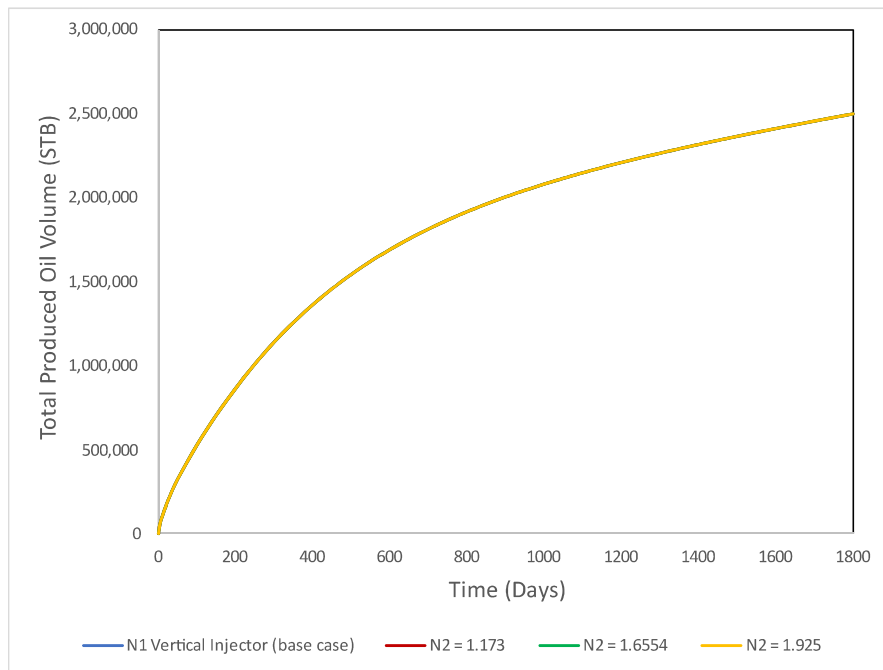


Figure B. 16: Matzen field total produced oil volume for 2.5 cP polymer viscosity (HP)

- Matzen field **10 cP** horizontal producer (HP) case:

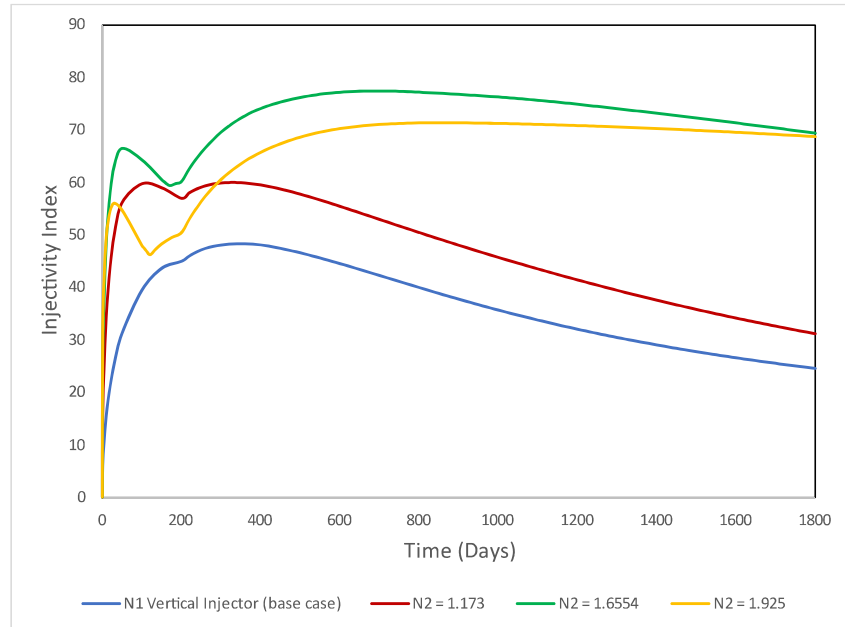


Figure B. 17: Matzen field optimized injectivity for 10 cP polymer viscosity (HP)

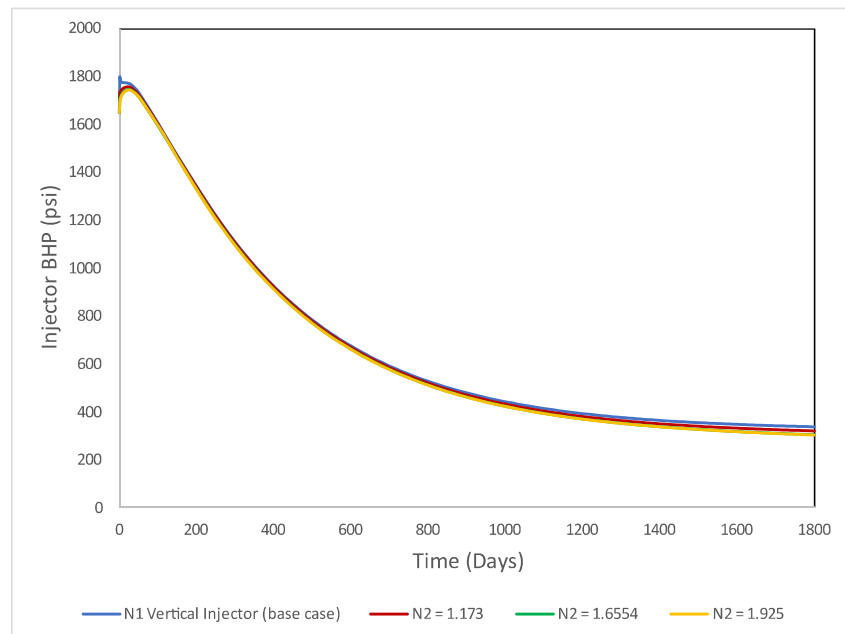


Figure B. 18: Matzen field optimized injection BHP for 10 cP polymer viscosity (HP)

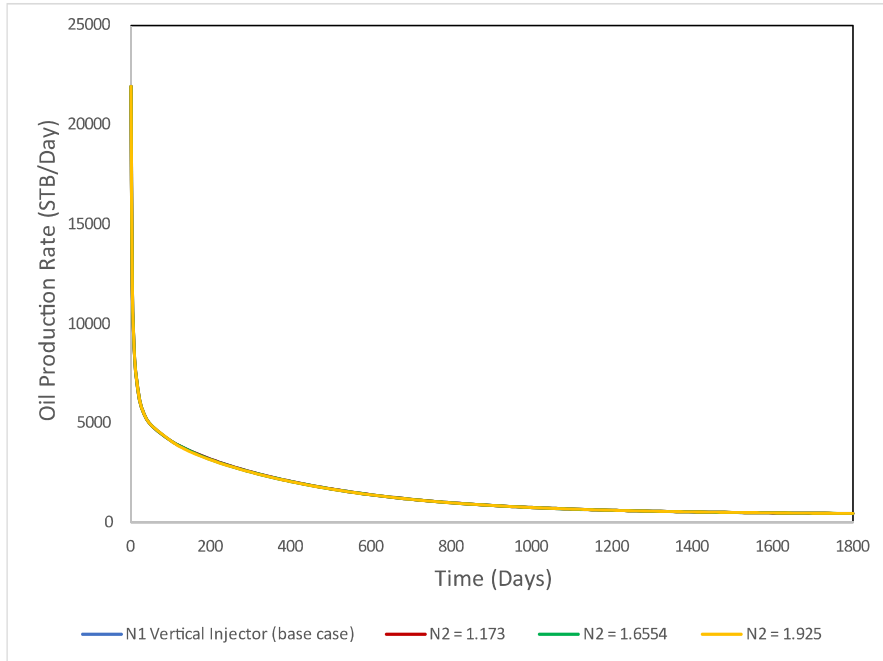


Figure B. 19: Matzen field oil production rate for 10 cP polymer viscosity (HP)

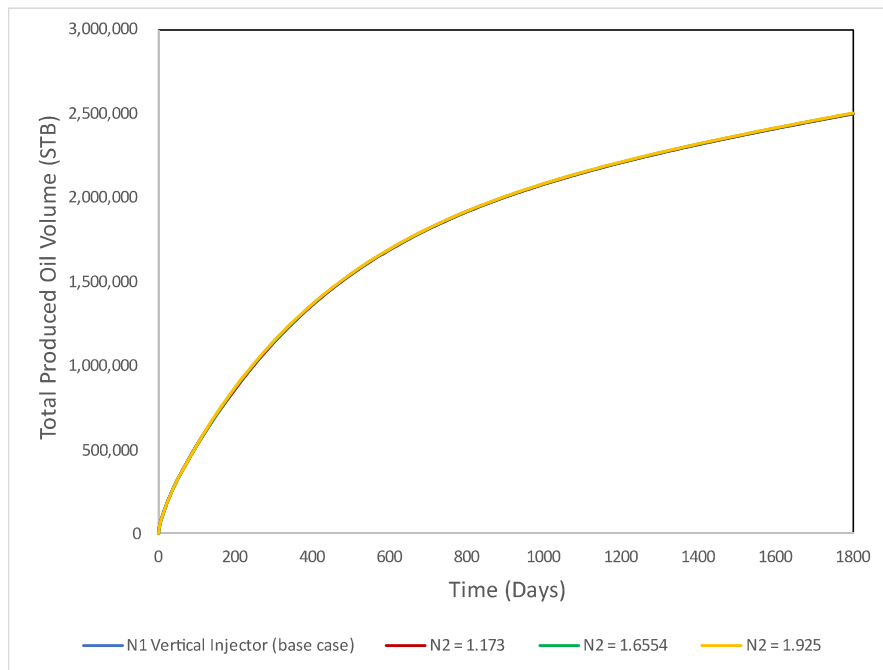


Figure B. 20: Matzen field total produced oil volume for 10 cP polymer viscosity (HP)

- Matzen field **100 cP** horizontal producer (HP) case:

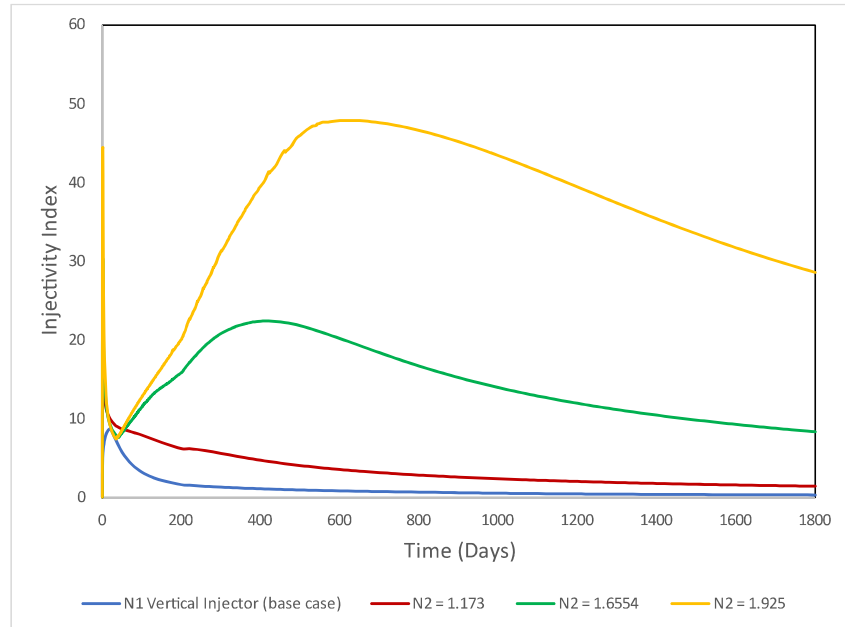


Figure B. 21: Matzen field optimized injectivity for 100 cP polymer viscosity (HP)

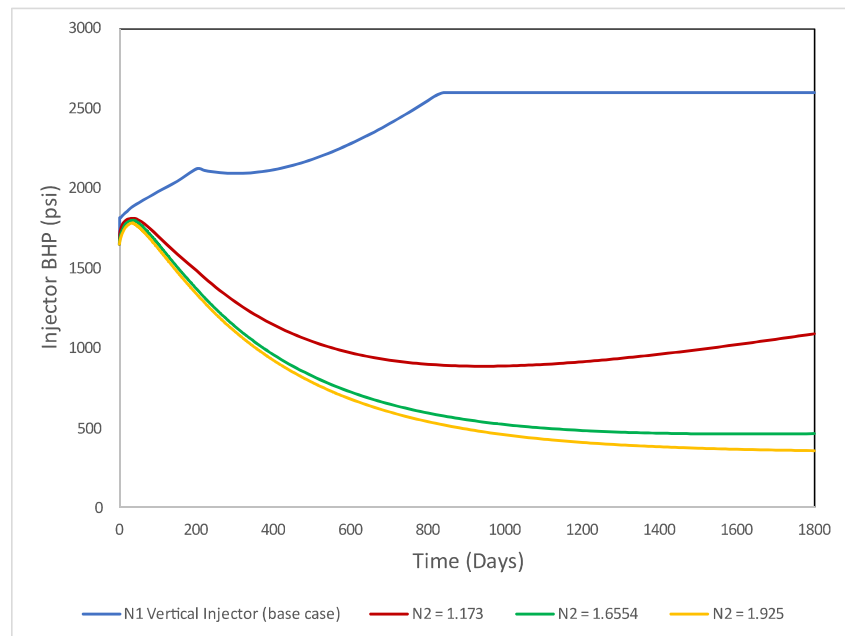


Figure B. 22: Matzen field optimized injection BHP for 100 cP polymer viscosity (HP)

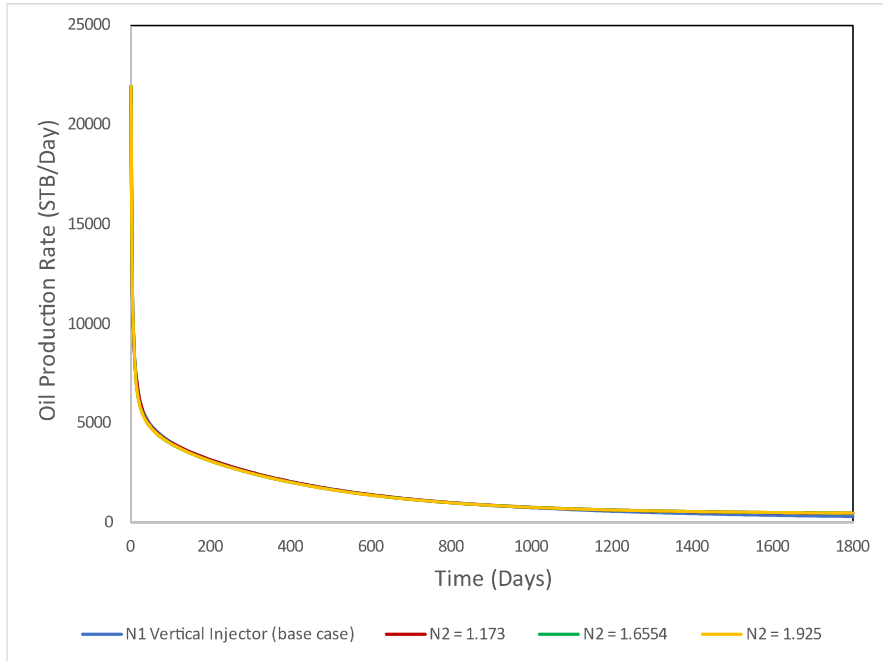


Figure B. 23: Matzen field oil production rate for 100 cP polymer viscosity (HP)

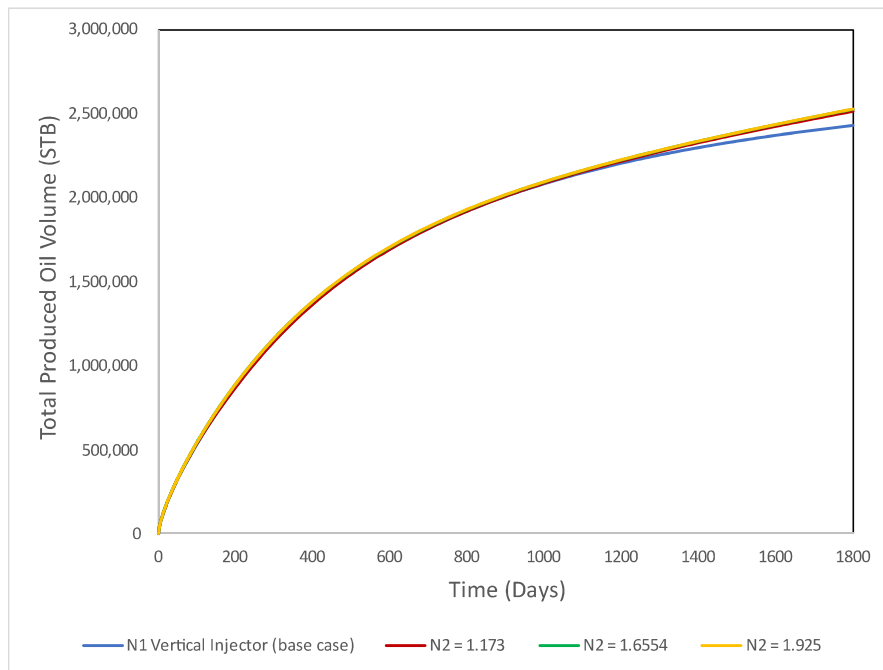


Figure B. 24: Matzen field total produced oil volume for 100 cP polymer viscosity (HP)

➤ **Daqing Field:**

- Daqing field 3 cP vertical producer (VP) case:

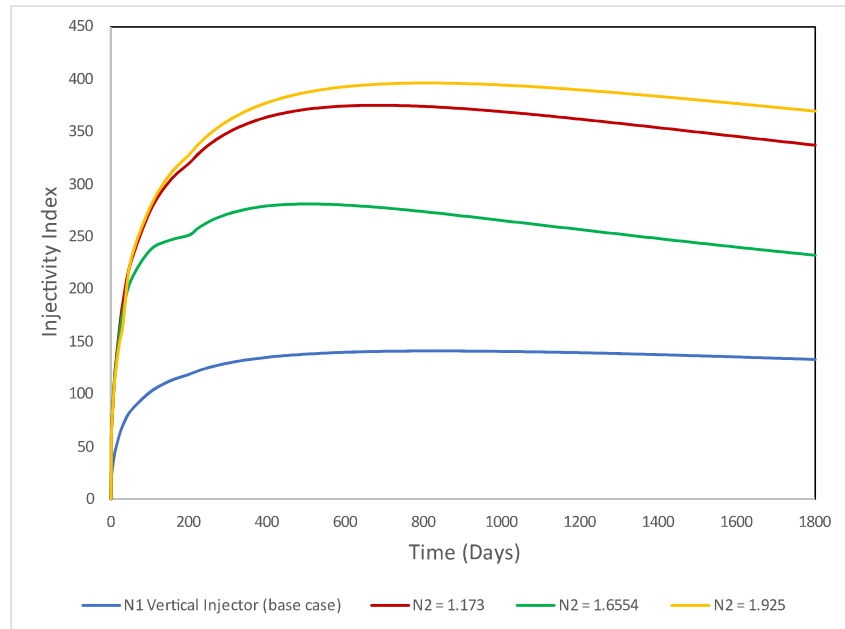


Figure B. 25: Daqing field optimized injectivity for 3 cP polymer viscosity (VP)

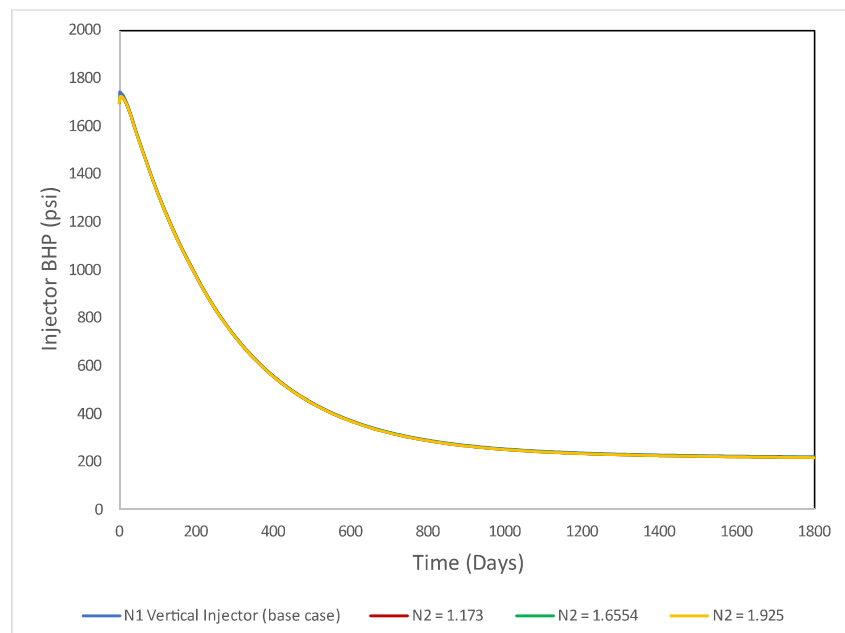


Figure B. 26: Daqing field optimized injection BHP for 3 cP polymer viscosity (VP)

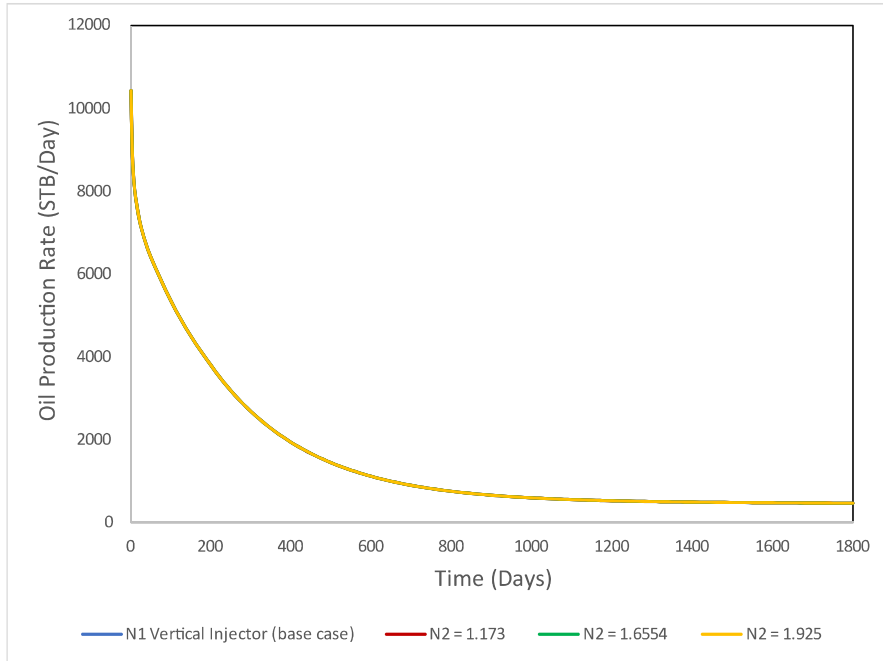


Figure B. 27: Daqing field oil production rate for 3 cP polymer viscosity (VP)

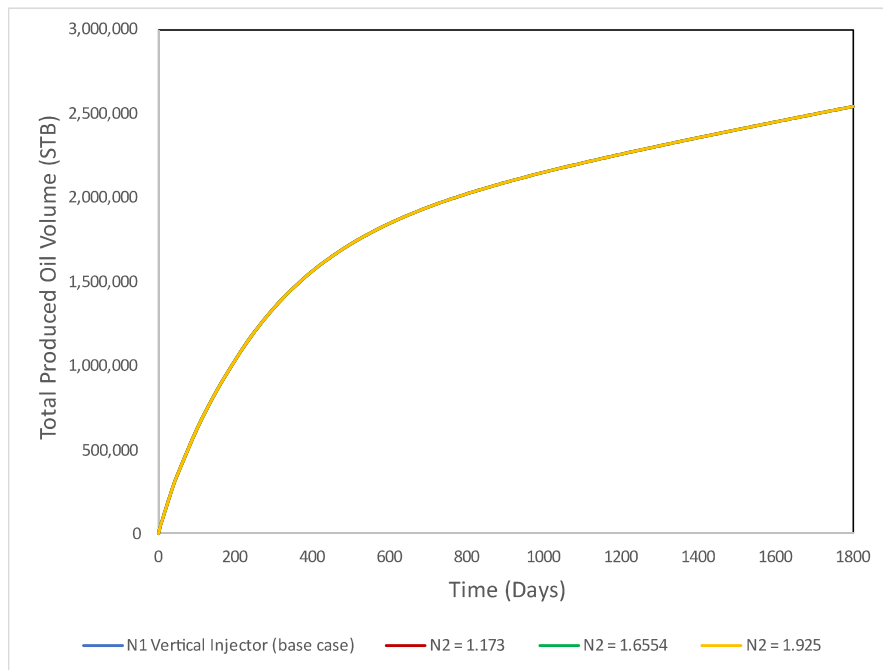


Figure B. 28: Daqing field total produced oil volume for 3 cP polymer viscosity (VP)

- Daqing field 30 cP vertical producer (VP) case:

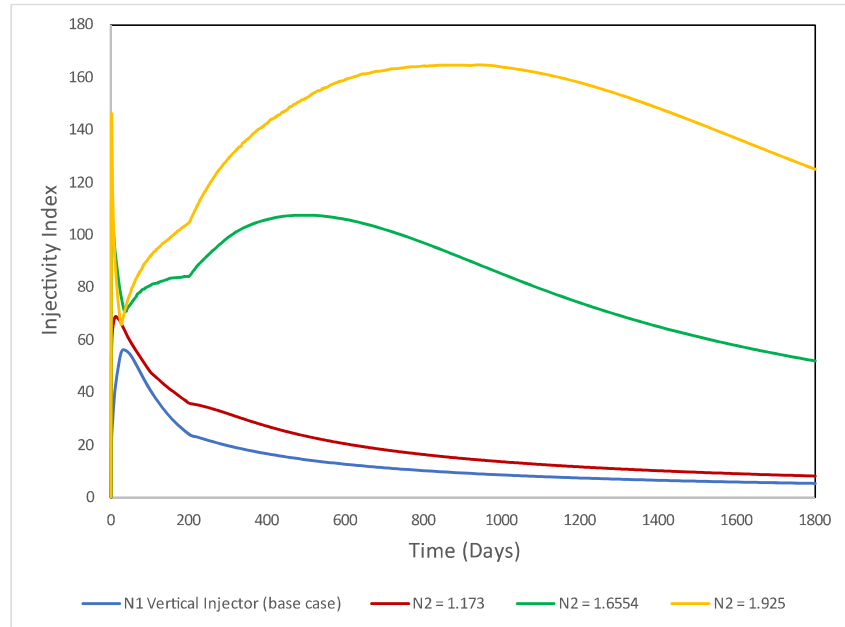


Figure B. 29: Daqing field optimized injectivity for 30 cP polymer viscosity (VP)

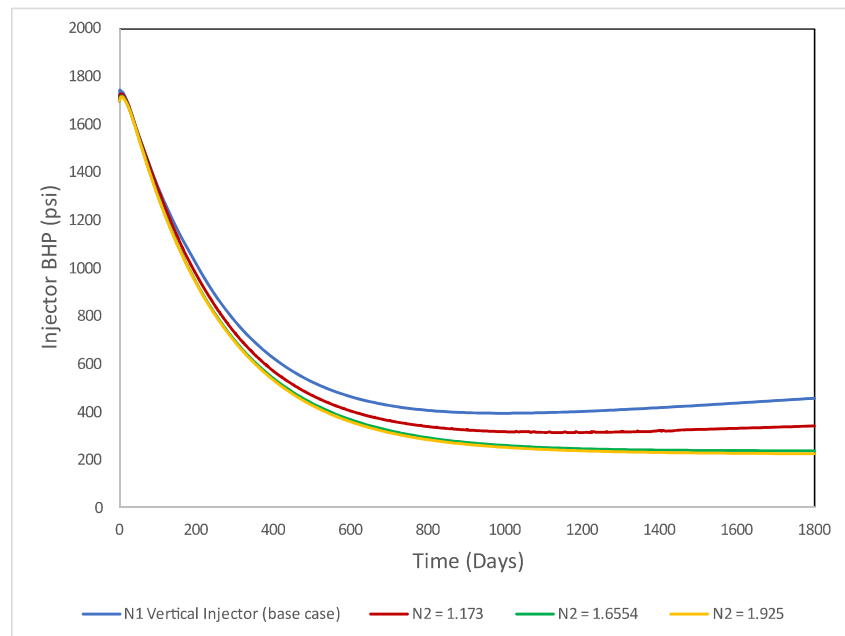


Figure B. 30: Daqing field optimized injection BHP for 30 cP polymer viscosity (VP)

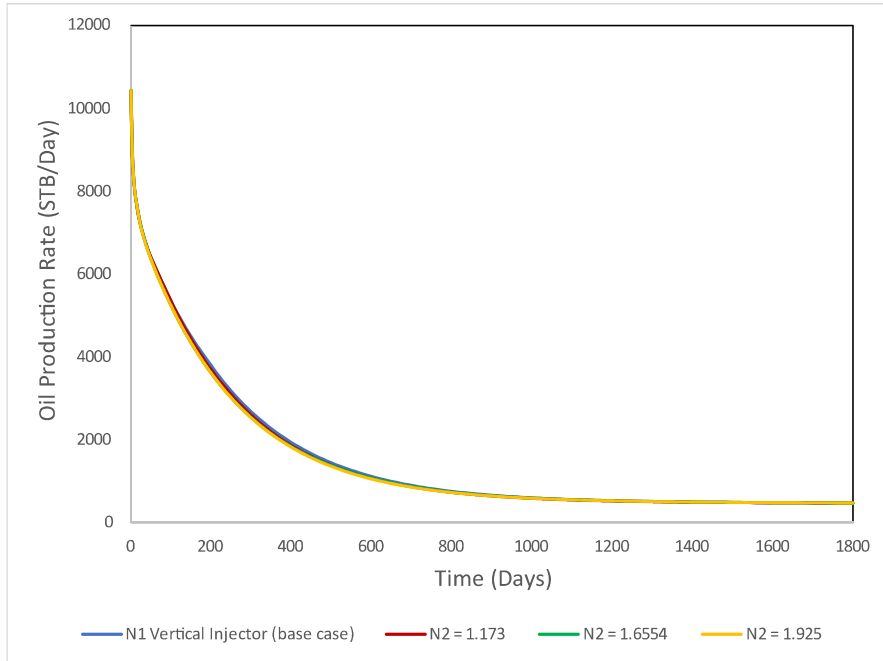


Figure B. 31: Daqing field oil production rate for 30 cP polymer viscosity (VP)

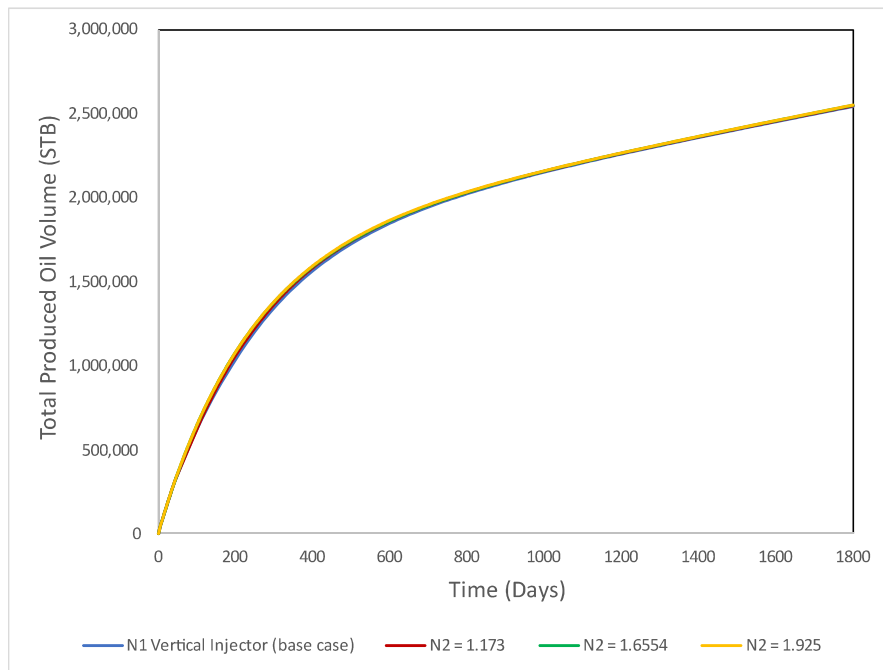


Figure B. 32: Daqing field total produced oil volume for 30 cP polymer viscosity (VP)

- Daqing field **300 cP** vertical producer (VP) case:

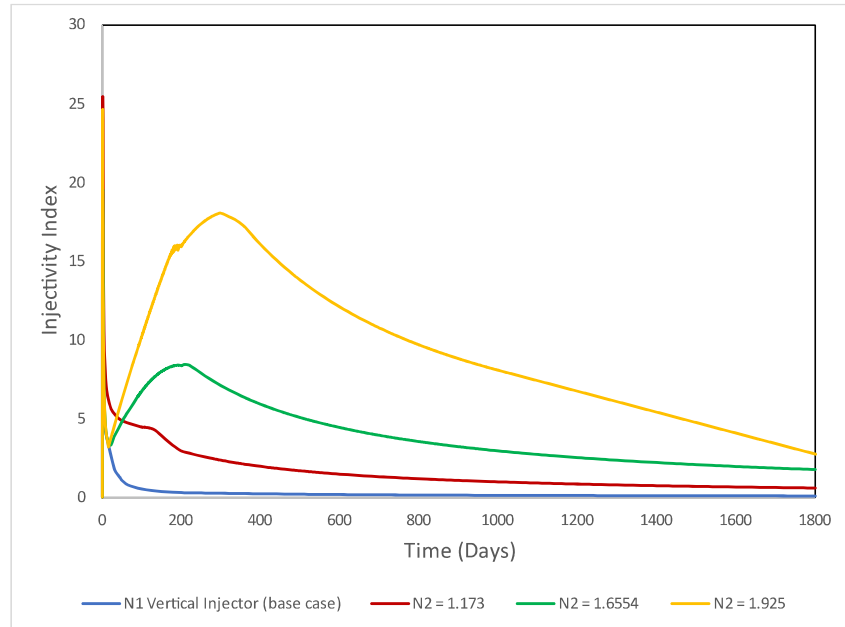


Figure B. 33: Daqing field optimized injectivity for 300 cP polymer viscosity (VP)

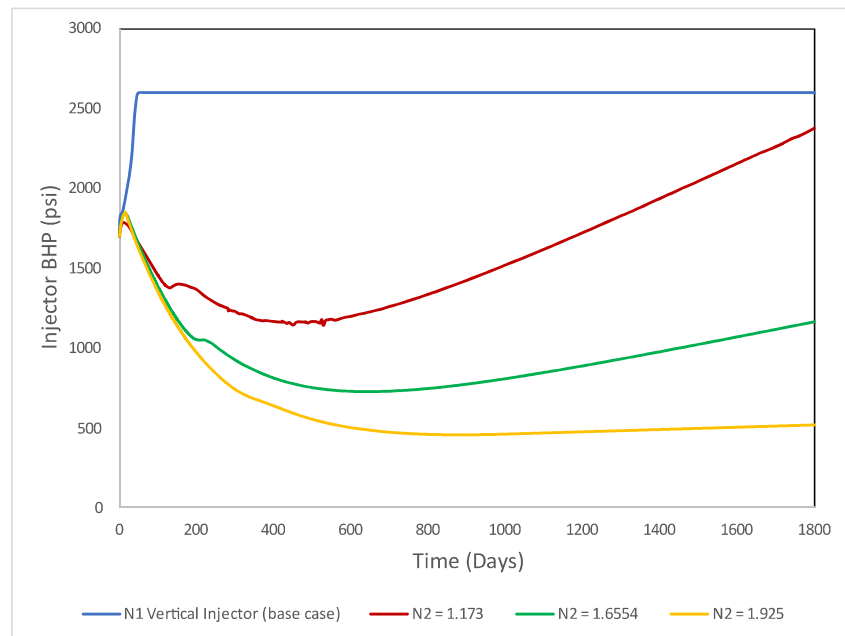


Figure B. 34: Daqing field optimized injection BHP for 300 cP polymer viscosity (VP)

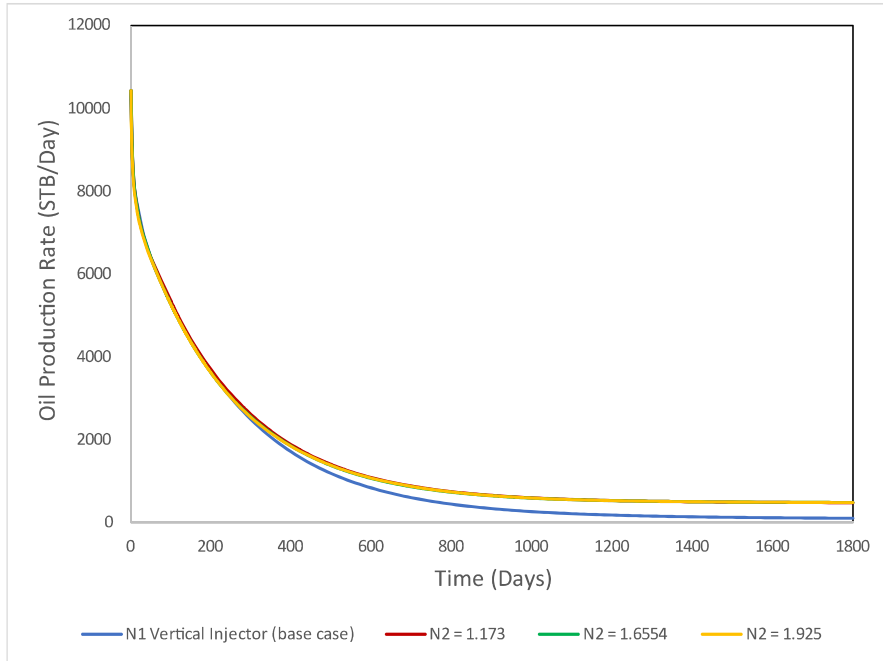


Figure B. 35: Daqing field oil production rate for 300 cP polymer viscosity (VP)

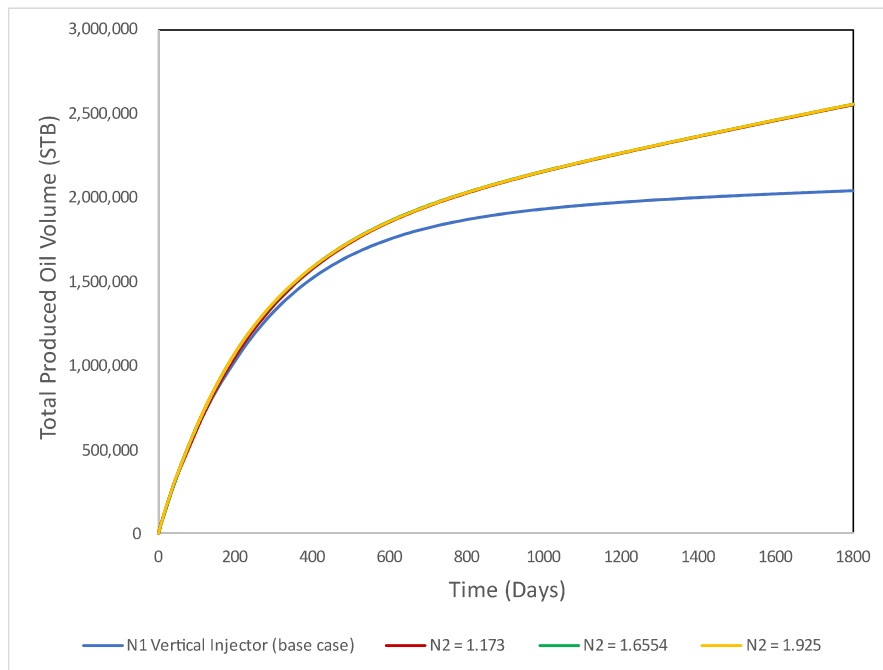


Figure B. 36: Daqing field total produced oil volume for 300 cP polymer viscosity (VP)

- Daqing field 3 cP horizontal producer (HP) case:

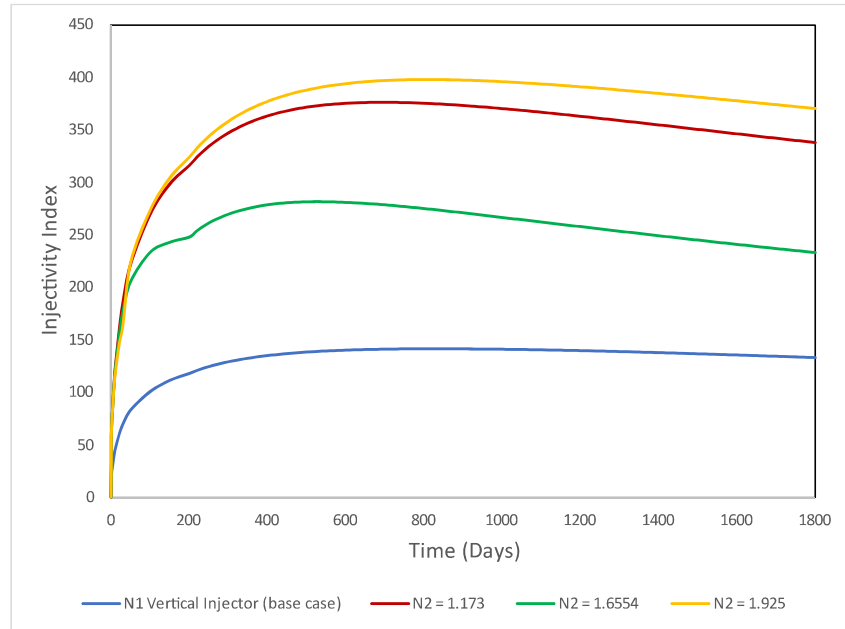


Figure B. 37: Daqing field optimized injectivity for 3 cP polymer viscosity (HP)

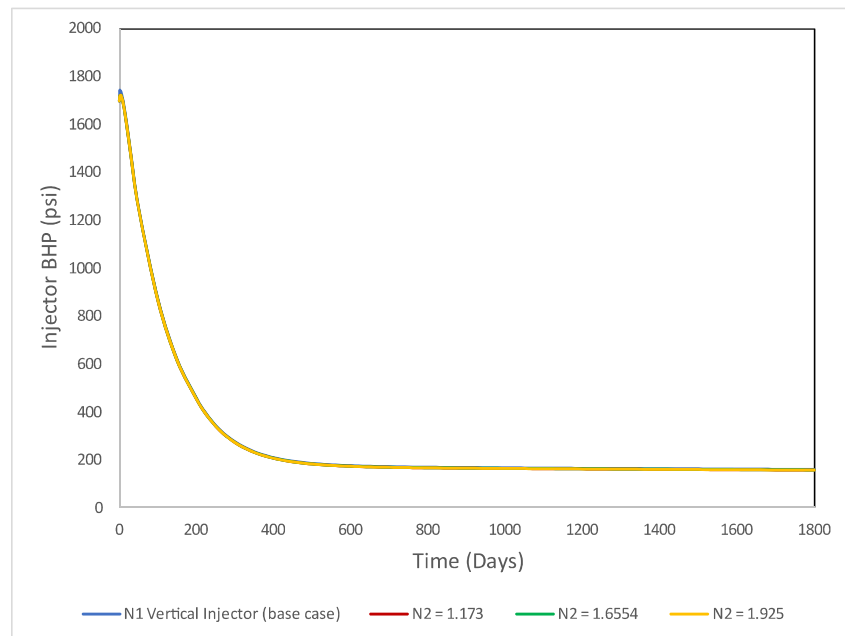


Figure B. 38: Daqing field optimized injection BHP for 3 cP polymer viscosity (HP)

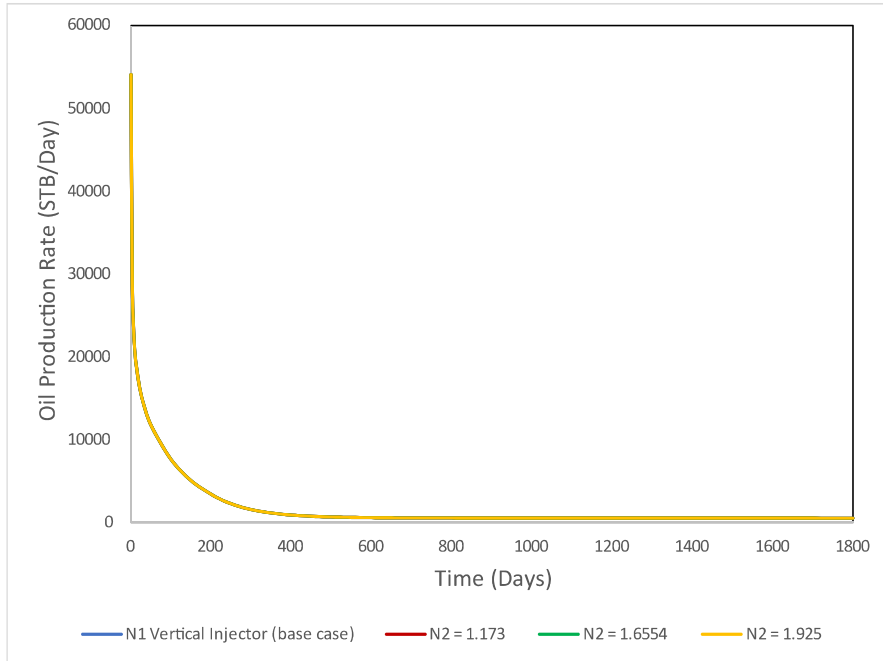


Figure B. 39: Daqing field oil production rate for 3 cP polymer viscosity (HP)

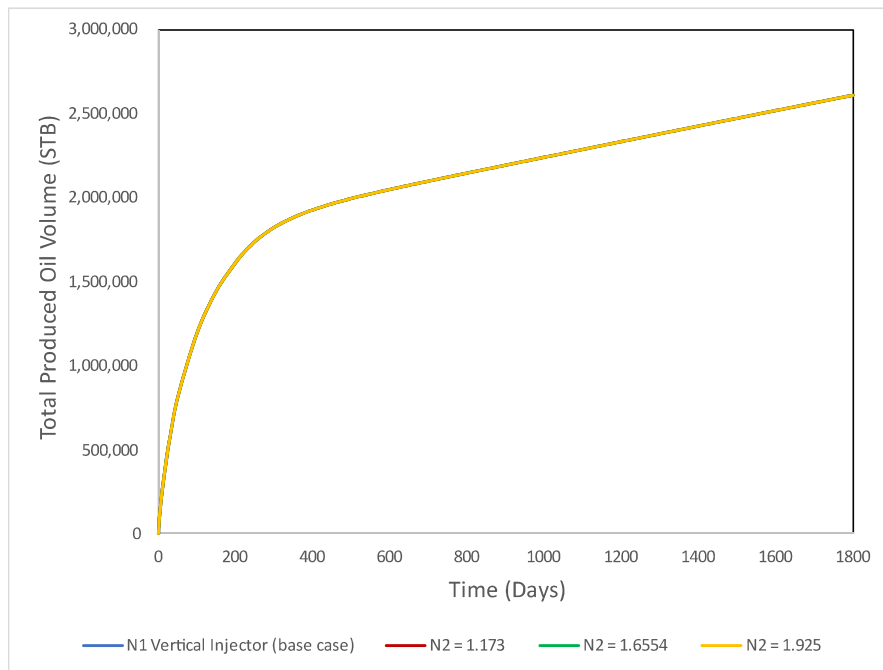


Figure B. 40: Daqing field total produced oil volume for 3 cP polymer viscosity (HP)

- Daqing field 30 cP horizontal producer (HP) case:

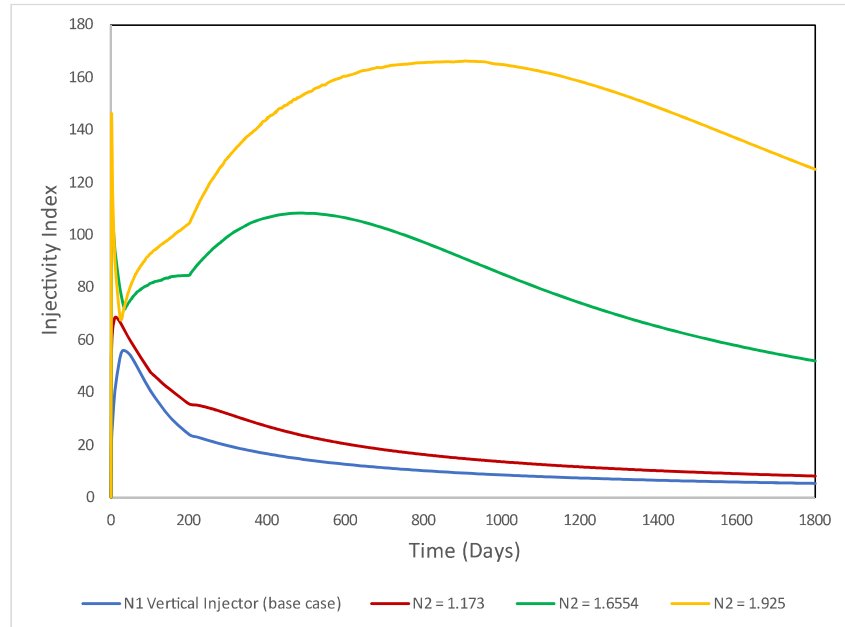


Figure B. 41: Daqing field optimized injectivity for 30 cP polymer viscosity (HP)

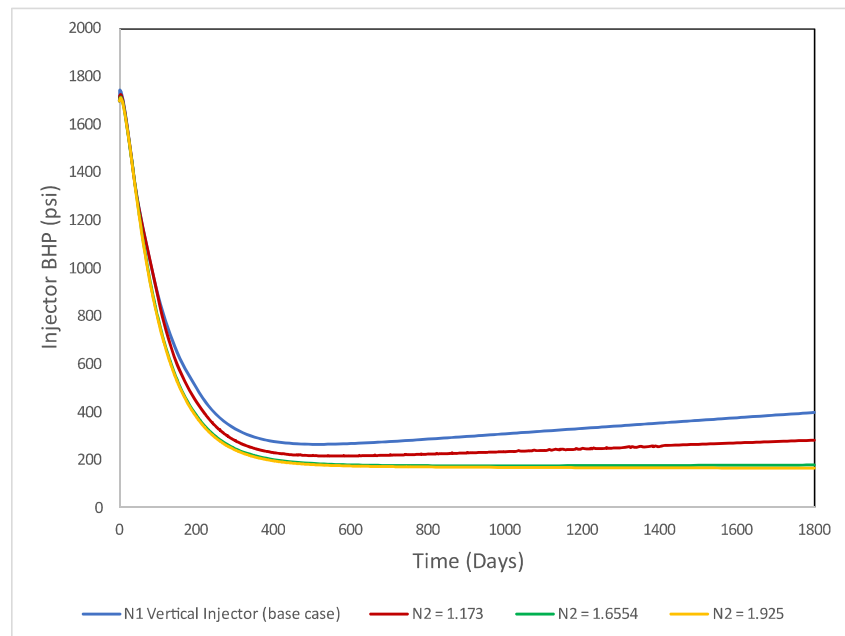


Figure B. 42: Daqing field optimized injection BHP for 30 cP polymer viscosity (HP)

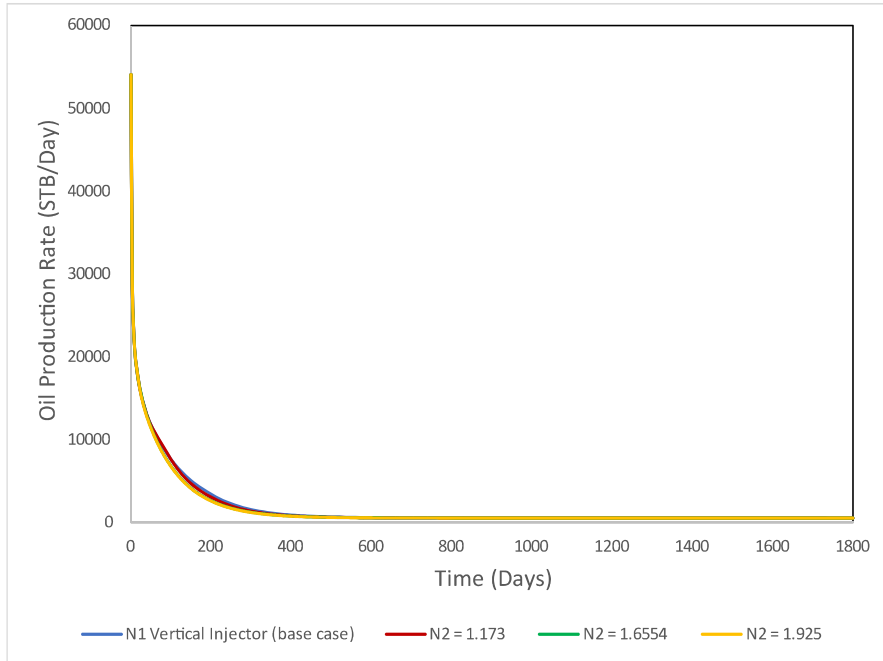


Figure B. 43: Daqing field oil production rate for 30 cP polymer viscosity (HP)

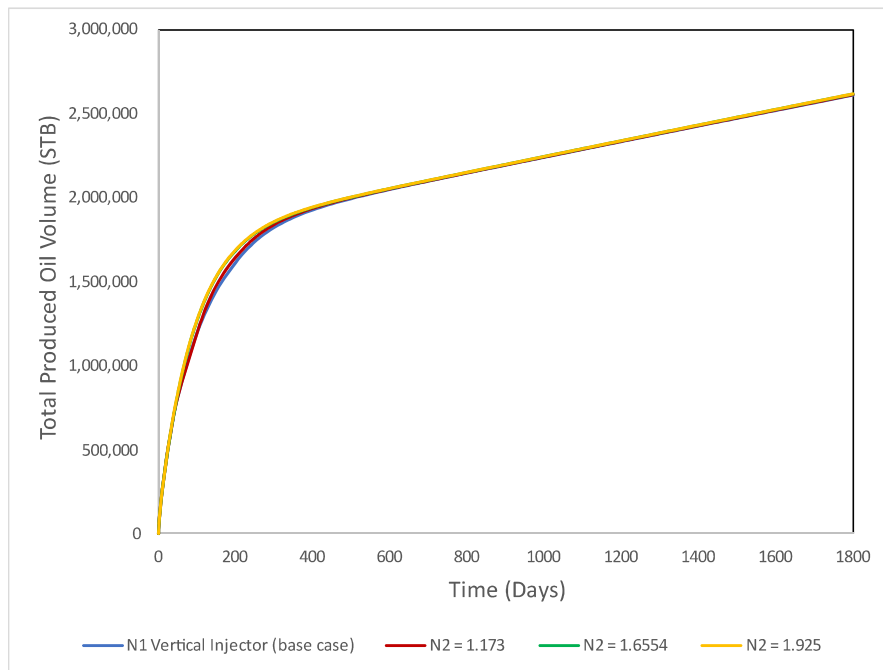


Figure B. 44: Daqing field total produced oil volume for 30 cP polymer viscosity (HP)

- Daqing field **300 cP** horizontal producer (HP) case:

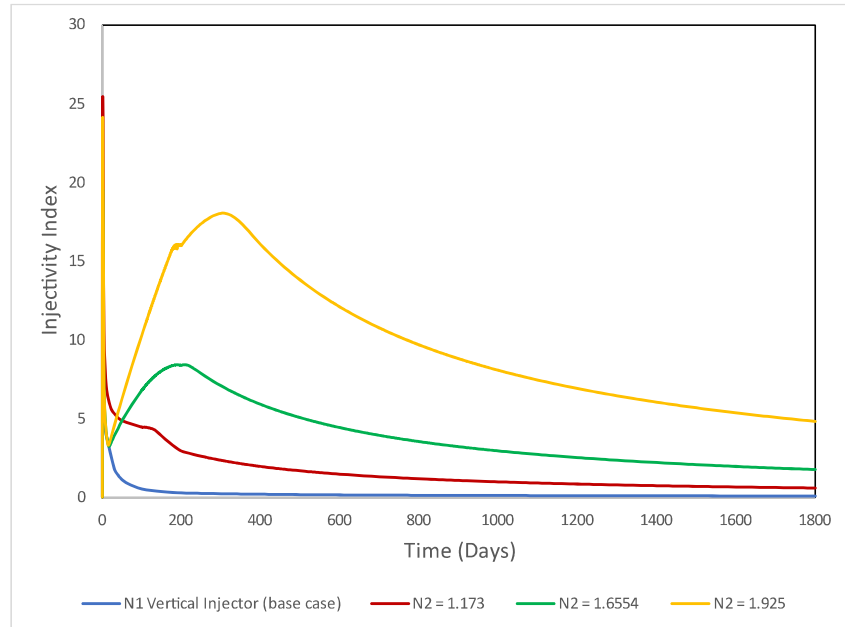


Figure B. 45: Daqing field optimized injectivity for 300 cP polymer viscosity (HP)

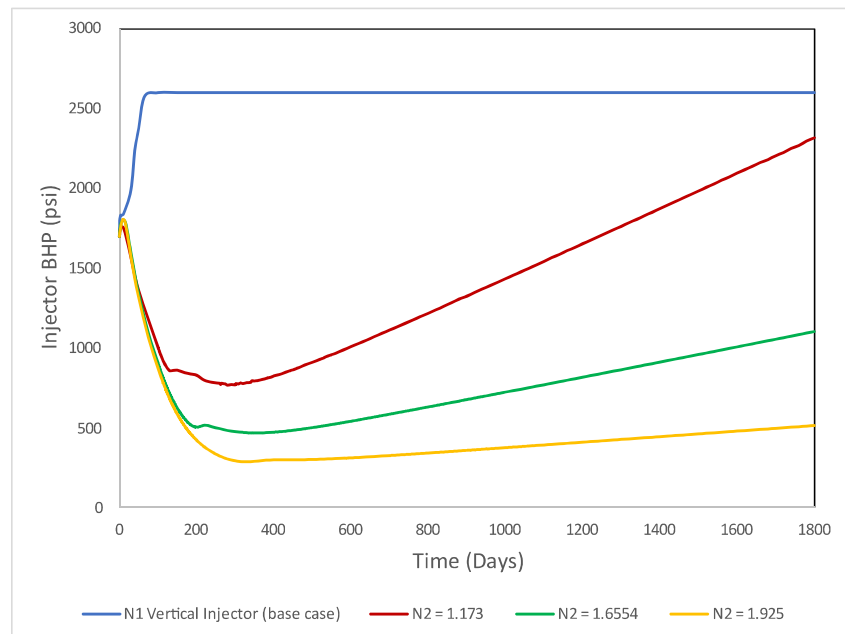


Figure B. 46: Daqing field optimized injection BHP for 300 cP polymer viscosity (HP)

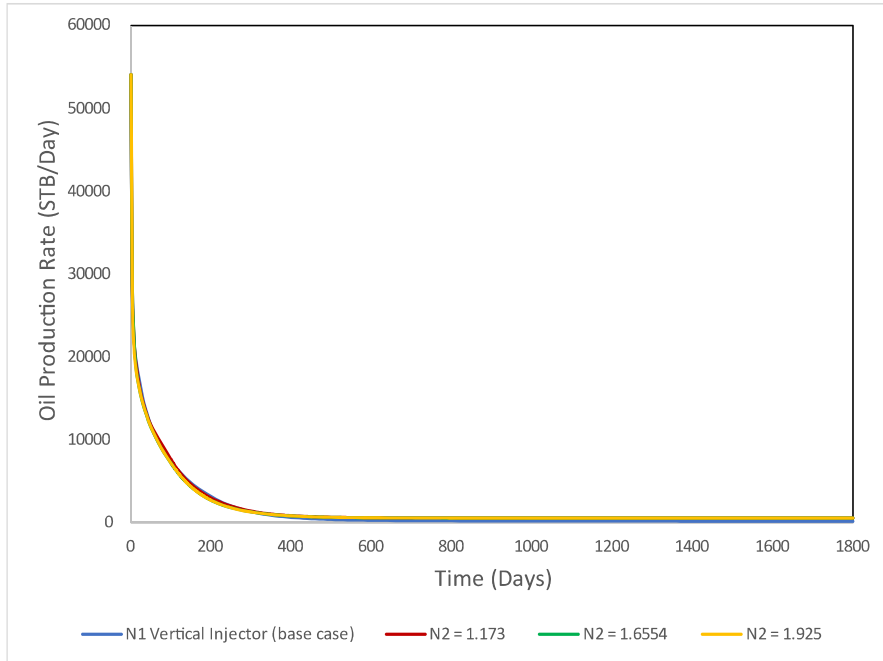


Figure B. 47: Daqing field oil production rate for 300 cP polymer viscosity (HP)

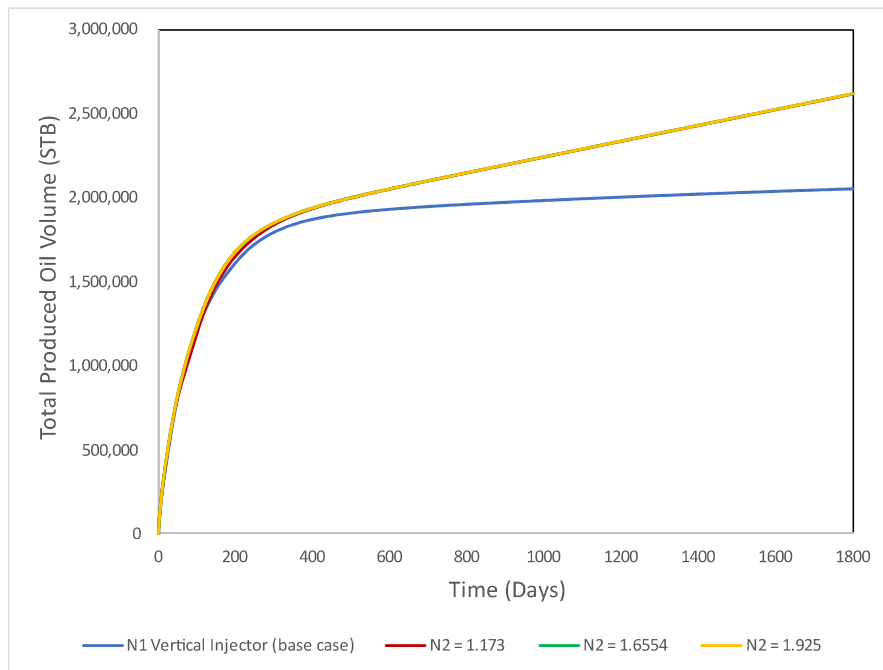


Figure B. 48: Daqing field total produced oil volume for 300 cP polymer viscosity (HP)

➤ **Pelican Lake Field:**

- Pelican Lake field **3 cP** vertical producer (VP) case:

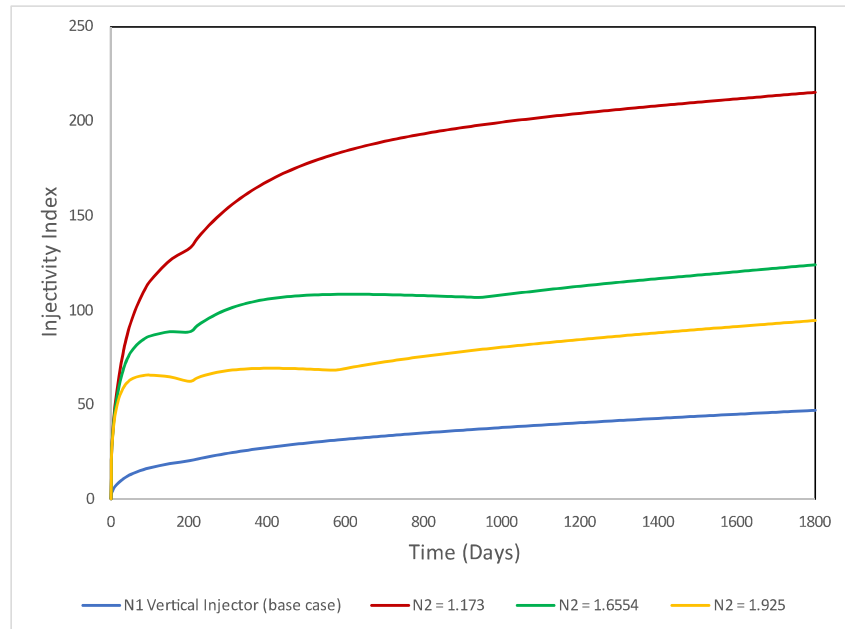


Figure B. 49: Pelican Lake field optimized injectivity for 3 cP polymer viscosity (VP)

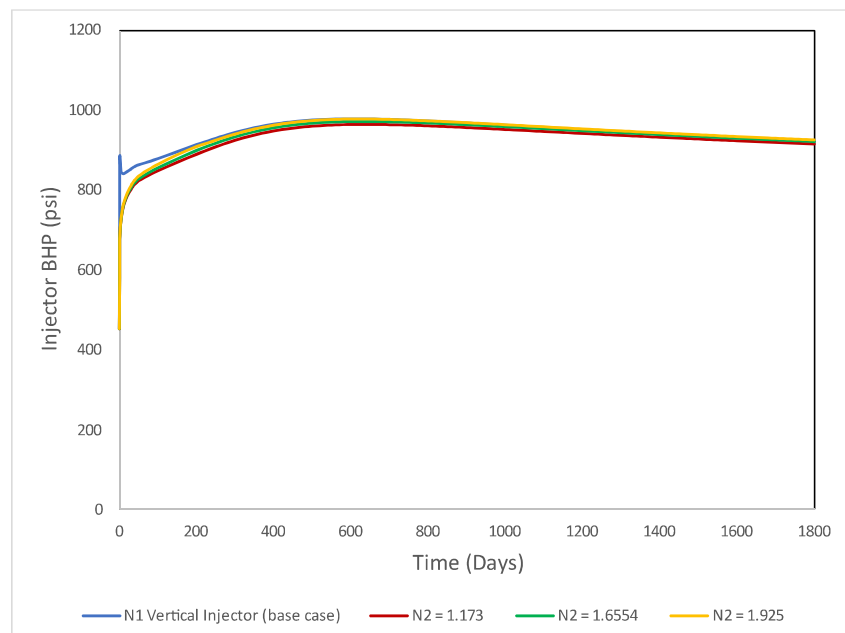


Figure B. 50: Pelican Lake Field optimized injection BHP 3 cP polymer viscosity (VP)

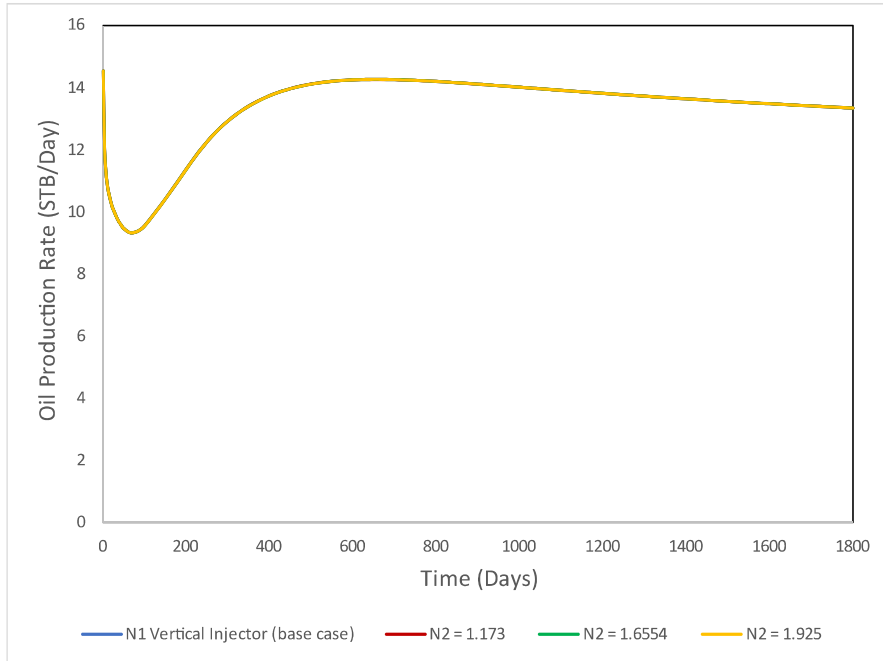


Figure B. 51: Pelican Lake field oil production rate for 3 cP polymer viscosity (VP)

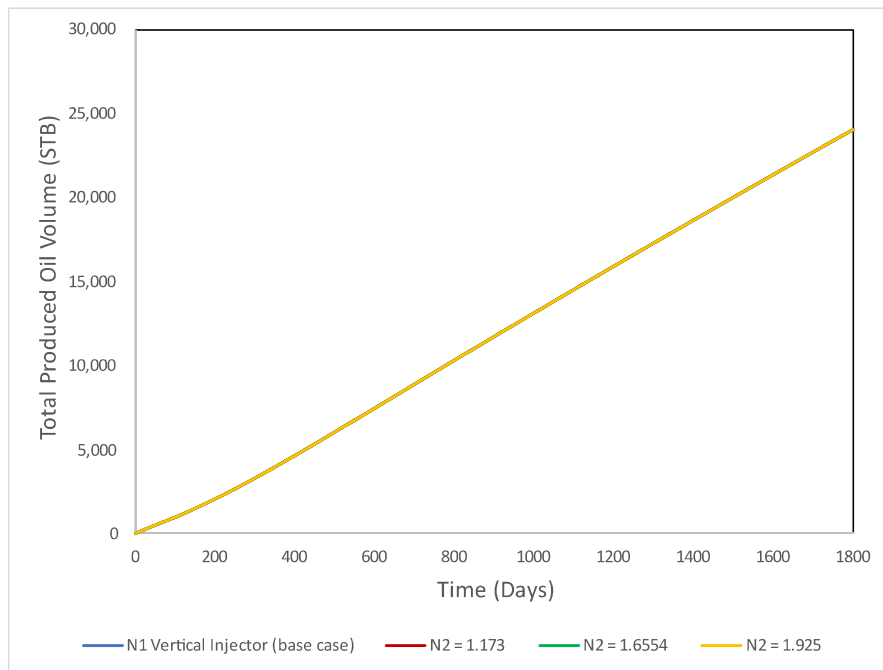


Figure B. 52: Pelican Lake field total produced oil volume 3 cP polymer viscosity (VP)

- Pelican Lake field **30 cP** vertical producer (VP) case:

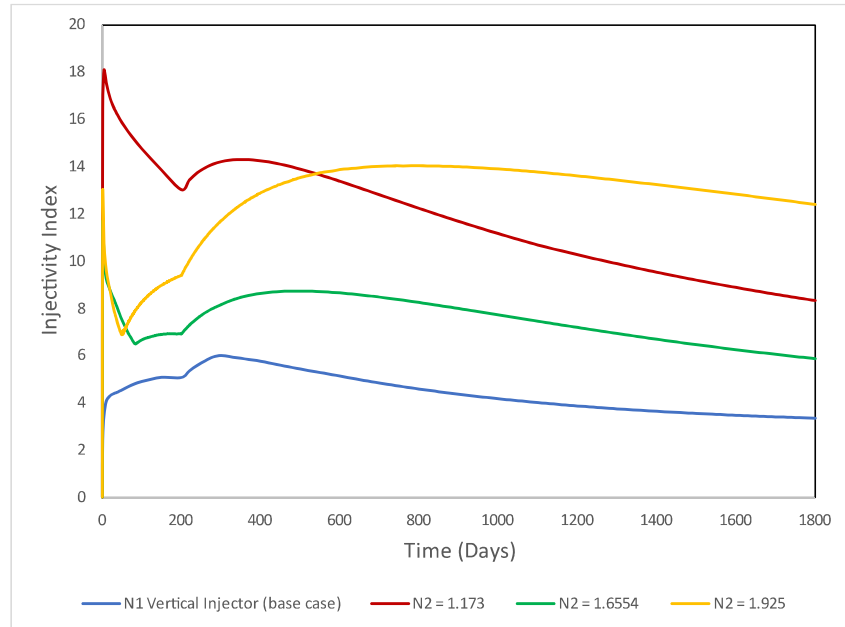


Figure B. 53: Pelican Lake field optimized injectivity for 30 cP polymer viscosity (VP)

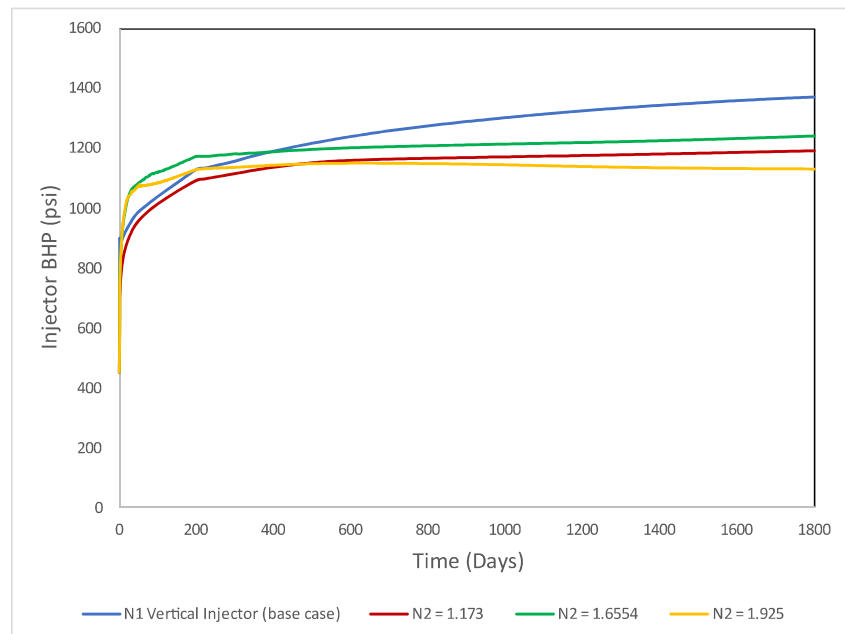


Figure B. 54: Pelican Lake field optimized injection BHP 30 cP polymer viscosity (VP)

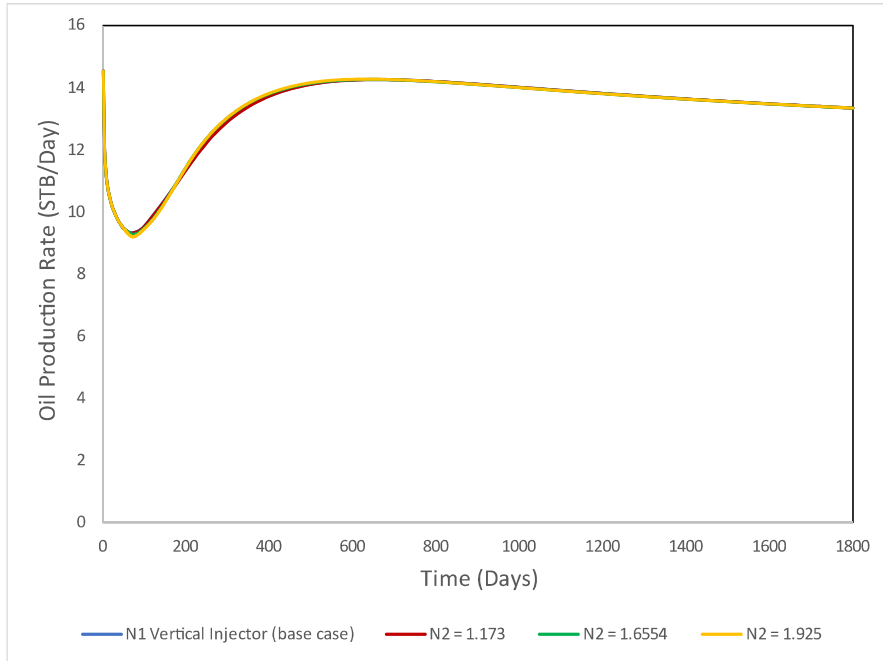


Figure B. 55: Pelican Lake field oil production rate for 30 cP polymer viscosity (VP)

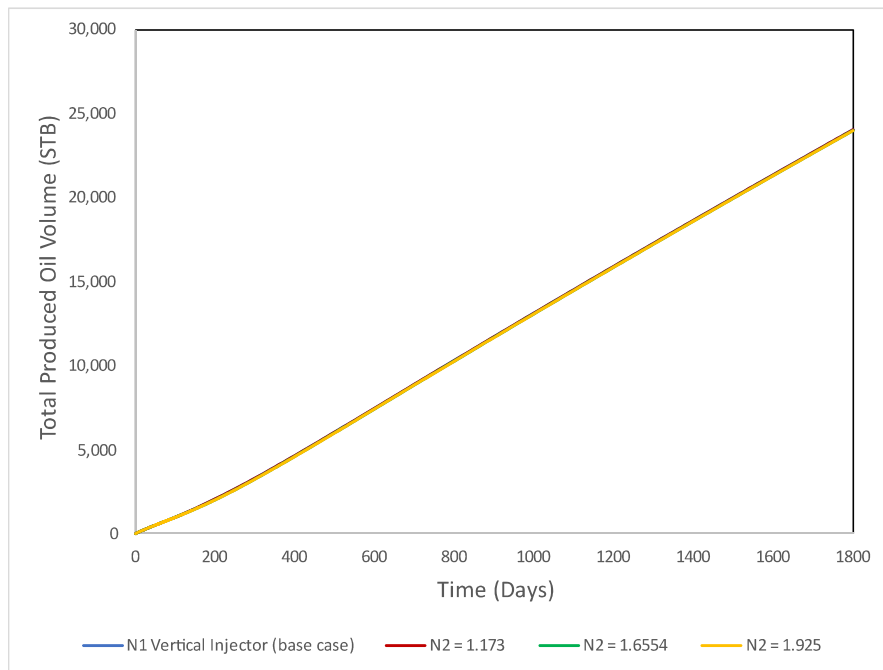


Figure B. 56: Pelican Lake field total produced oil volume 30 cP polymer viscosity (VP)

- Pelican Lake field 3 cP horizontal producer (HP) case:

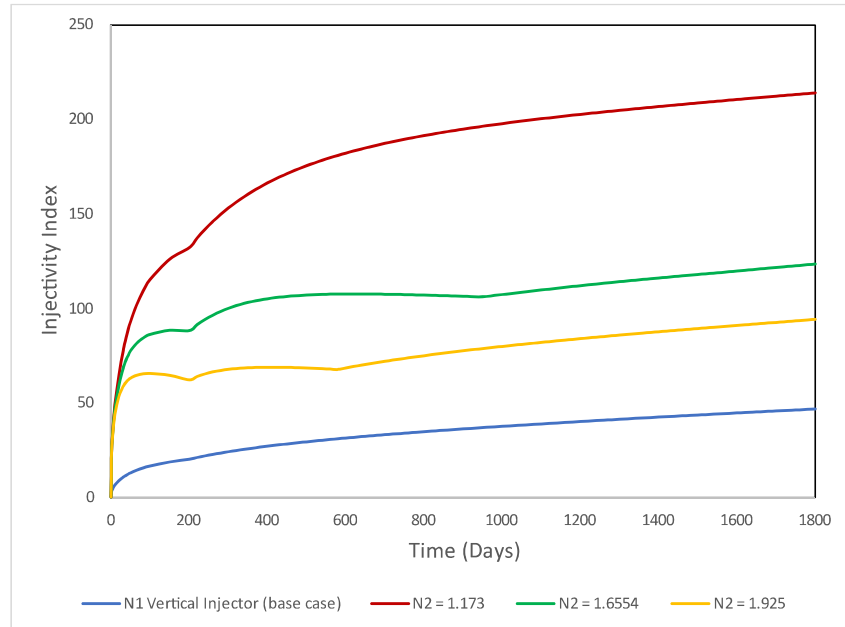


Figure B. 57: Pelican Lake field optimized injectivity for 3 cP polymer viscosity (HP)

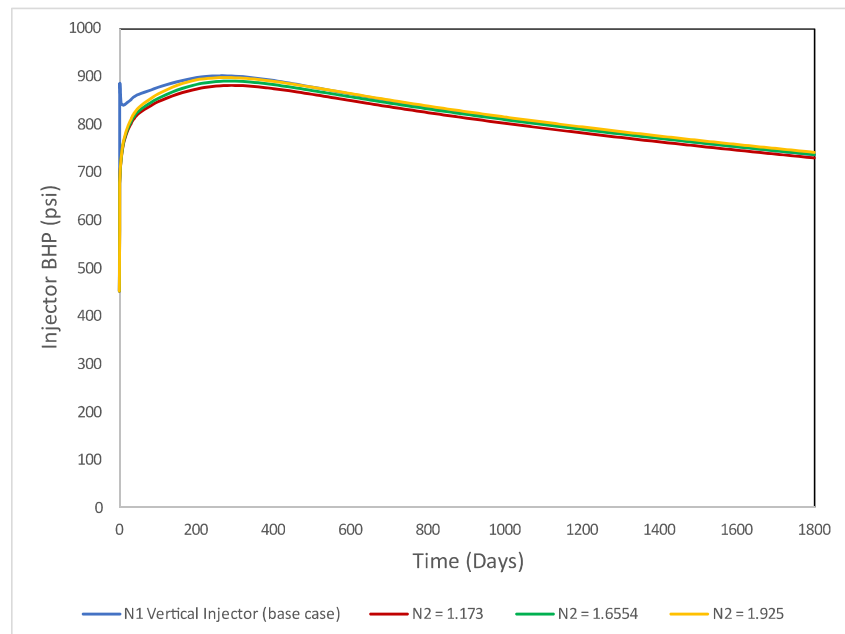


Figure B. 58: Pelican Lake field optimized injection BHP 3 cP polymer viscosity (HP)

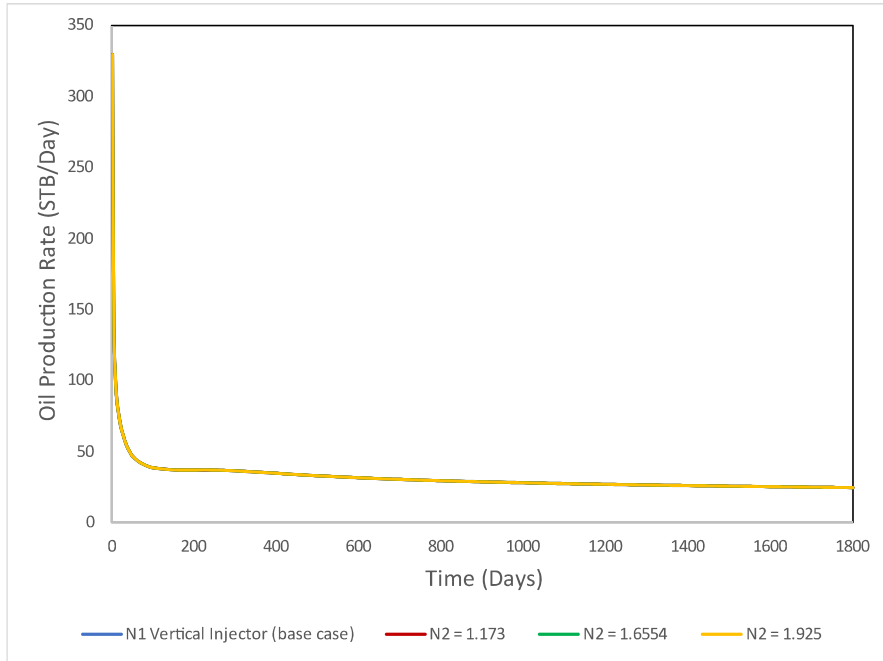


Figure B. 59: Pelican Lake field oil production rate for 3 cP polymer viscosity (HP)

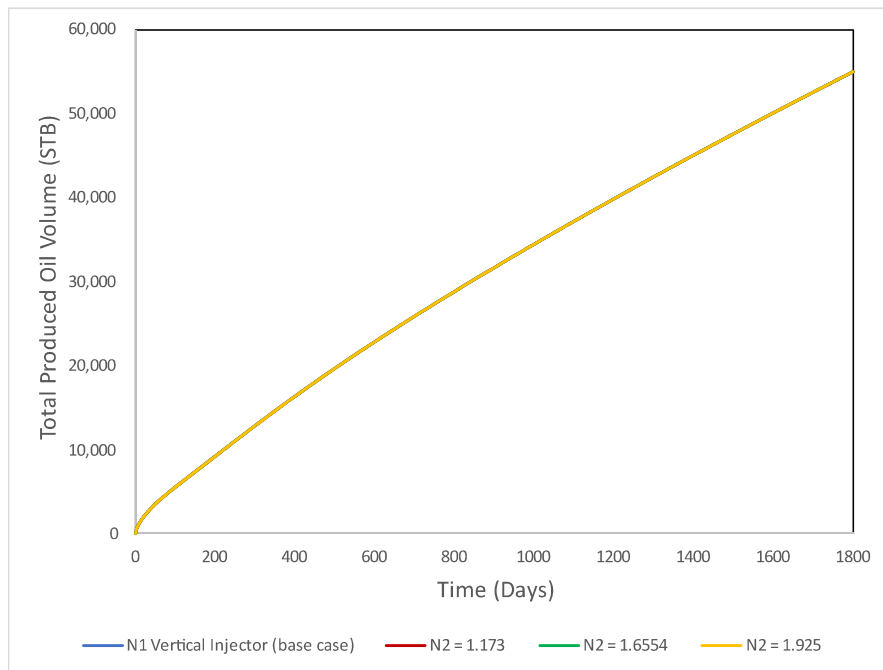


Figure B. 60: Pelican Lake field total produced oil volume 3 cP polymer viscosity (HP)

- Pelican Lake field **30 cP** horizontal producer (HP) case:

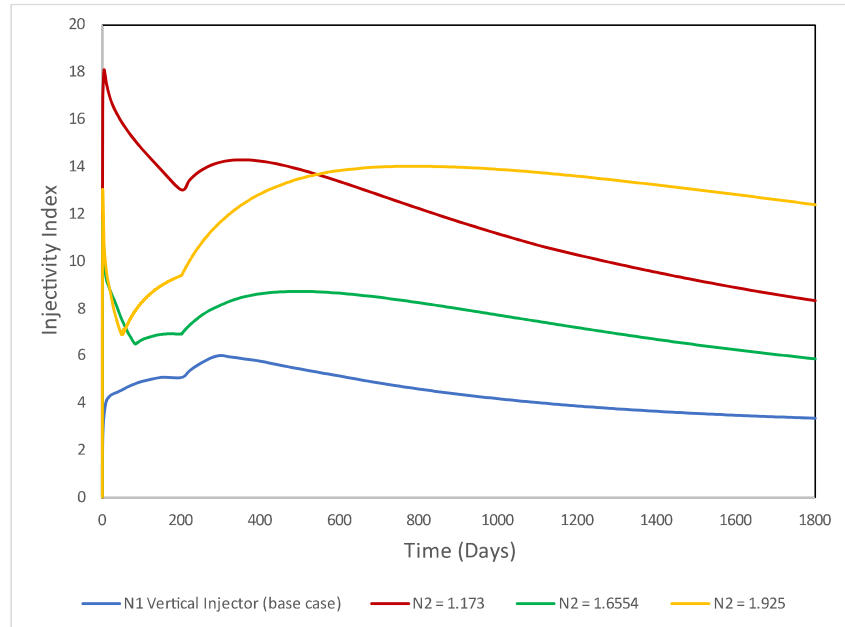


Figure B. 61: Pelican Lake field optimized injectivity for 30 cP polymer viscosity (HP)

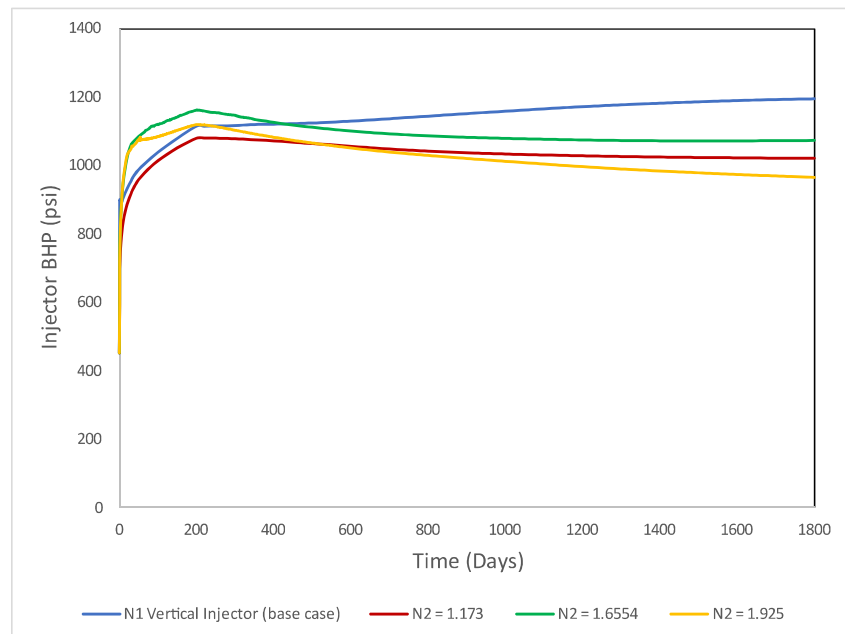


Figure B. 62: Pelican Lake field optimized injection BHP 30 cP polymer viscosity (HP)

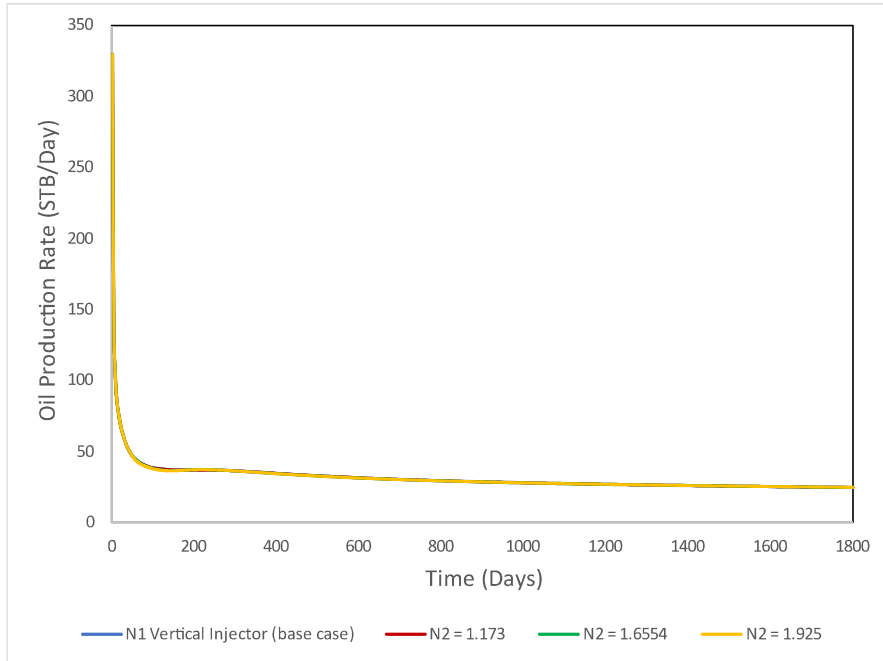


Figure B. 63: Pelican Lake field oil production rate for 30 cP polymer viscosity (HP)

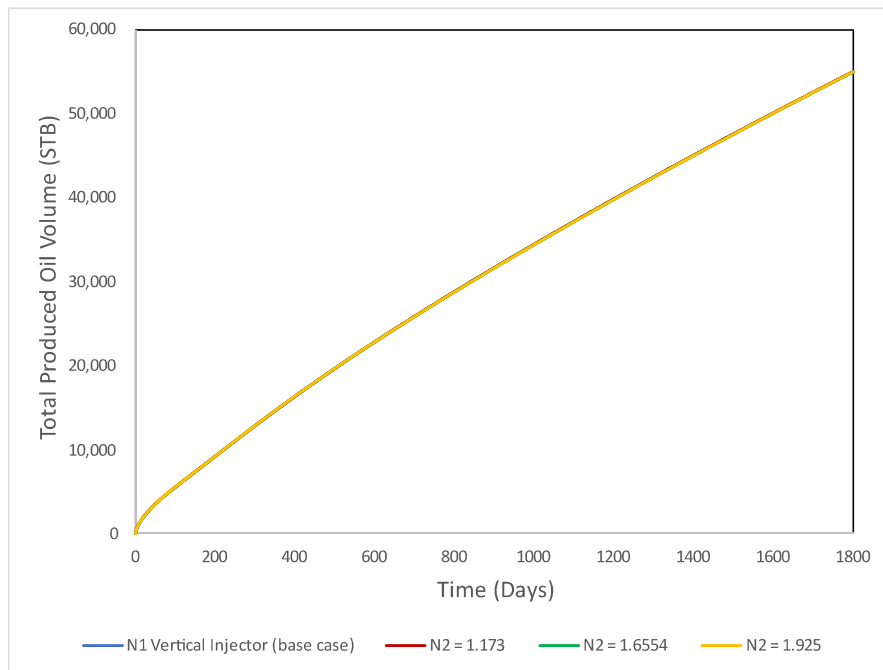


Figure B. 64: Pelican Lake field total produced oil volume 30 cP polymer viscosity (HP)

Vitae



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- Well scale inhibition champion
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Patents : **Mohammed Ali Al-Ameer** and Aqeel Al-Bahrani. ***Drone-Based Acquisition of Wellhead Data and Wireless Chole Adjustment.*** Filed Patent at the United States Patent and Trademark Office (USPTO) with U.S. Patent No. 18733-1458001, **April 2023.**